Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.10.2022

2022

Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM), and is also known as the Independent Market Monitor for PJM (IMM), submits this *2022 Quarterly State of the Market Report for PJM: January through September*.[2] [3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (RAA), the Consolidated Transmission Owners Agreement (CTOA) or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M.
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2022 Quarterly State of the Market Report for PJM: January through September.*

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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%

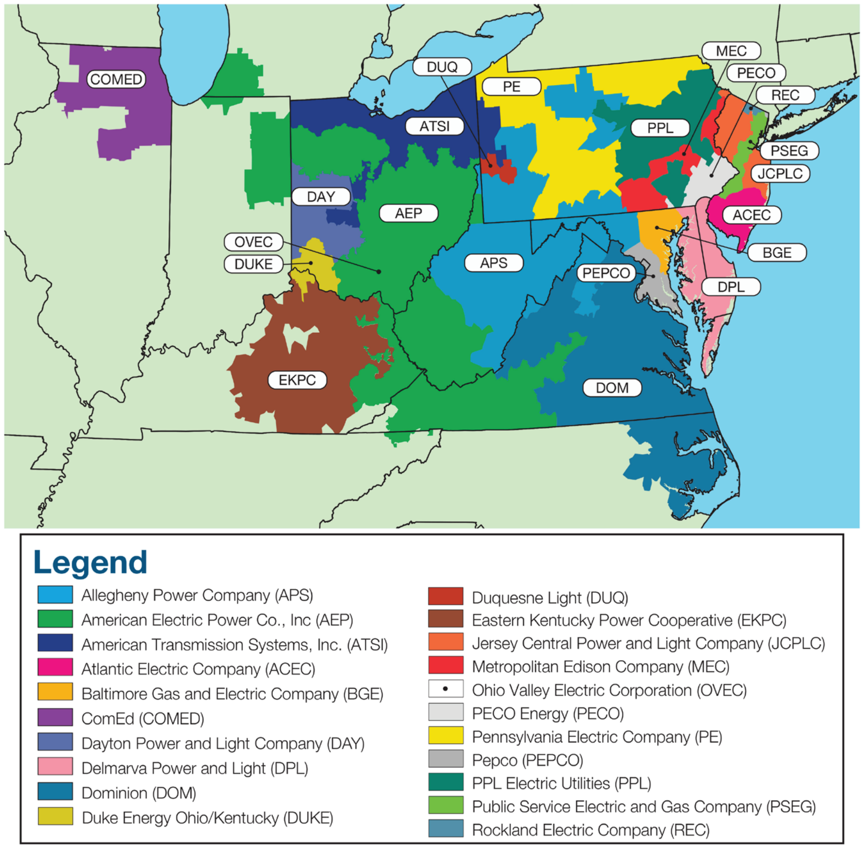
PJM Market Background

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.

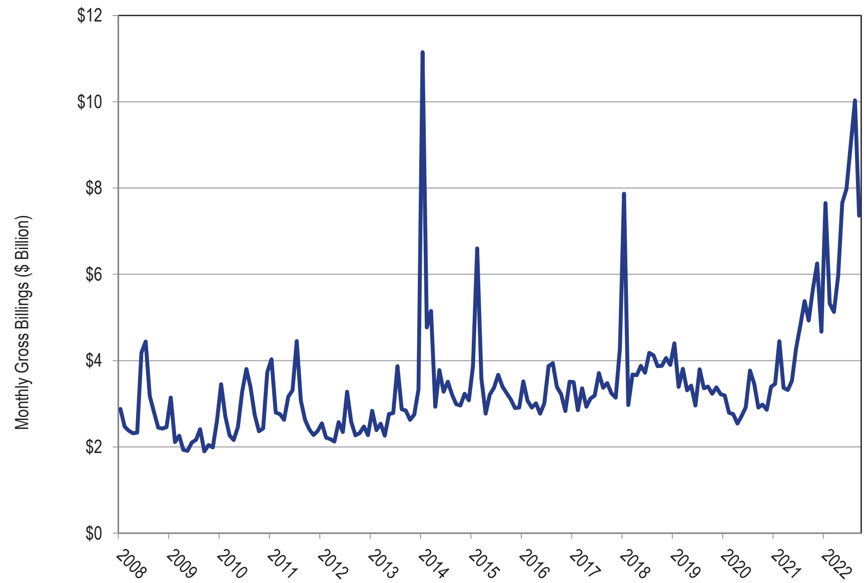
1 In Table 01, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.
2 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
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]

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.

- 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]

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.

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).

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 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.

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 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.

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.

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

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).
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.

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

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

The MMU also tracks PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.
- **Withdrawn:** The MMU no longer makes the recommendation because it has become irrelevant or because it has been replaced by another recommendation.

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.[6]

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

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.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when 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.)[7]
- 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

7 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.

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.)[8]
- 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.)
- 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.)[9]

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

9 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.

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 determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[10]
- 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.)

10 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.

- 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.)[11]
- 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.)
- 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.[12] (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.[13] [14] (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.)

11 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.

12 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.

13 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.

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

- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the 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 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.)[15]
- 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.)[16]

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 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)

15 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
16 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 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.)[17]
- 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.)

17 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 5, Capacity Market

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18] [19] (Priority: High. First reported 2013. Status: Not adopted.)
- 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.)[20]
- 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.[21] (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

18 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 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).
20 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).
21 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).

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.)[22]
- 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.)
- 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.)

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.)[23]
- 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.[24] [25] 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.)

22 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).

23 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>.

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

25 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- 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 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.)[26]

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.[27] (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.[28] (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

26 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).

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

28 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).

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.)
- 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.)[29]
- 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.)[30]

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.)

29 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).

30 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).

- 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 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 6, Demand Response

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated

as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)

- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[31] (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.[32] (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.)
- 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

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

32 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.

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.[33])
- 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.)

33 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 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.)
- 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 7, Net Revenue

- 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 8, Environmental and Renewables

- 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 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- 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.)[34]
- 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.)

34 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.

- 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 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 10, Ancillary Services

- 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.[35])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was

35 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[36] FERC rejected.[37])

- 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.[38])
- 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.[39])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[40])
- 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.)
- 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.)

36 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.
37 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
38 *Id.*
39 *Id.*
40 *Id.*

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: 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.[41] 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

41 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.

as defined by PJM.[42] (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity 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.[43] (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.[44] (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.[45] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

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

42 *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>.
43 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>.
44 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.
45 Ibid.

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.)[46]
- 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.)[47]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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.[48] (Priority: Medium. First reported 2015. Status: Not adopted.)

46 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).

47 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).

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

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 13, FTRs and ARRs

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.)[49]
- 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.)

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

- 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.[50] (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.)
- 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.)

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

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2022.

Table 3-1 The energy market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM 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.[1] 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.[2] 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.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.[4] 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.

1 OATT Attachment M (PJM Market Monitoring Plan).
2 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).
3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
4 175 FERC ¶ 61,231 (2021).

Overview

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.

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.)[5]
- 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.)[6]
- 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

5 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.

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

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.)

- 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.)[7]

7 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.

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

determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[8]

- 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.)[9]
- 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.)

8 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.

9 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.[10] (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.[11] [12] (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

10 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.

11 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.

12 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.)[13]
- 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.)[14]

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.)

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 NOx 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.

13 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
14 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.[15] 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

15 177 FERC ¶ 61,209 (2021).

fast start pricing prioritizes minimizing uplift over minimizing production costs.[16] 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.[17] 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.[18] 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.[19] 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.[20] The MMU recommendations would shorten the solution

16 See 173 FERC ¶ 61,244 (2020).

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

18 See 175 FERC ¶ 61,231 (2021).

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

20 *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.

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

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.

Figure 3-1 shows real-time and day-ahead hourly supply curves in the summer of 2021 and 2022.[21] [22] The real-time supply curve includes hourly on peak average offers. The real-time supply curve includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

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.

21 Real-time supply includes real-time generation offers and import MWh.
22 The supply curve period is from June 1 to August 31.

Figure 3-1 Real-time and day-ahead hourly supply curves: Summers of 2021 and 2022

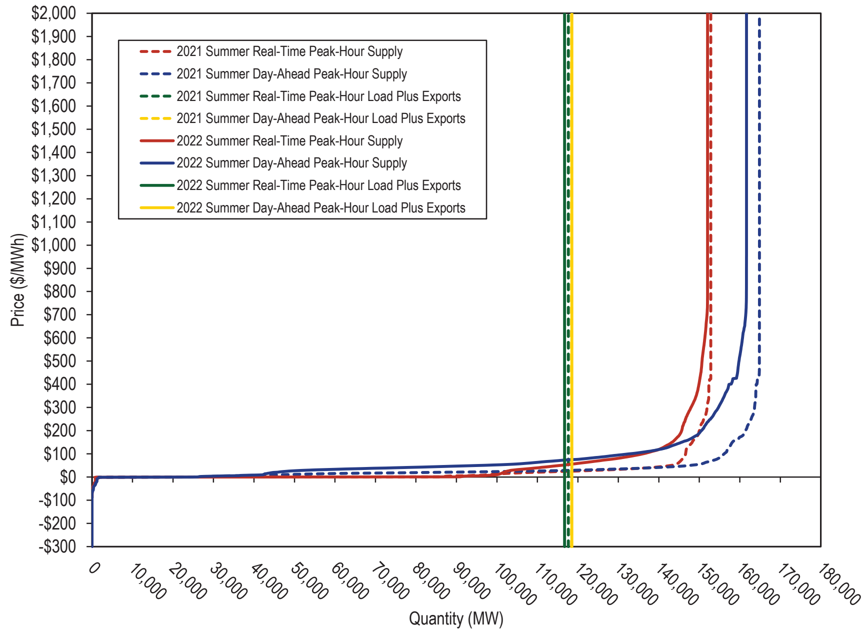


Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

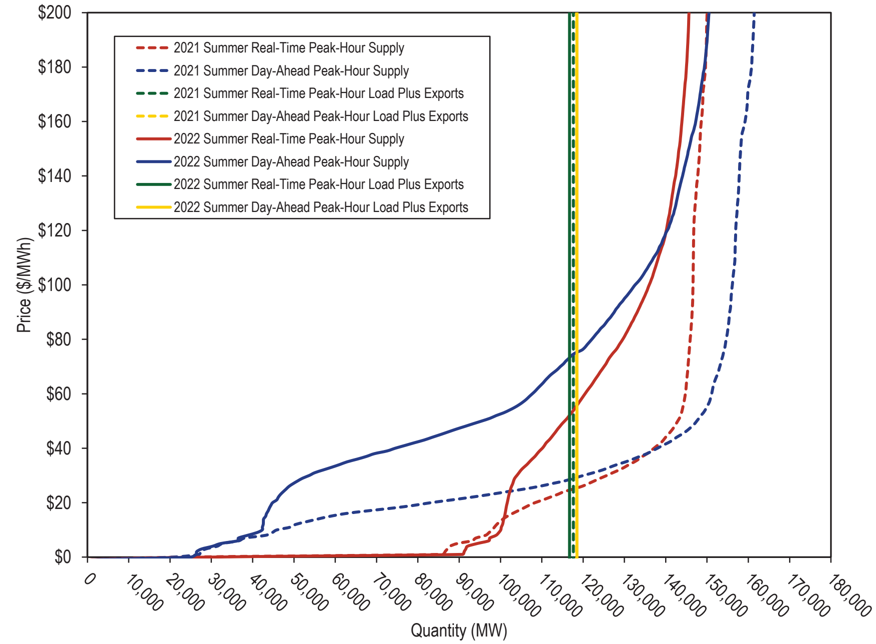


Table 3-2 shows the price elasticity of the real-time supply curve for the on peak hours in the summers of 2021 and 2022 by load level.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied (GW) to a change in price:

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

The supply curve is defined to be elastic when elasticity is greater than 1.0. The quantity supplied is more sensitive to changes in price the higher the elasticity. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the calculated elasticity is low throughout.

Table 3-2 Price elasticity of the supply curve

	GW			
Summer	Min - 95	95 - 115	115 - 135	135 - Max
2019	0.020	0.302	0.415	0.003
2020	0.026	0.256	0.353	0.003
2021	0.017	0.104	0.286	0.005
2022	0.014	0.027	0.178	0.013

Real-Time Supply

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.[23]

The real-time hourly average cleared supply including imports in the first nine months of 2022 increased by 1.6 percent from the first nine months of 2021, from 96,519 MWh to 98,064 MWh.

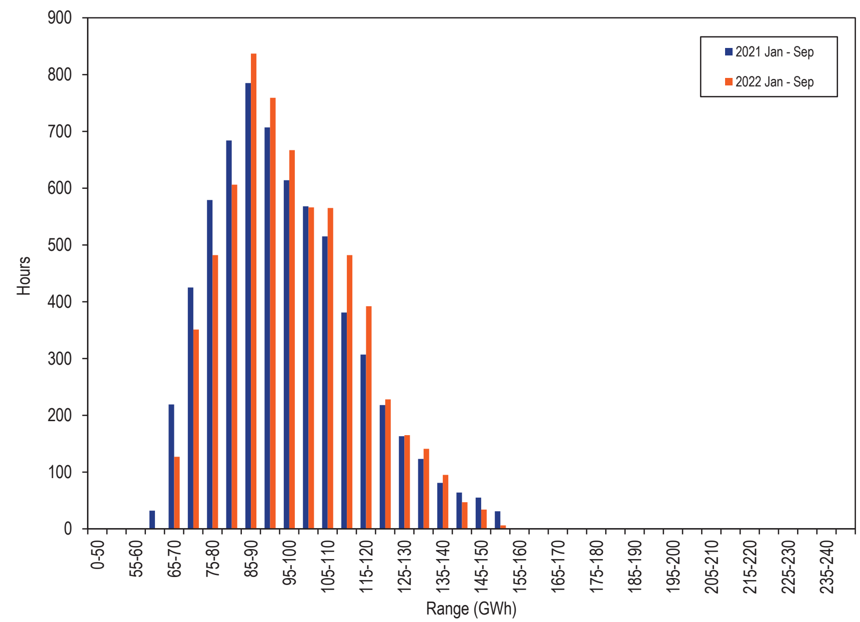
In the PJM Real-Time Energy Market, there are three types of supply offers:

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

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of the real-time generation plus imports for the first nine months of 2021 and 2022.

Figure 3-3 Distribution of real-time generation plus imports: January through September, 2021 and 2022[24]



PJM Real-Time Average Supply

Table 3-3 shows the real-time hourly average supply and its standard deviation for the first nine months of 2001 through 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.

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

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

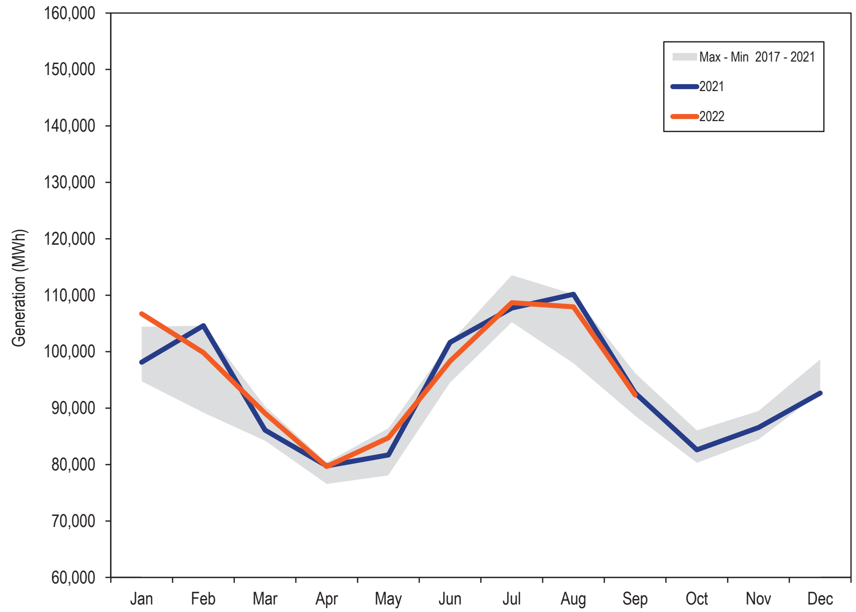
Table 3-3 Real-time hourly average generation and generation plus imports: January through September, 2001 through 2022

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)
2020	92,226	17,790	92,983	17,883	(3.5%)	3.4%	(3.8%)	2.9%
2021	95,792	18,039	96,519	18,173	3.9%	1.4%	3.8%	1.6%
2022	96,397	16,816	98,064	17,031	0.6%	(6.8%)	1.6%	(6.3%)

PJM Real-Time Monthly Average Generation

Figure 3-4 compares the real-time monthly average generation in 2021 and the first nine months of 2022 with the historic five year range. In January 2022, the monthly average generation was higher than the maximum of the past five years, primarily as a result of weather related demand.

Figure 3-4 Real-time monthly average generation: 2021 through September 2022



Day-Ahead Supply

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.

The day-ahead hourly average supply in the first nine months of 2022, including INCs, UTCs and exports, increased by 5.6 percent from the first nine months of 2021, from 104,970 MWh to 110,875 MWh.

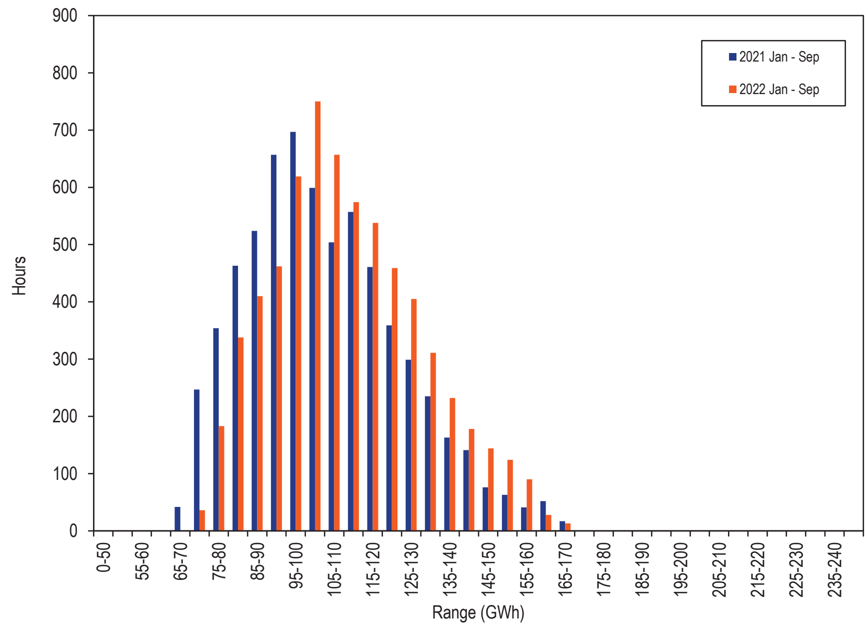
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

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

PJM Day-Ahead Supply Duration

Figure 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and imports for the first nine months of 2021 and 2022.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through September, 2021 and 2022[25]



PJM Day-Ahead Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for the first nine months of each year from 2001 through 2022. 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.

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

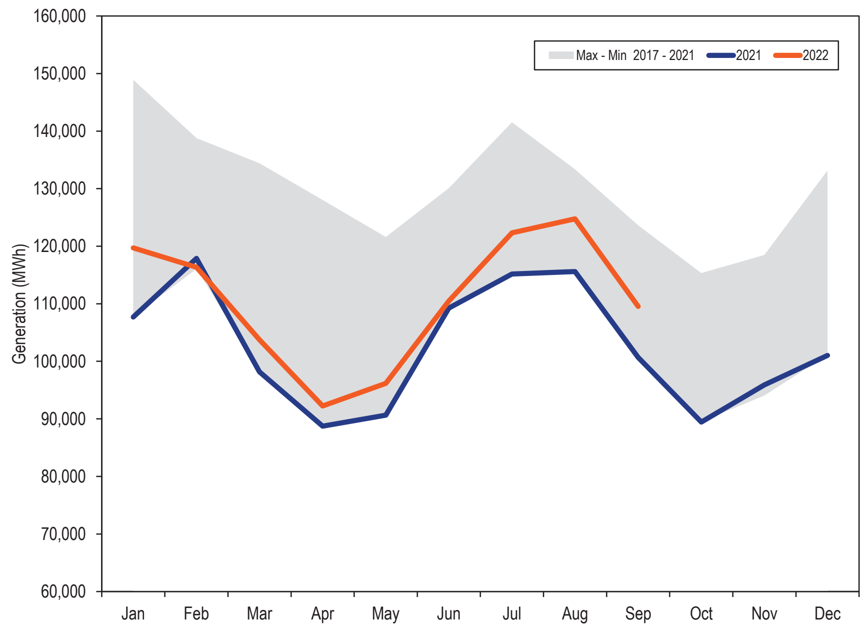
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through September, 2001 through 2022

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)
2020	115,205	20,611	115,386	20,577	(3.1%)	3.0%	(3.2%)	2.9%
2021	104,785	20,136	104,970	20,154	(9.0%)	(2.3%)	(9.0%)	(2.1%)
2022	110,598	19,369	110,875	19,455	5.5%	(3.8%)	5.6%	(3.5%)

PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average supply including increment offers and up to congestion transactions for the first nine months of 2021 and 2022 with the historic five year range.

Figure 3-6 Day-ahead monthly average cleared supply: 2021 through September 2022



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply for the first nine months of 2021 and 2022. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead supply less the total real-time supply. The total physical day-ahead average generation less the total physical real-time average generation in the first nine months of 2022 increased 464 MWh from the first nine months of 2021, from -630 MWh to -166 MWh. The total day-ahead average supply less the total real-time average supply in the first nine months of 2022 increased 4,360 MWh from the first nine months of 2021, from 8,451 MWh to 12,811 MWh.

Table 3-5 Day-ahead and real-time hourly supply (MWh): January through September, 2021 and 2022

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Sep	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2021	95,162	2,308	7,315	185	104,970	95,792	96,519	(630)	8,451
	2022	96,231	3,463	10,904	277	110,875	96,397	98,064	(166)	12,811
Median	2021	92,790	2,197	7,159	120	102,324	93,229	93,904	(439)	8,420
	2022	93,568	3,393	10,221	226	108,409	94,370	95,821	(802)	12,589
Standard Deviation	2021	18,317	1,050	2,997	232	20,154	18,039	18,173	278	1,981
	2022	17,739	1,058	3,921	246	19,455	16,816	17,031	923	2,424
Peak Average	2021	104,593	2,825	8,511	171	116,099	104,761	105,571	(168)	10,528
	2022	104,740	3,797	11,866	325	120,728	104,383	106,177	357	14,552
Peak Median	2021	102,827	2,808	8,437	105	113,708	102,446	103,277	381	10,431
	2022	103,260	3,731	11,298	282	118,704	102,725	104,461	535	14,244
Peak Standard Deviation	2021	17,121	1,025	2,783	208	18,111	17,335	17,440	(214)	671
	2022	16,413	1,029	3,836	261	17,668	15,736	15,910	677	1,759
Off-Peak Average	2021	86,916	1,857	6,269	197	95,238	87,951	88,604	(1,035)	6,634
	2022	88,717	3,167	10,055	234	102,173	89,346	90,900	(628)	11,273
Off-Peak Median	2021	85,029	1,768	5,846	130	92,205	86,187	86,740	(1,158)	5,465
	2022	86,626	3,084	9,308	178	100,478	87,834	89,018	(1,207)	11,461
Off-Peak Standard Deviation	2021	15,063	843	2,779	250	16,481	14,677	14,793	386	1,688
	2022	15,307	993	3,797	222	16,603	14,416	14,604	891	1,999

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day in the first nine months of 2022. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average volumes by hour of the day): January through September, 2022

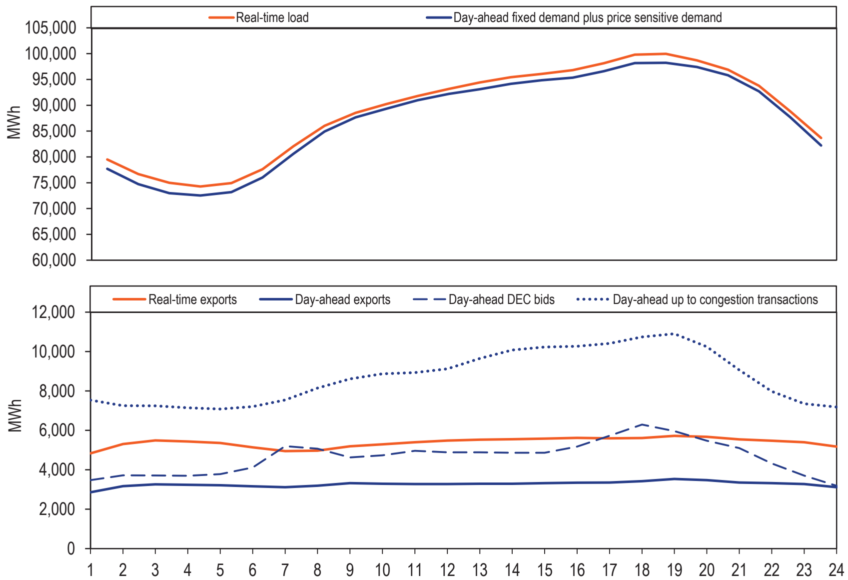
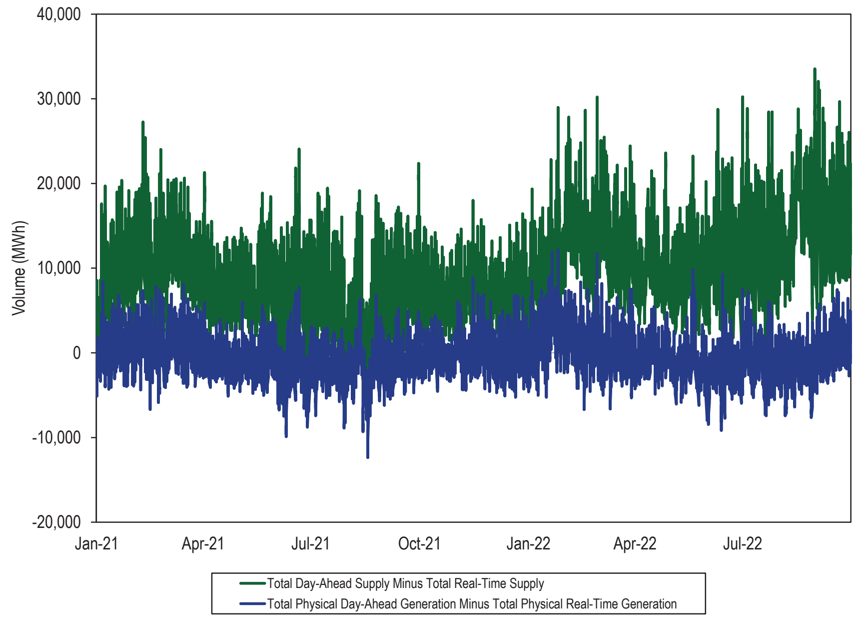


Figure 3-8 shows the difference between day-ahead and real-time daily average supply in 2021 and the first nine months of 2022.

Figure 3-8 Difference between day-ahead and real-time daily average supply: 2021 through September 2022



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports, and in the day-ahead energy market, includes virtual transactions.[26]

Table 3-6 shows the peak load plus exports for the first nine months of 2009 through 2022. The real-time hourly peak load plus exports in the first nine

26 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

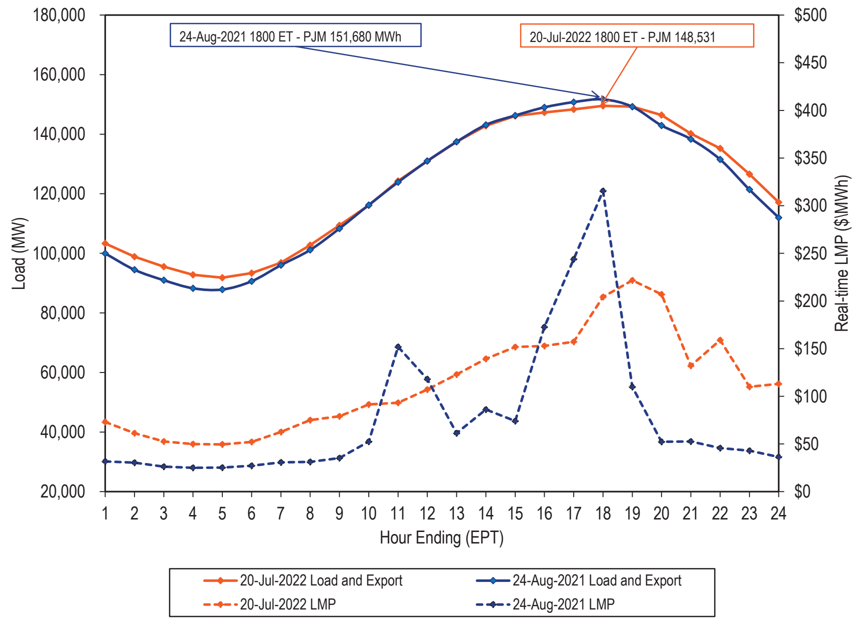
months of 2022 was 149,531 MWh (144,356 MWh of load plus 5,175 MWh of gross exports) in the HE 1800 on July 20, 2022, which was 1.4 percent, 2,150 MWh, lower than the PJM peak load plus exports in first nine months of 2021, which was 151,680 MWh in the HE 1800 on August 24, 2021.

Table 3-6 Actual footprint peak load plus export: January through September, 2009 through 2022[27 28]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Mon, August 10	16	135,923	NA	NA
2010	Wed, July 07	17	149,376	13,453	9.9%
2011	Thu, July 21	17	169,290	19,915	13.3%
2012	Tue, July 17	18	166,081	(3,210)	(1.9%)
2013	Thu, July 18	17	157,277	(8,804)	(5.3%)
2014	Tue, June 17	18	142,428	(14,850)	(9.4%)
2015	Fri, February 20	8	144,850	2,422	1.7%
2016	Thu, August 11	17	154,743	9,893	6.8%
2017	Thu, July 20	16	148,343	(6,400)	(4.1%)
2018	Tue, August 28	17	152,509	4,166	2.8%
2019	Fri, July 19	18	153,589	1,080	0.7%
2020	Mon, July 20	18	148,996	(4,593)	(3.0%)
2021	Tue, August 24	18	151,680	2,684	1.8%
2022	Wed, July 20	18	149,531	(2,150)	(1.4%)

Figure 3-9 compares prices and demand on the peak load days for the first nine months of 2021 and 2022. The real-time average LMP for August 24, 2021, peak load hour was $315.42 per MWh, and for July 20, 2022, peak load hour it was $204.29 per MWh.

Figure 3-9 Peak load and export day comparison



Real-Time Demand

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.[29]

The real-time hourly average demand including exports in the first nine months of 2022 increased by 1.5 percent from the first nine months of 2021, from 94,746 MWh to 96,196 MWh.

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

- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to

27 Peak loads shown are Power accounting load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions," for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

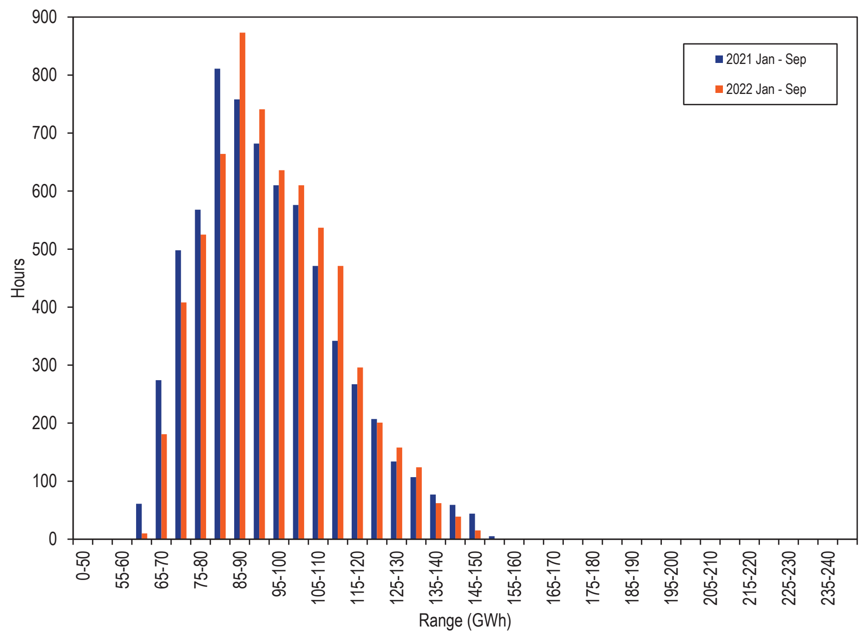
29 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority's checkout process.

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports for the first nine months of 2021 and 2022.[30]

Figure 3-10 Distribution of real-time load plus exports: January through September, 2021 and 2022[31]



PJM Real-Time Average Load

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 through 2022.[32] 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.

Table 3-7 Real-time hourly average load and load plus exports: January through September, 2001 through 2022

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)
2020	85,886	17,201	91,356	17,464	(4.4%)	2.4%	(3.8%)	3.2%
2021	89,515	16,875	94,746	17,748	4.2%	(1.9%)	3.7%	1.6%
2022	90,514	16,367	96,196	16,581	1.1%	(3.0%)	1.5%	(6.6%)

30 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

32 Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. 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.

PJM Real-Time Monthly Average Load

Figure 3-11 compares the real-time monthly average load plus exports in 2021 and the first nine months of 2022, with the historic five year range.

Figure 3-11 Real-time monthly average hourly load plus exports: 2021 through September 2022

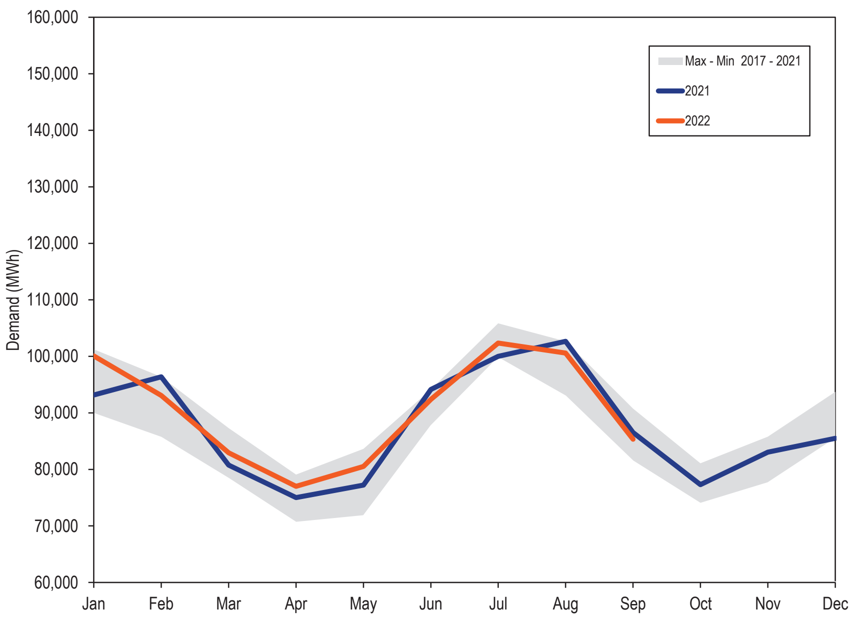
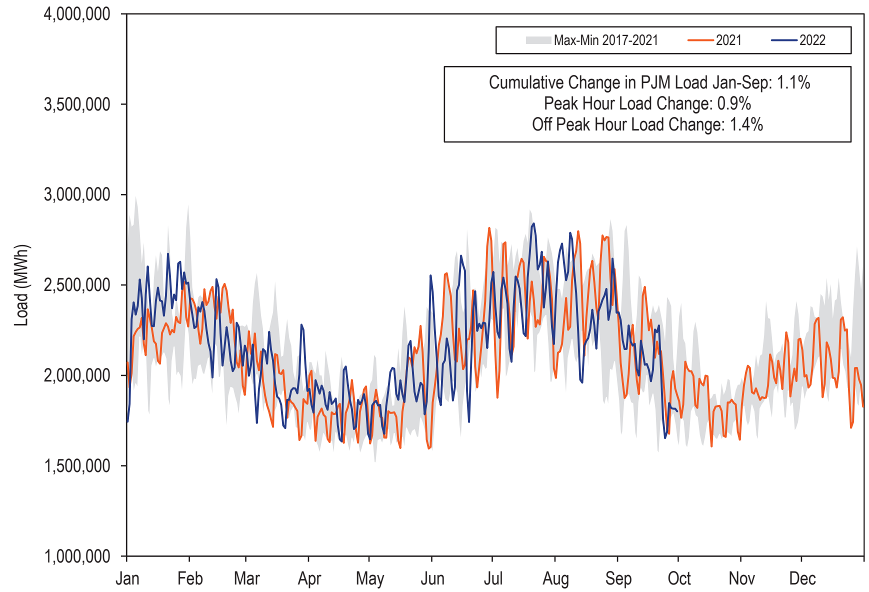


Figure 3-12 compares the real-time daily average load for 2021 through September 2022, with the historic five year range.

Figure 3-12 Real-time daily load: 2021 through September 2022



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in 2021 and the first nine months of 2022.[33] Cooling degree days increased 0.4 percent compared to the first nine months of 2021. Heating degree days increased 3.9 percent compared to the first nine months of 2021.

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

Table 3-8 Heating and cooling degree days: 2021 through September 2022

	2021		2022		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	816	0	983	0	20.5%	0.0%
Feb	822	0	693	0	(15.7%)	0.0%
Mar	405	0	445	0	9.9%	0.0%
Apr	203	8	256	5	25.9%	(41.1%)
May	77	82	21	101	(72.5%)	23.3%
Jun	0	283	0	260	0.0%	(8.1%)
Jul	0	360	0	406	0.0%	12.8%
Aug	0	374	0	345	0.0%	(7.6%)
Sep	0	158	15	153	0.0%	(3.1%)
Oct	57	44				
Nov	491	0				
Dec	524	0				
Jan-Sep	2,323	1,264	2,413	1,270	3.9%	0.4%

Figure 3-13 shows the real-time daily load and the weather normalized load in 2021 through September 2022.

Weather normalized load is calculated using the historic relationship between the daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-13 shows that the actual load was closer to the weather normalized load after a significant gap in 2020.

Figure 3-13 Real-time daily load and weather normalized load: 2020 through September 2022

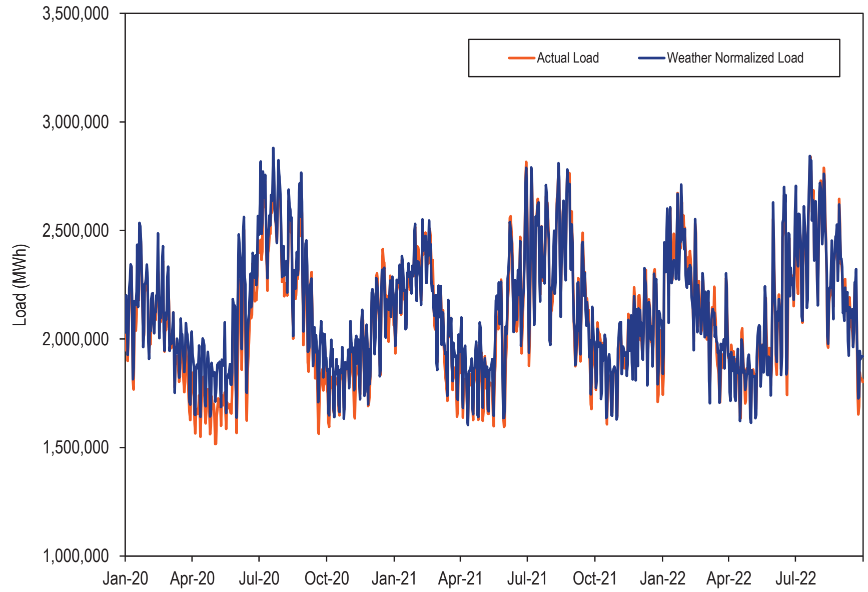


Table 3-9 compares the monthly actual load and the weather normalized load. Actual load was 0.2 percent lower than weather normalized load in the first nine months of 2022, actual load was 0.9 percent lower than weather normalized load in the first nine months of 2021, while actual load was 4.5 percent lower than weather normalized load in the first nine months of 2020.

Table 3-9 Actual load and weather normalized load: 2020 to September 2022

	2020			2021			2022		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	66,905,774	68,256,113	(2.0%)	69,303,496	69,689,108	(0.6%)	74,457,669	73,965,891	0.7%
Feb	61,717,353	62,471,212	(1.2%)	64,761,103	64,275,946	0.8%	62,556,707	61,833,819	1.2%
Mar	58,258,178	60,459,812	(3.6%)	60,002,018	61,459,726	(2.4%)	61,629,282	61,986,274	(0.6%)
Apr	50,864,950	55,116,626	(7.7%)	54,010,529	55,580,210	(2.8%)	55,444,404	55,267,453	0.3%
May	53,430,088	57,904,128	(7.7%)	57,460,157	59,183,412	(2.9%)	59,904,861	59,795,738	0.2%
Jun	63,666,037	67,406,845	(5.5%)	67,779,457	68,488,450	(1.0%)	66,521,445	67,334,205	(1.2%)
Jul	78,749,183	80,856,404	(2.6%)	74,409,489	74,488,509	(0.1%)	76,153,249	76,721,135	(0.7%)
Aug	72,425,029	74,173,773	(2.4%)	76,383,295	76,161,192	0.3%	74,839,426	74,939,704	(0.1%)
Sep	58,683,018	60,988,913	(3.8%)	62,305,584	62,675,810	(0.6%)	61,451,519	62,081,806	(1.0%)
Oct	55,061,813	56,572,150	(2.7%)	57,511,887	57,304,504	0.4%			
Nov	55,993,432	57,678,640	(2.9%)	59,887,527	59,557,389	0.6%			
Dec	67,232,280	67,074,317	0.2%	63,610,554	64,276,557	(1.0%)			
Jan - Sep	62,744,401	65,292,647	(3.9%)	65,157,236	65,778,040	(0.9%)	65,884,285	65,991,780	(0.2%)

Day-Ahead Demand

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.

The day-ahead hourly average demand in the first nine months of 2022, including DECs, UTCs and exports, increased by 5.6 percent from the first nine months of 2021, from 102,947 MWh to 108,685 MWh.

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

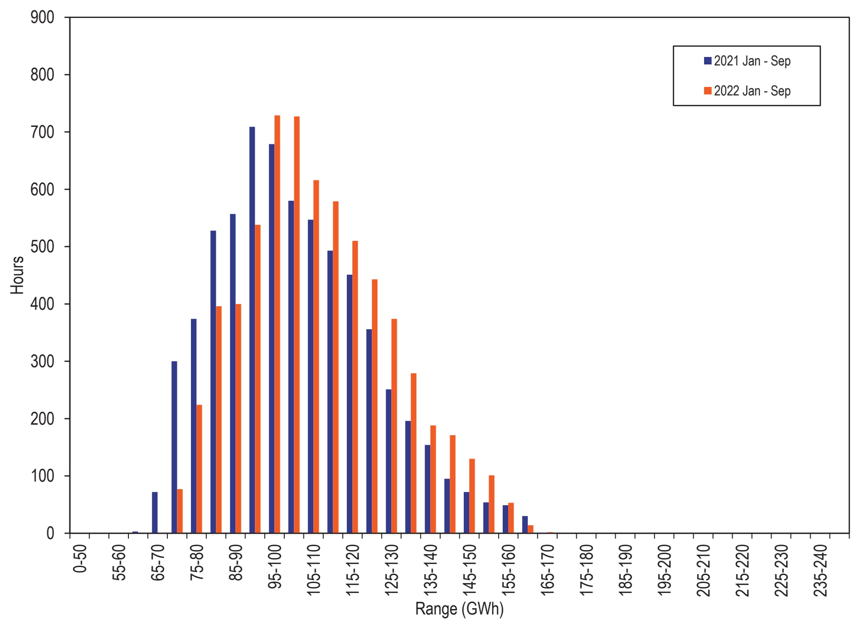
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-14 shows the hourly distribution of the day-ahead demand for the first nine months of 2021 and 2022.

Figure 3-14 Distribution of day-ahead demand plus exports: January through September, 2021 and 2022[34]



PJM Day-Ahead Average Demand

Table 3-10 shows day-ahead hourly average demand for the first nine months of 2001 through 2022. 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.

Table 3-10 Day-ahead hourly average demand and demand plus exports: January through September, 2001 through 2022

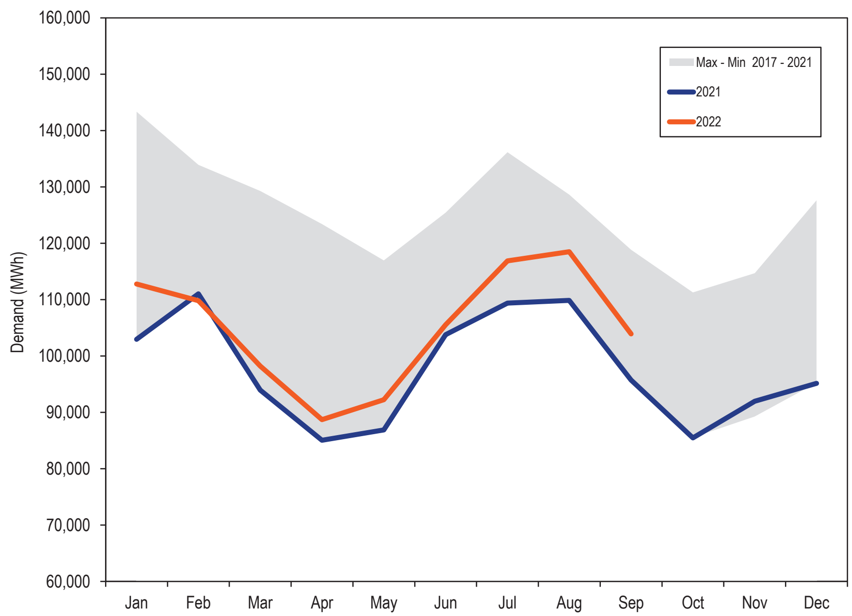
	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.3%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(3.9%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.0%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,555	19,789	116,912	19,957	(27.5%)	(16.1%)	(27.1%)	(15.2%)
2016	129,048	22,492	132,405	22,801	13.6%	13.7%	13.3%	14.2%
2017	128,453	20,002	131,572	20,158	(0.5%)	(11.1%)	(0.6%)	(11.6%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)
2020	109,850	19,762	113,188	20,089	(3.8%)	2.7%	(3.3%)	3.2%
2021	99,788	19,097	102,947	19,632	(9.2%)	(3.4%)	(9.0%)	(2.3%)
2022	105,195	18,664	108,685	18,945	5.4%	(2.3%)	5.6%	(3.5%)

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

PJM Day-Ahead Monthly Average Demand

Figure 3-15 compares the day-ahead monthly average demand including decrement bids and up to congestion transactions in 2021 and first nine months of 2022 with the historic five-year range.

Figure 3-15 Day-ahead monthly average demand plus exports: 2021 through September 2022



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for day-ahead and real-time demand for the first nine months of 2021 and 2022. The last two columns of Table 3-11 are day-ahead demand minus real-time demand. The first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load. The second column is the total day-ahead demand less the total real-time demand. The total physical day-ahead average load less the total physical real-time average load in the first nine months of 2022 decreased 285 MWh from the first nine months of 2021, from -1,175 MWh to -1,460 MWh. The total day-ahead average demand less the total real-time average demand in the first nine months of 2022 increased 4,288 MWh from the first nine months of 2021, from 8,201 MWh to 12,488 MWh.

Table 3-11 Day-ahead and real-time demand (MWh): January through September, 2021 and 2022

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Sep	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2021	86,967	1,373	4,134	7,315	3,158	102,947	89,515	94,746	(1,175)	8,201
	2022	88,395	660	5,237	10,904	3,490	108,685	90,514	96,196	(1,460)	12,488
Median	2021	85,016	1,390	3,724	7,159	2,942	100,404	87,428	92,143	(1,022)	8,260
	2022	85,663	435	5,023	10,221	3,551	106,272	87,952	94,072	(1,855)	12,200
Standard Deviation	2021	16,123	276	1,872	2,997	1,051	19,632	16,875	17,748	(476)	1,884
	2022	16,232	409	1,730	3,921	1,034	18,945	16,367	16,581	273	2,364
Peak Average	2021	95,552	1,536	4,845	8,511	3,380	113,824	98,034	103,626	(946)	10,198
	2022	96,476	714	5,721	11,866	3,574	118,351	98,384	104,158	(1,195)	14,193
Peak Median	2021	93,928	1,555	4,505	8,437	3,185	111,461	96,436	101,394	(953)	10,066
	2022	94,561	519	5,562	11,298	3,635	116,355	96,268	102,534	(1,188)	13,821
Peak Standard Deviation	2021	14,938	218	1,821	2,783	1,148	17,622	16,047	17,004	(891)	618
	2022	15,043	447	1,635	3,836	1,030	17,192	15,313	15,483	177	1,709
Off-Peak Average	2021	79,460	1,230	3,512	6,269	2,964	93,436	82,067	86,981	(1,376)	6,454
	2022	81,259	612	4,808	10,055	3,415	100,149	83,565	89,166	(1,694)	10,983
Off-Peak Median	2021	77,724	1,270	3,106	5,846	2,800	90,496	80,559	85,095	(1,565)	5,401
	2022	79,051	410	4,521	9,308	3,468	98,525	81,251	87,352	(1,790)	11,172
Off-Peak Standard Deviation	2021	13,091	240	1,685	2,779	916	16,032	13,773	14,436	(442)	1,596
	2022	13,703	365	1,698	3,797	1,031	16,111	13,945	14,166	124	1,945

Figure 3-16 shows the average cleared volumes of day-ahead and real-time demand in the first nine months of 2022. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-16 Day-ahead and real-time demand (Average hourly volumes): January through September, 2022

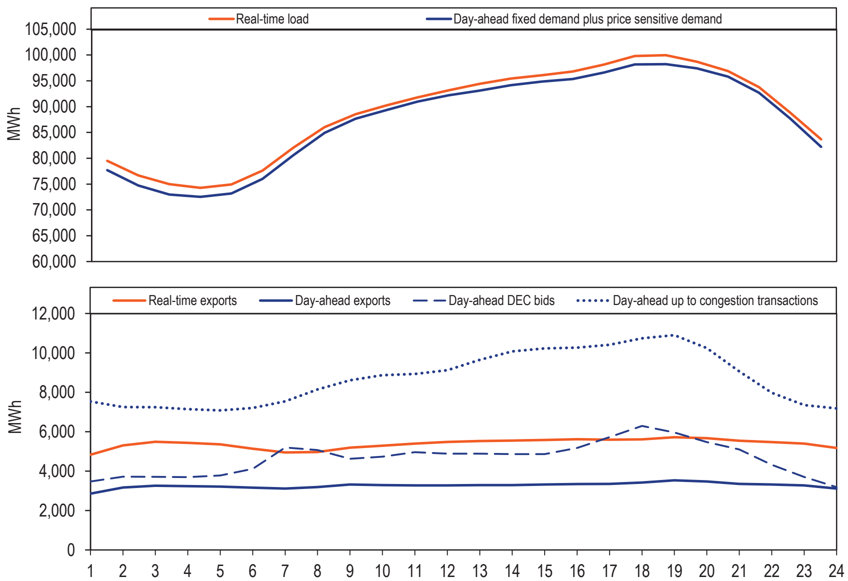
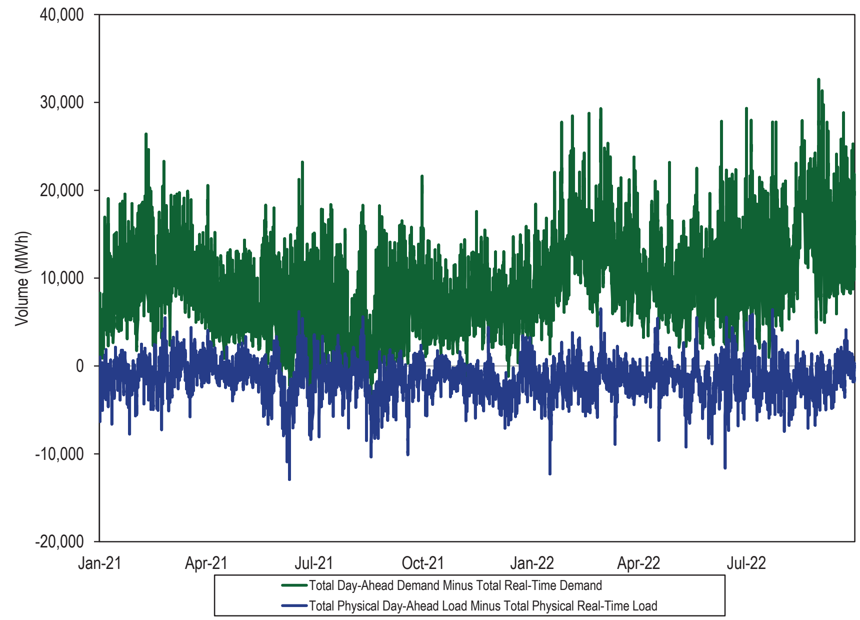


Figure 3-17 shows the difference between the day-ahead and real-time daily average demand in 2021 and the first nine months of 2022.

Figure 3-17 Difference between day-ahead and real-time daily average demand: 2021 through September 2022



Market Behavior

Generator Offers

Generators indicate their availability for commitment and dispatch in the day-ahead market through their offers. Commitment availability status is economic, must run, or unavailable. Dispatch availability status is defined by the difference between the economic minimum and maximum output levels. PJM will clear units that select must run status in the offer in the day-ahead market up to their economic minimum MW regardless of economics. Units may set their economic minimum MW equal to their economic maximum MW, also called block loading, or they may raise the economic minimum MW to a point between the actual economic minimum and the economic maximum. Must run units may commit at economic minimum and permit the balance to be dispatchable or block load the full output of the unit. If units select economic commitment status, the day-ahead market will commit them based on their offers.

The Must Run column in Table 3-12 is the economic minimum MW of units offering with must run commitment status. The Eco Min column in Table 3-12 is the economic minimum MW of units offering with economic commitment status. The dispatchable range in Table 3-12 is the percent of MW offered by price range, between the economic minimum MW and economic maximum MW for all available units. Some units, like wind and solar, offer a dispatchable range in the day-ahead market although their availability in real time is determined by the presence of sun and wind rather than economics.

Units may designate all or a portion of their capacity as emergency MW. Table 3-12 shows that 1.1 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW result from offer behavior that does not accurately represent the availability of the emergency MW in real time.

In the day-ahead market in the first nine months of 2022, 22.5 percent of MW were offered as must run, 31.7 percent of MW were offered as the economic minimum MW for dispatchable units, 44.8 percent of MW were offered as dispatchable, and 1.0 percent of MW were offered as emergency maximum MW.

In the first nine months of 2022, 47 percent of offer MW were priced below $50 per MWh, compared to 68 percent in the first nine months of 2021. Higher fuel prices, emissions prices, opportunity costs for emissions limited resources, and markup all contributed to higher offers.

Table 3-12 Dispatchable status of day-ahead energy offers: January through September, 2022

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	8.0%	35.8%	0.0%	3.2%	21.5%	15.2%	6.2%	6.7%	3.1%	0.2%	0.0%	0.0%	0.2%	56.1%
CT	0.5%	56.4%	0.0%	0.0%	1.8%	6.2%	6.8%	13.9%	9.1%	2.2%	0.6%	0.1%	2.5%	40.6%
Diesel	0.0%	92.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.0%	0.0%	0.0%	0.0%	0.0%	8.0%
Hydro	85.4%	0.0%	14.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.6%
Nuclear	88.8%	6.8%	3.1%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%
Solar	12.5%	1.7%	79.4%	1.0%	0.1%	0.6%	1.1%	3.0%	0.5%	0.0%	0.0%	0.0%	0.0%	85.8%
Steam - Coal	25.8%	25.3%	0.0%	3.0%	15.5%	9.3%	8.7%	7.7%	1.5%	1.0%	0.0%	0.1%	2.2%	46.8%
Steam - Other	5.2%	24.0%	1.1%	1.4%	4.0%	7.0%	13.2%	19.5%	20.0%	4.2%	0.0%	0.0%	0.6%	70.3%
Wind	4.5%	0.8%	85.6%	4.8%	2.2%	0.8%	0.4%	0.7%	0.3%	0.0%	0.0%	0.0%	0.0%	94.7%
Other	18.0%	46.7%	4.7%	0.1%	4.6%	5.0%	0.3%	1.9%	14.0%	1.2%	0.2%	0.0%	3.5%	31.9%
All Units	22.5%	31.7%	2.5%	2.0%	10.8%	8.8%	6.2%	8.3%	5.0%	1.1%	0.1%	0.0%	1.0%	44.8%

Hourly Offers and Intraday Offer Updates

All participants may make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Table 3-13 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In the first nine months of 2022, an average of 339 units per day made hourly offers, an increase of 16 units from the first nine months of 2021. In the first nine months of 2022, 484 units opted in for intraday offer updates, an increase of 56 units from the first nine months of 2021. In the first nine months of 2022, an average of 133 units made intraday offer updates each day, an increase of three units from the first nine months of 2021.

Table 3-13 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2021 and 2022

	Fuel Type	2021 (Jan-Sep)	2022 (Jan-Sep)	Difference
Hourly Offers	Natural Gas	301	311	10
	Other Fuels	22	28	6
	Total	323	339	16
Opt In	Natural Gas	360	391	31
	Other Fuels	68	93	25
	Total	428	484	56
Intraday Offer Updates	Natural Gas	124	126	2
	Other Fuels	6	7	1
	Total	130	133	3
Total Units with nonzero offers		987	987	0

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[35] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement.

Solar, wind, landfill gas, hydro and batteries can satisfy the must offer requirement by self scheduling or offering as dispatchable. There is no defined amount of capacity that these resources must offer. The must offer requirement is thus not applied to these intermittent resource types and compliance is not enforceable.

The current enforcement of the ICAP must offer requirement is inadequate.[36] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked in a systematic way to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are never reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd.

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.

The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources.

Table 3-14 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first nine months of 2022. On average for all

35 OA Schedule 1 § 1.10.1A(d).

36 PJM compares the data submitted in eDART to the data submitted in Markets Gateway using the eDART Gen Checkout. Generators are supposed to acknowledge their Gen Checkout reports. Manual 10 and the eDART User Guide do not specify what acknowledging the Gen Checkout report means, any requirements to acknowledge the Gen Checkout report or any consequences for not doing so. Gen Checkout is also only triggered if generators fail by more than defined thresholds.

hours, 1,703 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 3,058 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that triggered scarcity pricing in the first nine months of 2022 and larger than most supply contingencies that led to synchronized reserve events in the first nine months of 2022. Unavailable capacity was highest in the summer months when ambient derates are most common.

Table 3-14 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through September 2022

Month	90th Percentile	Average	10th Percentile
Jan-22	1,595	927	434
Feb-22	1,632	1,034	471
Mar-22	3,463	2,145	868
Apr-22	1,809	1,255	763
May-22	3,300	1,972	810
Jun-22	2,880	1,712	925
Jul-22	3,424	2,682	1,938
Aug-22	3,137	2,372	1,656
Sep-22	2,057	1,129	0
2022	3,058	1,703	631

The outage data reported in eGADS do not exactly match the energy market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[37]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[38]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[39] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation. The capacity performance rules in the capacity market provide incentives for such output during PAI.

Table 3-15 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in June 2022, 10 percent of hours had maximum emergency MW greater than or equal to 5,955 MW while 10 percent of hours had maximum emergency MW less than 3,639 MW. The hourly average, in the first nine months of 2022, was 2,526 MW offered as maximum emergency, 9.6 percent higher than in the first nine months of 2021.

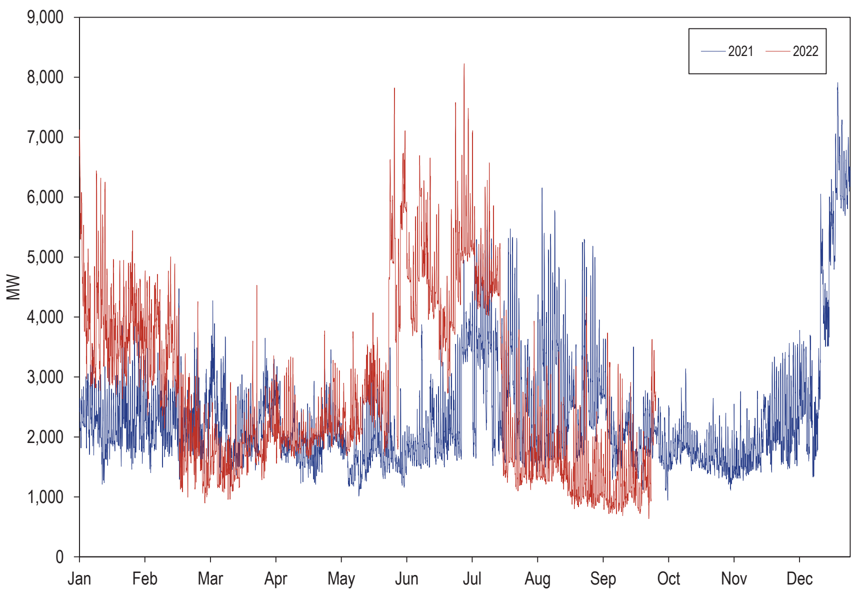
37 See 151 FERC ¶ 61,208 at P 476 (2015).
38 OA Schedule 1 § 1.10.1A(d).
39 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Table 3-15 Maximum emergency MW by month: January through September 2022

Month	90th Percentile	Average	10th Percentile
Jan-22	4,905	3,946	3,029
Feb-22	4,171	2,828	1,478
Mar-22	2,211	1,698	1,191
Apr-22	2,704	2,118	1,772
May-22	4,623	2,797	1,905
Jun-22	5,955	4,674	3,639
Jul-22	5,484	3,741	1,344
Aug-22	2,518	1,593	978
Sep-22	2,354	1,390	810
2022	4,346	2,526	1,404

Figure 3-18 shows maximum emergency MW by hour in 2021 and the first nine months of 2022. The increase in maximum emergency MW in December 2021 through February 2022 and again in June 2022 was mainly due to coal availability, consumables inventory shortages and environmentally limited units.

Figure 3-18 Maximum Emergency MW by hour: 2021 and January through September, 2022



Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.[40]

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first nine months of 2022. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[41] Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price

40 See 175 FERC ¶ 61,231 (2021).
41 Nuclear, wind, solar and hydro units are not subject to parameter limits.

schedules. Table 3-16 shows that 30.9 percent of unit hours for units that failed the TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. For effective market power mitigation there would be zero units that fail the TPS test committed with parameters less flexible than their cost-based schedules.

Table 3-16 Parameter mitigation for units failing TPS test: January through September 2022

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	21,651	30.9%
Committed on price schedule as flexible as cost	3,259	4.7%
Total committed on price schedule without parameter limits	24,910	35.6%
Committed on cost (cost capped)	43,031	61.5%
Committed on price PLS	2,042	2.9%
Total committed on PLS schedules (cost or price PLS)	45,073	64.4%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in regions where a cold weather alert or a hot weather alert was declared in the first nine months of 2022. PJM declared cold weather alerts on seven days and hot weather alert days on 31 days in the first nine months of 2022.[42] The analysis includes units with technologies that are subject to parameter limits, with a CP commitment, in the zones where the cold or hot weather alerts were declared. Table 3-17 shows that 18.4 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.[43] Effective market power mitigation would result in zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

Table 3-17 Parameter mitigation during weather alerts: January through September, 2022

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	21,651	18.4%
Committed on price schedule as flexible as PLS	3,259	2.8%
Total committed on price schedule without parameter limits	24,910	21.2%
Committed on cost (cost capped)	4,707	4.0%
Committed on price PLS	87,834	74.8%
Total committed on PLS schedules (cost or price PLS)	92,541	78.8%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing emergency conditions. This would require that PJM apply the full set of approved unit specific parameters to a resource that offers any inflexible parameter under these conditions. The selection of the lowest cost offer, based on the financial parameters, would follow the application of PLS parameters.

Currently, PJM commits units on either a cost-based or a price-based schedule. For example, selecting a price-based schedule means selecting the combination of all the operating and financial parameters of such schedule.

42 *2022 Quarterly State of the Market Report for PJM: January through September*, Section 3: Energy Market, at Emergency Procedures.
43 Nuclear, wind, solar and hydro units are not subject to parameter limits.

The financial parameters and the operating parameters must be addressed separately. This approach would simplify the schedule structure implemented in PJM and would allow PJM to effectively mitigate inflexible operating parameters. The simplified modelling would speed the processing time of the day-ahead market, facilitating the implementation of enhanced combined cycle modelling.

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.

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. PJM would separately mitigate the operating parameters and the financial parameters of the offers (incremental offer, startup cost, and no load cost).[44]

Parameter Limits

Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. The unit specific parameter limits for capacity performance resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance resources.

44 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

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

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[45] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-18 shows, for the delivery year beginning June 1, 2022, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

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

Table 3-18 Adjusted unit specific parameter limit statistics: 2022/2023 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	120	37	23.6%
Frame CT	162	105	39.3%
Combined Cycle	89	31	25.8%
Reciprocating Internal Combustion Engines	66	4	5.7%
Solid Fuel NUG	34	6	15.0%
Oil and Gas Steam	9	13	59.1%
Subcritical Coal Steam	5	54	91.5%
Supercritical Coal Steam	1	36	97.3%
Pumped Storage	7	1	12.5%

Real-Time Values

The Commission rejected PJM's proposed revisions to add RTV rules to the tariff in an order issued on May 28, 2021. In its order, the Commission recognized that RTVs can be used to exercise market power by withholding generation and avoiding market power mitigation.[46]

The real-time values submittal process was never defined in the PJM Operating Agreement. The process was defined only in PJM Manual 11. While there are a number of options for providing real-time unit status to PJM operators, PJM created a mechanism for the submission of such values called real-time values (RTVs). Unlike parameter exceptions, the use of real-time values made a unit ineligible for make whole payments, unless the market seller could justify such operation based on an actual constraint.[47] In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

46 175 FERC ¶ 61,171 (2021).
47 See OA Schedule 1 § 3.2.3(e).

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.[48]

Beginning August 1, 2021, PJM provides guidance to market sellers that it will no longer accept real-time value submissions for economic reasons, such as due to choosing not to staff a unit. In its order to show cause issued on June 17, 2021, the Commission stated its concern that "the PJM Tariff appears to be unjust and unreasonable because it fails to contain provisions governing what happens if a seller is unable to meet its unit-specific parameters in real time".[49] In its response to the Commission's order, PJM proposed tariff updates to allow generators to submit temporary exceptions during the operating day.[50] These rules require market sellers to justify that the request is based on a physical and actual constraint by submitting supporting documentation within three business days, consistent with the existing temporary parameter exception process. However, the September 15th Response proposes no consequences to market sellers who do not adhere to the proposed tariff defined rules on what is considered a valid justification for temporary exceptions.

Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses temporary parameter exceptions or RTVs to communicate the longer time to start to PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no defined consequence, while other similarly situated units incur the costs associated with meeting their obligations. Such withholding is an exercise of market power. If market sellers instead represent that they are able to meet the time to start parameters, but the unit is not staffed or the unit is not equipped with remote start

48 175 FERC ¶ 61,171 at P 36 (2021).
49 175 FERC ¶ 61,231 at P 17 (2021).
50 PJM. "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021)("September 15th Response").

capability to meet its unit specific limits, there is no defined consequence for misrepresenting the unit's capability. In its September 15 Response, PJM proposes no explicit defined penalties for such behavior.

Units that override their turn down ratio (economic maximum divided by economic minimum) either use Real-Time Values or PJM's fixed gen flag, which functions identically to a real-time value.[51] These resources operate on their parameter limited schedules but override their output limit parameters with no consequence. The only difference between a Real-Time Value to override the turn down ratio parameter and the fixed gen flag is that the fixed gen resources receive uplift payments. These resources receive inefficient levels of uplift payments when they have market power. The September 15 Response does not address unstaffed units that refuse to meet their notification time or units that refuse to perform to their turn down ratio parameter by using fixed gen.

There are two options to address the real-time exceptions issue. The immediate option is to clearly define acceptable and unacceptable reasons for requesting a real-time exception. In the case of unacceptable reasons, the unit would not be paid a portion of its otherwise applicable capacity market revenues, e.g. the daily value, if it included the modified parameter values in its offer. 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.

The better option, consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, is to not pay any capacity resources an appropriate portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that Capacity Performance resources are paid for their capacity only when it meets their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[52]

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[53] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[54] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[55]

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

51 PJM Markets Gateway User Guide, Section 6.9: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 41, <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.

52 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.

53 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).

54 *Id* at P 439.

55 *Id* at P 440.

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

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

The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the reference resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and recently, during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. Table 3-19 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first nine months of 2022, there were 72 units in PJM, with a total installed capacity of 8,223 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions. The increase in the number of requests for 24 hour minimum run times in 2021 and 2022 was a result of the increased issuance of restrictions by pipelines, including summer and winter months.

Table 3-19 Units with 24 hour minimum run times due to gas pipeline restrictions: January through September, 2018 through 2022

Year (Jan - Sep)	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	25	3,627
2019	37	5,616
2020	8	3,448
2021	61	7,513
2022	72	8,223

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

Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market, and such offers and bids may be marginal.

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. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[56] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[57] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2022.

56 162 FERC ¶ 61,139 (2018).

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

Figure 3-19 Day-ahead aggregate supply curves: 2022 example day

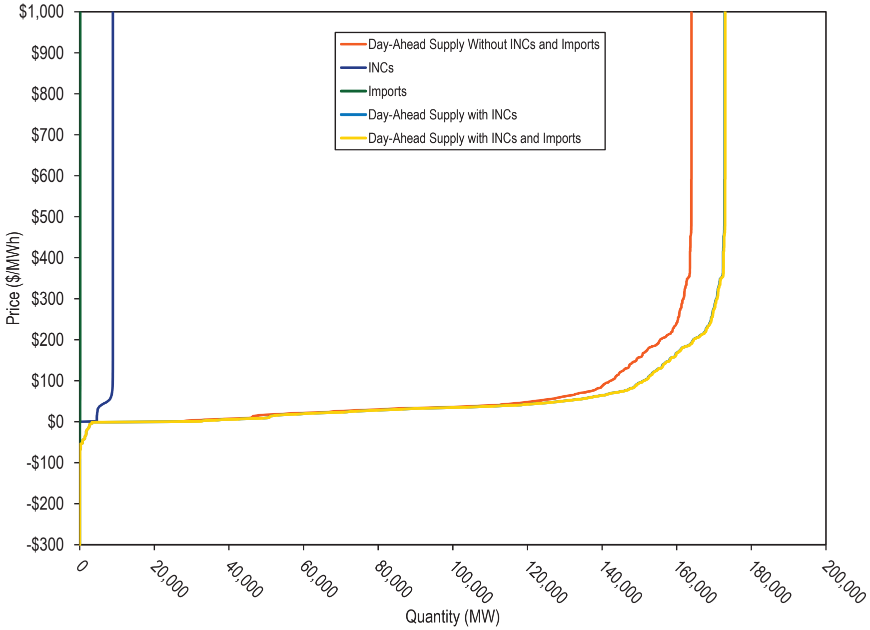


Table 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2021 and the first nine months of 2022. The hourly average submitted increment offer MW increased by 33.9 percent and cleared increment MW increased by 50.5 percent in the first nine months 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.

Table 3-20 Average hourly number of cleared and submitted INCs and DECs by month: January 2021 through September 2022

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2021	Jan	2,208	6,221	259	1,068	3,916	10,076	297	1,194
2021	Feb	2,078	5,476	264	972	5,123	11,556	280	1,303
2021	Mar	2,838	6,524	273	947	4,406	10,063	280	1,149
2021	Apr	3,053	6,998	297	974	3,569	9,188	223	928
2021	May	2,431	6,036	259	885	3,415	8,363	187	862
2021	Jun	1,898	5,290	180	726	4,971	10,854	197	1,024
2021	Jul	2,244	5,797	211	820	3,810	9,054	165	842
2021	Aug	1,788	4,944	202	816	4,016	9,483	182	1,032
2021	Sep	2,226	5,984	252	899	4,080	10,290	276	1,214
2021	Oct	1,993	5,465	294	956	4,079	10,372	308	1,315
2021	Nov	2,636	6,324	344	1,074	3,812	9,446	304	1,224
2021	Dec	2,344	5,813	271	895	5,354	11,290	369	1,191
2021	Annual	2,312	5,907	259	919	4,206	9,991	256	1,105
2022	Jan	2,898	7,135	308	1,069	6,513	14,228	375	1,559
2022	Feb	3,743	8,639	359	1,216	6,078	13,359	348	1,370
2022	Mar	4,072	9,403	337	1,143	5,579	12,511	256	1,074
2022	Apr	3,909	8,696	342	1,069	3,833	11,008	196	1,026
2022	May	3,588	8,381	319	1,029	4,960	12,441	247	1,072
2022	Jun	3,467	7,708	249	909	4,719	11,482	234	1,032
2022	Jul	3,060	7,249	266	1,068	4,451	10,703	192	976
2022	Aug	3,112	6,696	259	973	4,889	11,092	241	997
2022	Sep	3,352	7,280	257	1,109	6,157	11,806	287	1,003
2022	Jan-Sep	3,463	7,902	299	1,064	5,237	12,063	264	1,122

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2021 and the first nine months of 2022. 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.

Table 3-21 Average hourly cleared and submitted up to congestion bids by month: January 2021 through September 2022

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2021	Jan	7,277	20,412	546	1,062
2021	Feb	10,354	23,732	691	1,227
2021	Mar	8,776	24,571	548	1,087
2021	Apr	6,770	21,293	495	1,033
2021	May	6,976	20,674	585	1,164
2021	Jun	7,163	17,808	621	1,132
2021	Jul	6,743	16,386	572	1,041
2021	Aug	5,366	13,542	435	857
2021	Sep	6,659	16,579	471	1,138
2021	Oct	5,421	15,732	414	1,071
2021	Nov	6,761	18,741	490	1,106
2021	Dec	6,629	19,107	503	1,081
2021	Annual	7,050	19,014	530	1,082
2022	Jan	8,268	28,791	478	1,322
2022	Feb	11,908	31,383	632	1,452
2022	Mar	10,921	34,887	521	1,366
2022	Apr	9,030	37,400	440	1,342
2022	May	8,616	34,312	438	1,277
2022	Jun	10,213	31,573	520	1,305
2022	Jul	11,009	35,453	624	1,669
2022	Aug	15,007	48,449	756	2,143
2022	Sep	13,259	48,064	853	2,245
2022	Jan-Sep	10,904	36,735	584	1,570

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2021 through September 2022. In the first nine months of 2022, the average hourly submitted import transaction MW increased by 34.5 percent and the average hourly cleared import transaction MW increased by 43.9 percent compared to the first nine months of 2021. In the first nine months of 2022, the average hourly submitted export transaction MW increased by 11.1 percent and the average hourly cleared export transaction MW increased by 11.2 percent compared to the first nine months of 2021.

Table 3-22 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2021 through September 2022

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2021	Jan	389	408	4	4	2,854	2,862	30	30
2021	Feb	267	285	3	4	4,581	4,658	41	42
2021	Mar	250	266	2	3	2,493	2,542	27	28
2021	Apr	214	249	3	3	2,364	2,376	24	24
2021	May	217	268	2	3	2,255	2,279	21	21
2021	Jun	155	177	2	2	3,463	3,489	30	30
2021	Jul	139	180	2	3	3,690	3,713	32	33
2021	Aug	116	158	2	3	3,619	3,641	31	31
2021	Sep	108	136	2	2	3,231	3,251	30	31
2021	Oct	103	133	2	3	2,478	2,513	24	25
2021	Nov	169	189	3	3	2,307	2,314	20	20
2021	Dec	118	135	2	2	4,033	4,055	32	33
2021	Annual	185	214	2	3	3,105	3,132	28	29
2022	Jan	295	322	4	5	4,349	4,360	35	36
2022	Feb	271	298	4	4	4,639	4,647	37	37
2022	Mar	169	196	3	3	3,822	3,842	27	27
2022	Apr	247	269	4	4	2,085	2,110	19	20
2022	May	428	441	5	5	2,521	2,566	21	21
2022	Jun	310	320	3	3	3,084	3,118	31	31
2022	Jul	268	283	3	3	3,217	3,265	31	31
2022	Aug	308	316	3	3	4,010	4,046	32	32
2022	Sep	356	396	2	3	3,830	3,870	29	30
2022	Jan-Sep	295	316	3	4	3,500	3,529	29	29

Table 3-23 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 2021 through September 2022.

Table 3-23 Type of day-ahead marginal resources: January 2021 through September 2022

	2021						2022					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	23.1%	0.1%	35.7%	24.2%	16.9%	0.0%	19.6%	0.1%	37.9%	26.0%	16.4%	0.0%
Feb	20.3%	0.4%	45.1%	23.1%	11.1%	0.0%	13.2%	0.1%	43.5%	23.8%	19.3%	0.0%
Mar	18.9%	0.1%	33.9%	26.5%	20.6%	0.0%	14.9%	0.1%	41.8%	18.9%	24.3%	0.0%
Apr	19.4%	0.2%	34.4%	21.6%	24.5%	0.0%	19.4%	0.3%	36.0%	17.6%	26.6%	0.0%
May	20.6%	0.2%	35.5%	24.5%	19.1%	0.0%	15.9%	0.4%	41.6%	21.6%	20.4%	0.0%
Jun	21.3%	0.2%	35.8%	30.4%	12.3%	0.0%	14.9%	0.2%	47.7%	22.2%	14.9%	0.0%
Jul	17.6%	0.3%	39.4%	28.8%	13.8%	0.0%	14.9%	0.3%	50.8%	19.9%	14.0%	0.0%
Aug	18.4%	0.5%	37.2%	30.5%	13.4%	0.0%	14.6%	0.2%	53.3%	17.9%	13.9%	0.0%
Sep	31.9%	0.4%	25.6%	24.6%	17.5%	0.0%	20.0%	0.5%	50.0%	16.3%	13.2%	0.0%
Oct	32.0%	0.3%	27.2%	25.0%	15.3%	0.0%						
Nov	33.9%	0.2%	26.4%	21.9%	17.5%	0.0%						
Dec	34.0%	0.2%	26.7%	24.3%	14.8%	0.0%						
Annual	25.2%	0.3%	32.7%	25.2%	16.6%	0.0%	16.5%	0.2%	44.1%	20.8%	18.3%	0.0%

Figure 3-20 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through September 2022.

Figure 3-20 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through September 2022

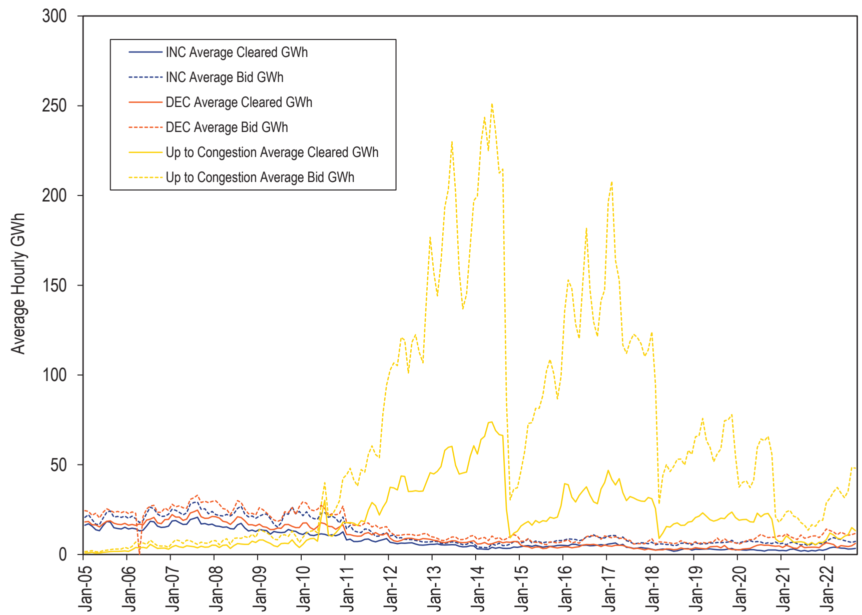
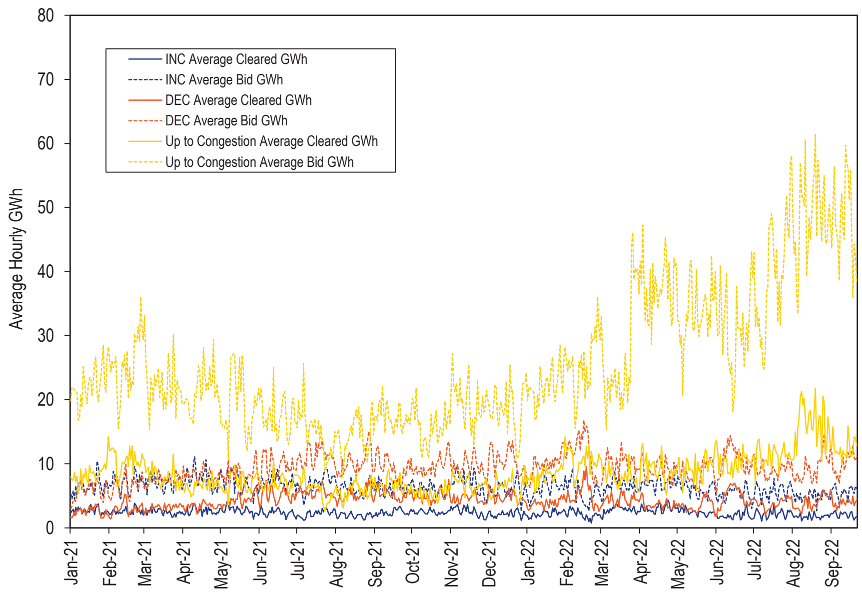


Figure 3-21 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2021 through September 2022.

Figure 3-21 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2021 through September 2022



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers that primarily take physical positions in PJM markets. Financial entities include banks and hedge funds that primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries. Financial entities' share of submitted and cleared MWh of all three virtual products increased in the first nine months of 2022 compared to 2021.

Table 3-24 shows, in the first nine months of 2021 and 2022, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-24 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2021 and 2022

	2021 (Jan-Sep)				2022 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	93,549,221	90.5%	34,782,210	82.4%	120,399,637	92.1%	49,331,687	86.6%
Physical	9,834,550	9.5%	7,420,198	17.6%	10,386,777	7.9%	7,655,730	13.4%
Total	103,383,771	100.0%	42,202,408	100.0%	130,786,414	100.0%	56,987,417	100.0%

Table 3-25 shows, in the first nine months of 2021 and 2022, the total up to congestion bid and cleared MWh by type of parent organization. Up to congestion bids submitted by financial entities more than doubled in the first nine months of 2022 compared to the first nine months of 2021, from 113 million MWh to 231 million MWh, while up to congestion bids submitted by physical entities decreased during the same period. Financial entities submitted 95.8 percent of all up to congestion bids, up from 89.1 percent, and 92.5 percent of all cleared up to congestion bids, up from 86.2 percent, in the first nine months of 2022, compared to the first nine months of 2021.

Table 3-25 Up to congestion transactions by type of parent organization (MWh): January through September 2021 and 2022

	2021 (Jan-Sep)				2022 (Jan-Sep)			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	113,251,705	89.1%	41,321,149	86.2%	230,599,487	95.8%	66,092,161	92.5%
Physical	13,875,893	10.9%	6,596,998	13.8%	10,049,927	4.2%	5,343,190	7.5%
Total	127,127,598	100.0%	47,918,147	100.0%	240,649,414	100.0%	71,435,351	100.0%

Table 3-26 shows, in the first nine months of 2021 and 2022, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-26 Import and export transactions by type of parent organization (MWh): January through September 2021 and 2022

		2021 (Jan-Sep)		2022 (Jan-Sep)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	8,180,387	37.4%	7,022,447	32.4%
	Physical	13,721,339	62.6%	14,658,828	67.6%
	Total	21,901,727	100.0%	21,681,275	100.0%
Real-Time	Financial	10,993,824	28.2%	10,977,572	25.9%
	Physical	28,033,310	71.8%	31,403,507	74.1%
	Total	39,027,133	100.0%	42,381,079	100.0%

Table 3-27 shows increment offers and decrement bids by the top 10 locations in the first nine months of 2021 and 2022.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): January through September, 2021 and 2022

2021 (Jan-Sep)					2022 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	123,315	5,431,289	5,554,604	MISO	INTERFACE	109,422	5,378,644	5,488,066
WESTERN HUB	HUB	794,251	1,444,471	2,238,722	WESTERN HUB	HUB	1,348,456	4,003,340	5,351,797
LINDENVFT	INTERFACE	44,774	1,357,611	1,402,385	SOUTH	INTERFACE	969,099	1,149,934	2,119,033
DOM_RESID_AGG	RESIDUAL METERED EDC	122,332	1,157,711	1,280,043	AEP-DAYTON HUB	HUB	511,868	1,311,066	1,822,935
AEP-DAYTON HUB	HUB	284,262	805,973	1,090,235	NYIS	INTERFACE	665,531	1,080,592	1,746,123
BGE_RESID_AGG	RESIDUAL METERED EDC	152,486	884,510	1,036,996	LINDENVFT	INTERFACE	21,785	1,715,993	1,737,777
NYIS	INTERFACE	479,511	498,333	977,844	N ILLINOIS HUB	HUB	943,107	739,791	1,682,897
N ILLINOIS HUB	HUB	317,981	509,645	827,627	DOM_RESID_AGG	RESIDUAL METERED EDC	77,026	1,605,408	1,682,434
AEPOHIO_RESID_AGG	RESIDUAL METERED EDC	129,388	609,672	739,060	NEW JERSEY HUB	HUB	812,284	645,670	1,457,955
COMED_RESID_AGG	RESIDUAL METERED EDC	277,323	414,560	691,883	CHICAGO GEN HUB	HUB	863,426	428,419	1,291,845
Top ten total		2,725,623	13,113,775	15,839,398			6,322,004	18,058,857	24,380,862
PJM total		15,122,868	27,079,541	42,202,408			22,682,963	34,304,453	56,987,417
Top ten total as percent of PJM total		18.0%	48.4%	37.5%			27.9%	52.6%	42.8%

Table 3-28 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in the first nine months of 2021 and 2022. Total profits for up to congestion transactions in the first nine months of 2022 were $111.6 million, an increase of 447 percent compared to profits of $20.4 million in the first nine months of 2021. The top 10 paths made up a larger share of profits in the first nine months of 2022, 26.5 percent, compared to 18.1 percent in the first nine months of 2021.[58] The UTCs from DOMINION HUB to DOM RESID AGG constituted 14 percent of all UTC profits in the first nine months of 2022. Congestion in the Dominion zone in the first nine months of 2022, especially in the summer months, resulted from relatively higher gas prices in Virginia compared to the rest of the PJM footprint and from increased data center load in Northern Virginia.

58 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through September, 2021 and 2022[59]

2021 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Revenue
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,309,469	$1,330,625	($201,191)	$450,567
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,478,636	$1,352,735	($317,600)	$623,287
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,086,379	$584,279	$226,717	$412,501
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	836,590	($703,909)	$1,264,387	$101,674
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	792,662	$682,551	$297,142	$741,828
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	787,045	$911,333	($486,304)	$176,749
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	678,607	$526,016	($36,076)	$289,766
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	656,698	$336,328	$481,008	$565,442
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	646,078	($389,539)	$837,292	$241,194
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	629,077	$263,697	$43,535	$41,868
Top ten total				9,901,240	$4,894,117	$2,108,910	$3,644,875
PJM total				91,318,971	$18,584,946	$20,104,068	$20,402,829
Top ten total as percent of PJM total				10.8%	26.3%	10.5%	17.9%
2022 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Revenue
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	3,882,469	$7,979,274	$10,234,119	$15,682,875
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,463,635	$2,780,522	$414,449	$2,169,319
MISO	INTERFACE	SOUTH	INTERFACE	1,854,657	$5,016,211	($35,062)	$3,792,772
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	1,498,160	$4,417,207	($1,302,029)	$2,401,097
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,251,972	$5,510,940	($3,574,381)	$1,300,849
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,141,751	$873,915	$322,076	$690,559
MISO	INTERFACE	DEOK_RESID_AGG	AGGREGATE	907,069	$2,307,500	($986,705)	$1,062,178
CHICAGO HUB	HUB	OHIO HUB	HUB	877,089	($845,112)	$2,738,719	$1,552,347
ATSI GEN HUB	HUB	OVEC_RESID_AGG	AGGREGATE	876,452	$1,177,719	($364,285)	$551,864
WESTERN HUB	HUB	DOMINION HUB	HUB	860,457	$3,867,936	($2,221,169)	$1,474,968
Top ten total				15,613,711	$33,086,112	$5,225,732	$30,678,827
PJM total				71,435,351	$119,910,808	$24,499,824	$111,606,607
Top ten total as percent of PJM total				21.9%	27.6%	21.3%	27.5%

59 The columns "Source Revenue" and "Sink Revenue" are totals before uplift charges are subtracted. The column "UTC Profit" includes uplift charges, in addition to the source and sink revenue, and so is less than the sum of the revenue from each side of the transaction.

Table 3-29 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2021 through September 2022. Since November 1, 2020, when up to congestion transactions first became subject to uplift charges, there has been a decrease in the average number of paths with submitted and cleared bids along with the decrease in the volume of submitted and cleared up to congestion MW. The average number of submitted source-sink pairs increased slightly from a daily average of 1,368 source-sink pairs submitted in 2021 to 1,504 pairs on average per day in the first nine months of 2022. The average number of cleared source-sink pairs also increased slightly from 1,200 on average per day in 2021 to 1,272 per day in the first nine months of 2022.

Table 3-29 Number of offered and cleared source and sink pairs: January 2021 through September 2022

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2021	Jan	1,286	1,470	1,132	1,302
2021	Feb	1,303	1,514	1,210	1,449
2021	Mar	1,314	1,542	1,189	1,386
2021	Apr	1,309	1,559	1,146	1,388
2021	May	1,329	1,540	1,176	1,395
2021	Jun	1,291	1,412	1,161	1,289
2021	Jul	1,299	1,466	1,161	1,294
2021	Aug	1,403	1,622	1,221	1,469
2021	Sep	1,503	1,610	1,272	1,427
2021	Oct	1,461	1,567	1,212	1,349
2021	Nov	1,501	1,603	1,304	1,426
2021	Dec	1,421	1,582	1,216	1,345
2021	Annual	1,368	1,541	1,200	1,377
2022	Jan	1,398	1,555	1,228	1,405
2022	Feb	1,501	1,633	1,296	1,488
2022	Mar	1,392	1,609	1,178	1,449
2022	Apr	1,415	1,513	1,174	1,274
2022	May	1,417	1,525	1,181	1,291
2022	Jun	1,488	1,644	1,253	1,458
2022	Jul	1,551	1,703	1,305	1,478
2022	Aug	1,689	1,782	1,394	1,521
2022	Sep	1,686	1,855	1,436	1,646
2022	Jan-Sep	1,504	1,647	1,272	1,446

Table 3-30 and Figure 3-22 show total cleared up to congestion transactions and share of the top 10 up to congestion paths by transaction type (import, export, or internal) in the first nine months of 2021 and 2022. Total cleared up to congestion transactions increased by 49.1 percent from 47.9 million MWh in the first nine months of 2021 to 71.4 million MWh in the first nine months of 2022. Internal up to congestion transactions in the first nine months of 2022 were 76.4 percent of all up to congestion transactions, compared to 81.3 percent in the first nine months of 2021.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through September, 2021 and 2022

	2021 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,162,777	2,433,589	497,399	9,650,105	14,743,870
PJM total (MW)	4,164,644	4,180,434	626,144	38,946,924	47,918,146
Top ten total as percent of PJM total	51.9%	58.2%	79.4%	24.8%	30.8%
PJM total as percent of all up to congestion transactions	8.7%	8.7%	1.3%	81.3%	100.0%
	2022 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,785,703	3,389,921	2,489,480	14,552,996	25,218,101
PJM total (MW)	7,529,620	6,710,156	2,607,480	54,588,096	71,435,351
Top ten total as percent of PJM total	63.6%	50.5%	95.5%	26.7%	35.3%
PJM total as percent of all up to congestion transactions	10.5%	9.4%	3.7%	76.4%	100.0%

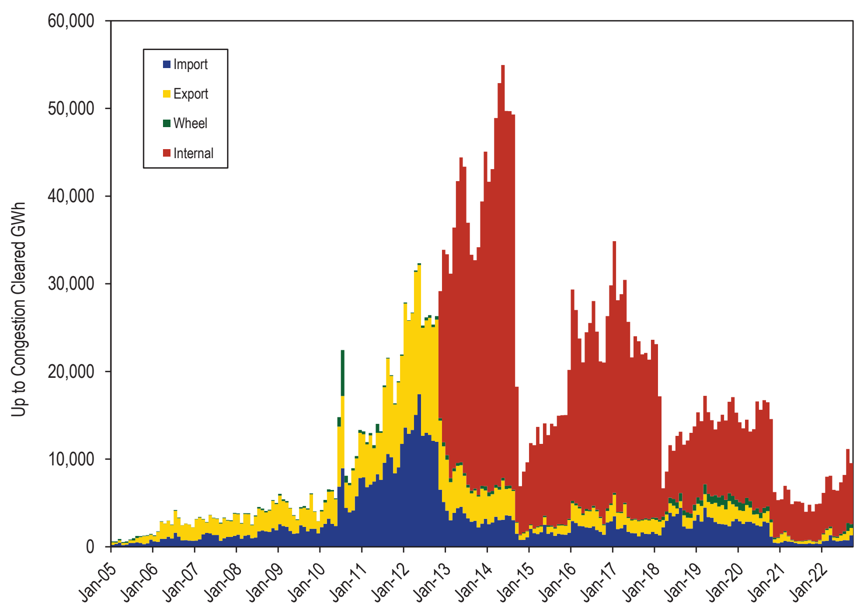
Figure 3-22 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through September 2022. An initial increase and continued increase in internal up to congestion transactions by month followed the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[60] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on

60 See 162 FERC ¶ 61,139 (2018).

February 22, 2018.[61] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[62] The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 52.8 percent, from 495,001 MWh per day in the 12 month period prior to the allocation of uplift charges (November 1, 2019, through October 31, 2020), to 233,632 MWh per day for the most recent 12 month period (October 1, 2021 through September 30, 2022). While the volume of UTCs has increased in recent months, the volume of UTCs remains well below the levels prior to the allocation of uplift charges.

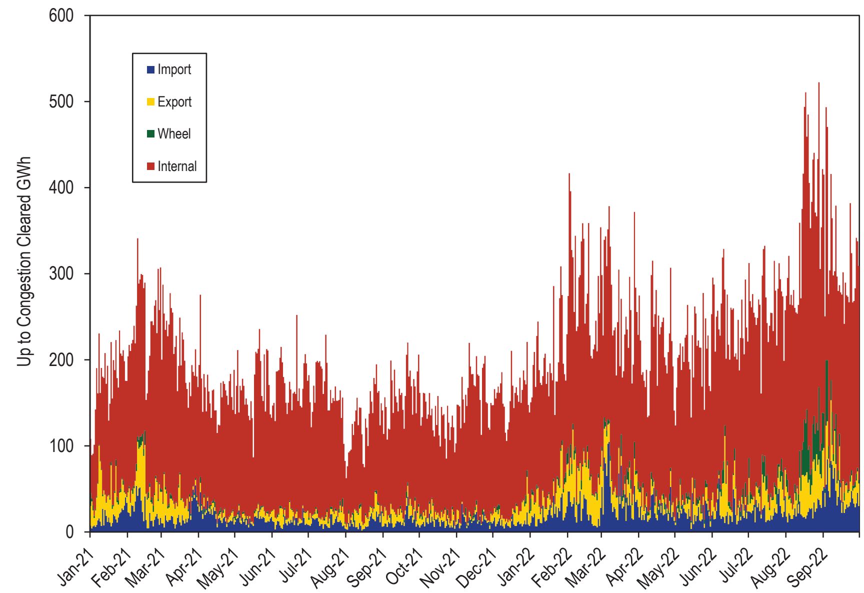
Figure 3-22 Monthly cleared up to congestion transactions by type (GWh): January 2005 through September 2022



61 *Id.*
62 See 172 FERC ¶ 61,046 (2020).

Figure 3-23 shows the daily cleared up to congestion GWh by transaction type from January 1, 2021, through September 30, 2022. In the first nine months of 2022, the total cleared GWh of import, export, and internal up to congestion transactions all increased compared to 2021.

Figure 3-23 Daily cleared up to congestion transaction by type (GWh): January 2021 through September 2022



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[63]

63 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them...Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[64] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For this reason, the MMU recommends eliminating UTC bidding at the following nodes: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in the real-time energy market. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day-ahead and real-time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be in the tens to hundreds of dollars, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day-ahead and real-time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

64 162 FERC ¶ 61,139 at PP 35–36 (2018) ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

Market Performance

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

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

The real-time average LMP in the first nine months of 2022 increased 116.7 percent from the first nine months of 2021, from $33.49 per MWh to $72.57 per MWh. 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 real-time load-weighted average LMP in the first nine months of 2022 was 34.6 percent higher than the real-time fuel-cost adjusted load-weighted average LMP in the first nine months of 2022. If fuel and emission costs in the first nine months of 2022 had been the same as in the first nine months of 2021, holding everything else constant, the load-weighted LMP would have been lower, $57.82 per MWh instead of the observed $77.84 per MWh. The costs of fuel, emissions, and consumables, the fundamental components of the real-time load weighted average LMP, increased $31.43 per MWh from $25.96 per MWh in the first nine months of 2021 to $57.39 per MWh in the first nine months of 2022, which accounts for 74.5 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP in the first nine months of 2022 increased 117.0 percent from the first nine months of 2021, from $33.34 per MWh to $72.36 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.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[65] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[66]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Fast Start Pricing

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021. Fast start pricing employs a new LMP calculation called the pricing run. The pricing run LMP (PLMP) is now the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously relaxing the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units meet the following conditions: notification time plus start time are less than or equal to one hour; minimum run time is less than or equal to one hour; and units are online and running for PJM, not self-scheduled. This pricing method is intended to allow inflexible resources to set prices with their commitment costs per MWh added to their marginal costs.

DLMP and PLMP

Table 3-31 shows the day-ahead and real-time monthly load-weighted average DLMP and PLMP since September 2021. The real-time load-weighted average PLMP was $77.84 per MWh for the first nine months of 2022, which is 6.3 percent, $4.61 per MWh, higher than the real-time load-weighted average DLMP of $73.23 per MWh. The day-ahead load-weighted average PLMP was $76.97 per MWh for the first nine months of 2022, which is 0.2 percent, $0.16 per MWh, higher than the day-ahead load-weighted average DLMP of $76.81 per MWh. The highest monthly differences occurred in July and August 2022 when the real-time load-weighted average PLMP exceeded the DLMP by $8.45 and $8.06 per MWh.

65 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

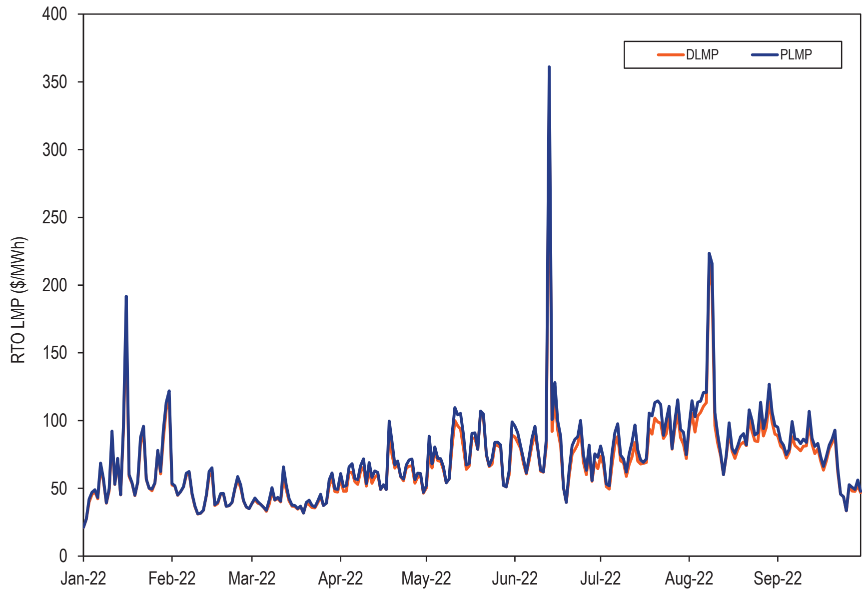
66 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

Table 3-31 Day-ahead and real-time load-weighted average DLMP and PLMP: September 2021 through September 2022

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2021	Sep	$46.00	$46.14	$0.13	0.3%	$47.73	$49.63	$1.90	4.0%
2021	Oct	$57.86	$57.98	$0.12	0.2%	$54.53	$58.42	$3.89	7.1%
2021	Nov	$60.76	$61.00	$0.24	0.4%	$59.27	$63.01	$3.74	6.3%
2021	Dec	$37.74	$37.85	$0.11	0.3%	$37.37	$38.92	$1.55	4.2%
2021	Sep - Dec	$50.30	$50.46	$0.15	0.3%	$49.47	$52.20	$2.73	5.5%
2022	Jan	$64.57	$64.80	$0.22	0.3%	$66.43	$69.06	$2.64	4.0%
2022	Feb	$49.96	$50.35	$0.39	0.8%	$45.93	$46.76	$0.83	1.8%
2022	Mar	$45.25	$45.50	$0.25	0.6%	$41.83	$43.56	$1.73	4.1%
2022	Apr	$64.10	$64.18	$0.08	0.1%	$60.38	$63.91	$3.52	5.8%
2022	May	$83.17	$83.24	$0.06	0.1%	$79.04	$83.16	$4.12	5.2%
2022	Jun	$90.24	$90.54	$0.29	0.3%	$91.44	$97.89	$6.46	7.1%
2022	Jul	$96.07	$96.38	$0.32	0.3%	$84.03	$92.48	$8.45	10.1%
2022	Aug	$106.18	$106.07	-$0.10	-0.1%	$105.68	$113.74	$8.06	7.6%
2022	Sep	$82.86	$82.80	-$0.06	-0.1%	$74.08	$78.29	$4.22	5.7%
2022	Jan - Sep	$76.81	$76.97	$0.16	0.2%	$73.23	$77.84	$4.61	6.3%

Figure 3-24 shows the real-time daily average DLMP and PLMP since September 2021.

Figure 3-24 Real-time daily average DLMP and PLMP: September 2021 through September 2022



Fast start pricing affected the difference between DLMP and PLMP in real time more than in day ahead. Figure 3-25 shows the hourly difference between DLMP and PLMP in day-ahead and real-time since September 2021. On August 24, 2022 14:00 (EPT), DLMP was $92.58 per MWh higher than PLMP in day ahead market. This resulted from a transmission constraint violation in the Dominion zone. In the day-ahead market, PJM uses a $30,000 per MWh transmission constraint penalty factor in the dispatch run, and a $2,000 per MWh transmission constraint penalty factor in the pricing run.

Figure 3-25 Hourly difference in DLMP and PLMP for day-ahead and real-time: September 2021 through September 2022

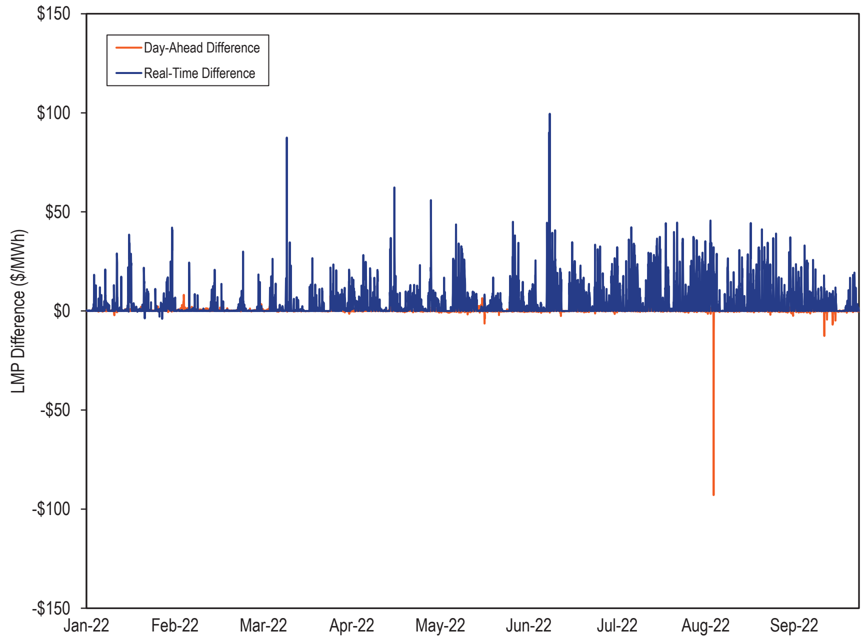


Figure 3-26 Hourly average load and LMP difference: January through September, 2022

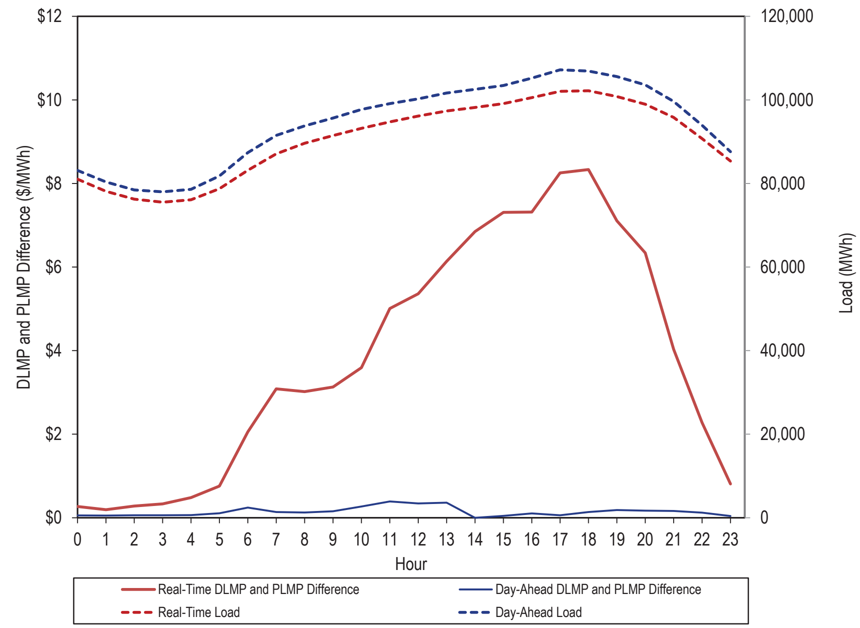


Figure 3-26 shows the hourly average load and LMP difference by hour of the day for the first nine months of 2022. The difference between real-time DLMP and PLMP is highest at 11:00 (EPT) and 18:00 (EPT).

Table 3-32 shows the percent of total marginal units that are fast start units by unit type since September 2021. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-32 Fast start units as a percent of marginal units: September 2021 through September 2022

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2021	Sep	1.3%	0.3%	0.2%	1.8%	5.0%	0.9%	0.2%	6.2%
2021	Oct	0.6%	0.2%	0.3%	1.2%	3.3%	0.5%	0.3%	4.0%
2021	Nov	0.5%	0.2%	0.4%	1.1%	3.5%	0.5%	0.4%	4.4%
2021	Dec	0.9%	0.1%	0.1%	1.2%	4.6%	0.3%	0.1%	5.0%
2022	Jan	1.3%	0.3%	0.2%	1.8%	5.0%	0.9%	0.2%	6.2%
2022	Feb	0.6%	0.2%	0.3%	1.2%	3.3%	0.5%	0.3%	4.0%
2022	Mar	0.5%	0.2%	0.4%	1.1%	3.5%	0.5%	0.4%	4.4%
2022	Apr	0.9%	0.1%	0.1%	1.2%	4.6%	0.3%	0.1%	5.0%
2022	May	1.5%	0.7%	0.1%	2.4%	6.8%	1.2%	0.1%	8.1%
2022	Jun	2.3%	0.3%	0.1%	2.6%	9.3%	0.8%	0.1%	10.2%
2022	Jul	2.2%	0.8%	0.1%	3.1%	15.5%	1.6%	0.0%	17.1%
2022	Aug	1.6%	0.4%	0.0%	2.1%	8.8%	1.3%	0.0%	10.1%
2022	Sep	0.8%	0.3%	0.1%	1.3%	5.8%	1.1%	0.1%	7.0%

Table 3-33 shows the difference in day-ahead and real-time zonal average DLMP and PLMP for the first nine months of 2022. Fast start pricing had different impacts by zone. As a result of fast start pricing, the average increase in real-time prices in BGE was 7.3 percent, $5.81 per MWh, while the average increase in real-time prices in PECO was 6.3 percent, $3.82 per MWh.

Table 3-33 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): January through September, 2022

	2022 (Jan-Sep)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$64.14	$64.30	$0.16	0.2%	$61.89	$65.80	$3.91	6.3%
AEP	$71.36	$71.56	$0.20	0.3%	$66.66	$71.38	$4.72	7.1%
APS	$72.33	$72.55	$0.22	0.3%	$67.54	$72.33	$4.79	7.1%
ATSI	$70.56	$70.78	$0.21	0.3%	$65.35	$69.99	$4.64	7.1%
BGE	$83.36	$83.55	$0.19	0.2%	$79.44	$85.25	$5.81	7.3%
COMED	$62.95	$63.12	$0.18	0.3%	$57.56	$61.95	$4.40	7.6%
DAY	$73.84	$74.04	$0.20	0.3%	$68.85	$73.70	$4.85	7.0%
DUKE	$72.57	$72.77	$0.20	0.3%	$67.28	$72.02	$4.74	7.1%
DOM	$84.84	$84.73	-$0.11	-0.1%	$84.17	$89.46	$5.29	6.3%
DPL	$68.11	$68.28	$0.17	0.2%	$66.49	$71.10	$4.60	6.9%
DUQ	$69.23	$69.44	$0.21	0.3%	$64.13	$68.72	$4.59	7.2%
EKPC	$71.68	$71.87	$0.19	0.3%	$67.16	$71.86	$4.70	7.0%
JCPLC	$65.37	$65.54	$0.17	0.3%	$63.12	$67.22	$4.10	6.5%
MEC	$75.10	$75.25	$0.15	0.2%	$70.81	$75.50	$4.69	6.6%
OVEC	$69.90	$70.09	$0.20	0.3%	$65.16	$69.75	$4.59	7.0%
PECO	$63.24	$63.40	$0.16	0.2%	$60.99	$64.81	$3.82	6.3%
PE	$70.06	$70.26	$0.20	0.3%	$65.05	$69.48	$4.43	6.8%
PEPCO	$80.39	$80.57	$0.18	0.2%	$76.38	$81.92	$5.53	7.2%
PPL	$69.08	$69.23	$0.16	0.2%	$65.26	$69.54	$4.29	6.6%
PSEG	$66.42	$66.58	$0.16	0.2%	$64.45	$68.50	$4.04	6.3%
REC	$68.85	$69.01	$0.16	0.2%	$66.39	$70.49	$4.10	6.2%

Table 3-34 shows the difference in day-ahead and real-time average DLMP and PLMP for PJM hubs for the first nine months of 2022.

Table 3-34 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): January through September, 2022

	2022 (Jan-Sep)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$69.31	$69.51	$0.20	0.3%	$64.37	$68.09	$3.72	5.8%
AEP-DAYTON HUB	$70.81	$71.01	$0.20	0.3%	$65.80	$69.62	$3.82	5.8%
ATSI GEN HUB	$69.29	$69.50	$0.21	0.3%	$63.93	$67.66	$3.73	5.8%
CHICAGO GEN HUB	$61.99	$62.17	$0.18	0.3%	$56.53	$60.06	$3.54	6.3%
CHICAGO HUB	$63.21	$63.39	$0.18	0.3%	$57.74	$61.34	$3.59	6.2%
DOMINION HUB	$77.60	$77.75	$0.15	0.2%	$74.03	$78.13	$4.10	5.5%
EASTERN HUB	$68.15	$68.33	$0.18	0.3%	$65.76	$69.71	$3.95	6.0%
N ILLINOIS HUB	$62.72	$62.90	$0.18	0.3%	$57.40	$60.95	$3.55	6.2%
NEW JERSEY HUB	$65.61	$65.78	$0.16	0.2%	$63.49	$66.82	$3.32	5.2%
OHIO HUB	$70.81	$71.01	$0.20	0.3%	$65.74	$69.56	$3.82	5.8%
WEST INT HUB	$72.05	$72.23	$0.17	0.2%	$67.35	$71.21	$3.86	5.7%
WESTERN HUB	$74.37	$74.56	$0.19	0.3%	$69.13	$73.14	$4.01	5.8%

Table 3-35 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for the first nine months of 2022.

Table 3-35 Real-time interval difference (dollars per MWh) in zonal DLMP and PLMP for January through September, 2022

	2022 (Jan-Sep)									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	0.0%	0.5%	50.8%	35.7%	7.5%	5.0%	0.4%	0.1%
ACEC	0.0%	0.0%	0.2%	6.0%	51.1%	32.3%	5.5%	4.2%	0.5%	0.1%
AEP	0.0%	0.0%	0.0%	0.7%	50.9%	35.3%	7.6%	5.0%	0.4%	0.1%
APS	0.0%	0.0%	0.0%	0.6%	50.9%	35.1%	7.6%	5.2%	0.4%	0.1%
ATSI	0.0%	0.0%	0.0%	0.8%	50.9%	35.6%	7.3%	4.9%	0.4%	0.1%
BGE	0.0%	0.0%	0.2%	2.6%	50.8%	31.5%	7.6%	6.2%	1.1%	0.1%
COMED	0.0%	0.0%	0.1%	1.8%	51.1%	35.0%	7.0%	4.5%	0.4%	0.1%
DAY	0.0%	0.0%	0.0%	0.7%	51.0%	35.0%	7.6%	5.2%	0.5%	0.1%
DUKE	0.0%	0.0%	0.0%	0.8%	51.0%	35.1%	7.6%	5.0%	0.4%	0.1%
DOM	0.0%	0.1%	0.3%	1.9%	50.9%	32.9%	7.3%	5.7%	0.8%	0.1%
DPL	0.0%	0.0%	0.2%	9.9%	51.0%	28.0%	5.2%	3.8%	1.4%	0.5%
DUQ	0.0%	0.0%	0.0%	0.9%	50.9%	35.7%	7.3%	4.7%	0.5%	0.1%
EKPC	0.0%	0.0%	0.0%	0.8%	51.0%	35.1%	7.7%	4.9%	0.4%	0.1%
JCPLC	0.0%	0.0%	0.1%	3.1%	51.1%	35.2%	5.7%	4.3%	0.5%	0.1%
MEC	0.0%	0.1%	0.3%	2.1%	50.8%	34.5%	6.7%	4.6%	0.7%	0.1%
OVEC	0.0%	0.0%	0.0%	0.9%	51.0%	35.3%	7.6%	4.7%	0.4%	0.1%
PECO	0.0%	0.0%	0.1%	8.8%	51.0%	29.8%	5.5%	4.2%	0.5%	0.1%
PE	0.0%	0.0%	0.1%	0.8%	50.7%	36.1%	7.3%	4.5%	0.4%	0.0%
PEPCO	0.0%	0.0%	0.1%	2.2%	50.9%	32.3%	7.6%	5.9%	0.9%	0.1%
PPL	0.0%	0.0%	0.2%	2.2%	50.8%	35.6%	6.4%	4.2%	0.5%	0.1%
PSEG	0.0%	0.0%	0.1%	2.7%	51.0%	35.4%	5.8%	4.4%	0.5%	0.1%
REC	0.0%	0.0%	0.1%	1.7%	50.9%	36.1%	6.1%	4.5%	0.5%	0.1%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[67]

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP for the first nine months of 1998 through 2022.[68] The real-time average LMP in the first nine months of 2022 increased 116.7 percent from the first nine months of 2021, from $33.49 per MWh to $72.57 per MWh. The price level is the highest real-time average LMP for the first nine months of a year, while the price increase of $39.08 per MWh and the percent price increase of 116.7 percent are the largest increases in average prices for the first nine months of a year since the creation of PJM markets in 1999.

Table 3-36 Real-time average LMP (Dollars per MWh): January through September, 1998 through 2022

	Real-Time LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA	NA
1999	$31.65	$18.77	$83.28	$8.47	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	($5.77)	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	$10.12	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	($7.88)	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	$12.30	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	$3.43	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	$10.83	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	($2.90)	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	$5.55	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	$14.59	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	($34.51)	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	$8.70	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	($0.33)	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	($13.34)	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	$4.85	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	$15.42	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	($16.76)	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	($8.53)	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	$1.36	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	$7.73	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	($10.22)	(28.0%)	(14.2%)	(46.8%)
2020	$19.95	$17.87	$10.48	($6.34)	(24.1%)	(23.6%)	(40.7%)
2021	$33.49	$26.82	$24.08	$13.54	67.9%	50.1%	129.8%
2022	$72.57	$59.66	$59.73	$39.08	116.7%	122.4%	148.0%

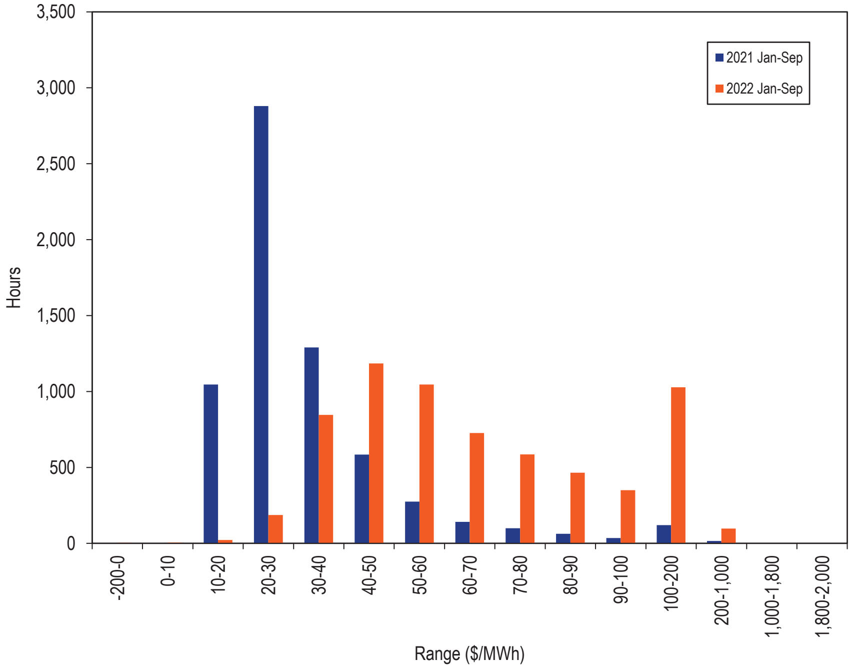
PJM Real-Time Average LMP Duration

Figure 3-27 shows the hourly distribution of the real-time average LMP for the first nine months of 2021 and 2022. There were 3,928 hours with an average LMP below $30 per MWh in the first nine months of 2021, but only 218 hours were in the same range in the first nine months of 2022. There were 120 hours with an average LMP between $100 to $200 per MWh in the first nine months of 2021, while 1,028 hours were in the same range in the first nine months of 2022.

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

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

Figure 3-27 Distribution of real-time LMP: January through September, 2021 and 2022



Real-Time Load-Weighted Average LMP

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

PJM Real-Time Load-Weighted Average LMP

Table 3-37 shows the real-time load-weighted average LMP for the first nine months of 1998 through 2022. 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 price level is the highest real-time load-weighted average LMP for the first nine months of a year, while the price increase of $42.16 per MWh and the percent price increase of 118.2 percent are the largest increases in load-weighted average prices for the first nine months of a year since the creation of PJM markets in 1999.

Table 3-37 Real-time load-weighted average LMP (Dollars per MWh): January through September, 1998 through 2022

	Real-Time Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA	NA
1999	$38.65	$20.02	$104.17	$12.59	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	($10.16)	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	$12.47	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	($9.01)	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	$11.61	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	$2.87	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	$14.01	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	($4.06)	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	$5.45	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	$15.43	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	($37.70)	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	$10.35	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	($0.44)	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	($14.46)	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	$4.72	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	$18.86	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	($19.66)	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	($9.62)	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	$1.04	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	$9.08	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	($11.83)	(30.0%)	(15.8%)	(49.2%)
2020	$21.22	$18.66	$11.53	($6.38)	(23.1%)	(23.0%)	(38.3%)
2021	$35.68	$28.41	$26.03	$14.46	68.1%	52.3%	125.8%
2022	$77.84	$63.39	$68.59	$42.16	118.2%	123.1%	163.5%

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-28 shows the real-time monthly and yearly load-weighted average LMP for January 1999 through September 2022.

Figure 3-28 Real-time monthly and yearly load-weighted average LMP: January 1999 through September 2022

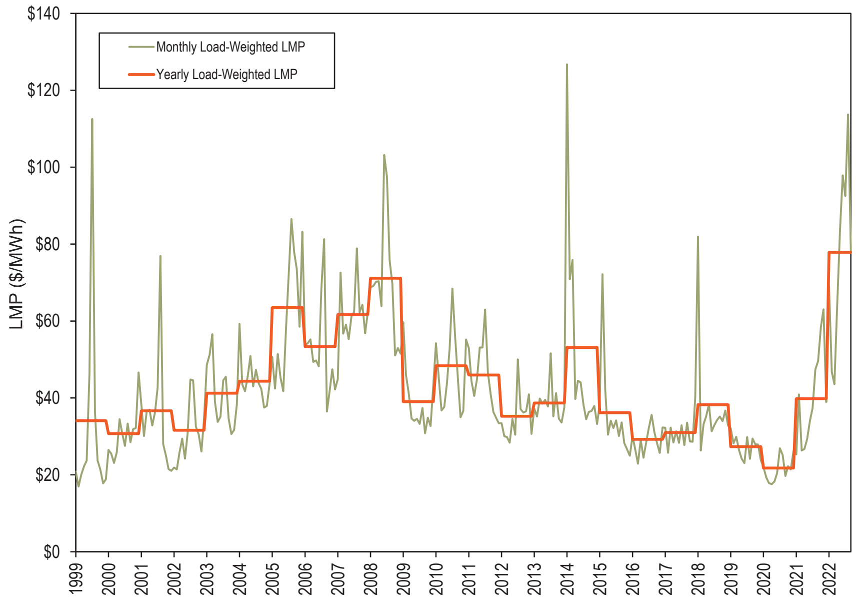


Table 3-38 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2021 through September 2022

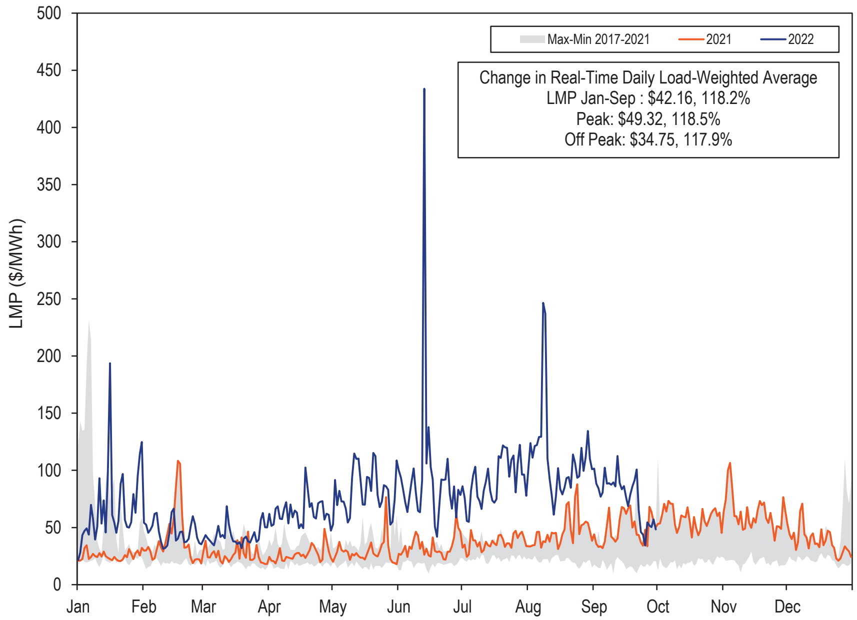
	2021				2022			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$23.53	$27.45	$3.91	16.6%	$74.99	$62.54	($12.46)	(16.6%)
Feb	$35.40	$46.40	$11.01	31.1%	$45.70	$47.86	$2.16	4.7%
Mar	$23.98	$28.43	$4.45	18.6%	$41.58	$45.41	$3.83	9.2%
Apr	$22.60	$30.45	$7.86	34.8%	$55.93	$71.89	$15.96	28.5%
May	$22.58	$36.80	$14.23	63.0%	$66.12	$100.85	$34.73	52.5%
Jun	$27.50	$39.88	$12.38	45.0%	$61.63	$126.83	$65.20	105.8%
Jul	$31.52	$42.83	$11.31	35.9%	$71.83	$114.14	$42.31	58.9%
Aug	$36.74	$56.71	$19.97	54.4%	$85.89	$136.31	$50.42	58.7%
Sep	$39.47	$59.03	$19.56	49.6%	$66.36	$89.76	$23.40	35.3%
Oct	$49.53	$67.34	$17.81	36.0%				
Nov	$55.73	$70.49	$14.76	26.5%				
Dec	$34.83	$42.56	$7.73	22.2%				

Table 3-38 shows the real-time monthly on peak and off peak load-weighted average LMP for 2021 through September 2022. The off peak value was higher than the on peak value in January 2022 mainly because of cold weather on weekends.

PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-29 shows the real-time daily load-weighted average LMP for 2021 through September 2022.

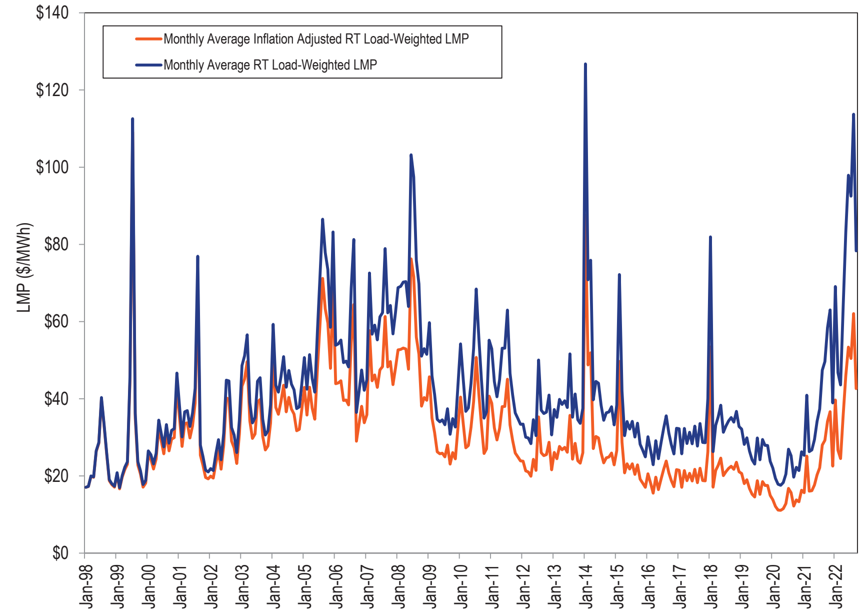
Figure 3-29 Real-time daily load-weighted average LMP: 2021 through September 2022



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

Figure 3-30 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through September 2022.[69] Table 3-39 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months of every year from 1998 through 2022. The nominal nine month PJM real-time load-weighted average LMP for 2022 was the highest since the PJM Real-Time Energy Market was implemented in 1998. The inflation adjusted nine month PJM real-time load-weighted average LMP for 2022 was the fifth highest.

Figure 3-30 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through September 2022



69 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 13, 2022)

Table 3-39 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through September, 1998 through 2022

	Load-Weighted Average LMP Jan-Sep	Inflation Adjusted Load-Weighted Average LMP Jan-Sep
1998	$26.06	$25.86
1999	$38.65	$37.55
2000	$28.49	$26.82
2001	$40.96	$37.39
2002	$31.95	$28.72
2003	$43.57	$38.33
2004	$46.44	$39.85
2005	$60.44	$50.09
2006	$56.39	$45.16
2007	$61.83	$48.36
2008	$77.27	$57.70
2009	$39.57	$29.93
2010	$49.91	$37.04
2011	$49.48	$35.59
2012	$35.02	$24.68
2013	$39.75	$27.58
2014	$58.60	$40.11
2015	$38.94	$26.60
2016	$29.32	$19.77
2017	$30.36	$20.05
2018	$39.43	$25.45
2019	$27.60	$17.49
2020	$21.22	$13.27
2021	$35.68	$21.39
2022	$77.84	$43.04

Real-Time Dispatch and Pricing

In the first ten months of 2021, real-time dispatch and pricing continued to not be temporally aligned. On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market is based on applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the real-time security constrained economic dispatch (RT SCED), the locational pricing calculator (LPC), and the ancillary services optimizer (ASO).[70] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

70 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 122 (Oct. 1, 2022)

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast at a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. In 2021 and the first nine months of 2022, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases were still for 10 minutes ahead while the LPC cases were for each five minute interval. As a result, under the default timing of case approvals, resources followed the dispatch signal in the first five minutes after the RT SCED case approval and the corresponding pricing occurred five minutes after the same case approval, when resources were following a new dispatch signal. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the concurrent dispatch signals.

Table 3-40 shows the number of RT SCED case solutions, the number of solutions that were approved and the number and percent of approved solutions used in LPC. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

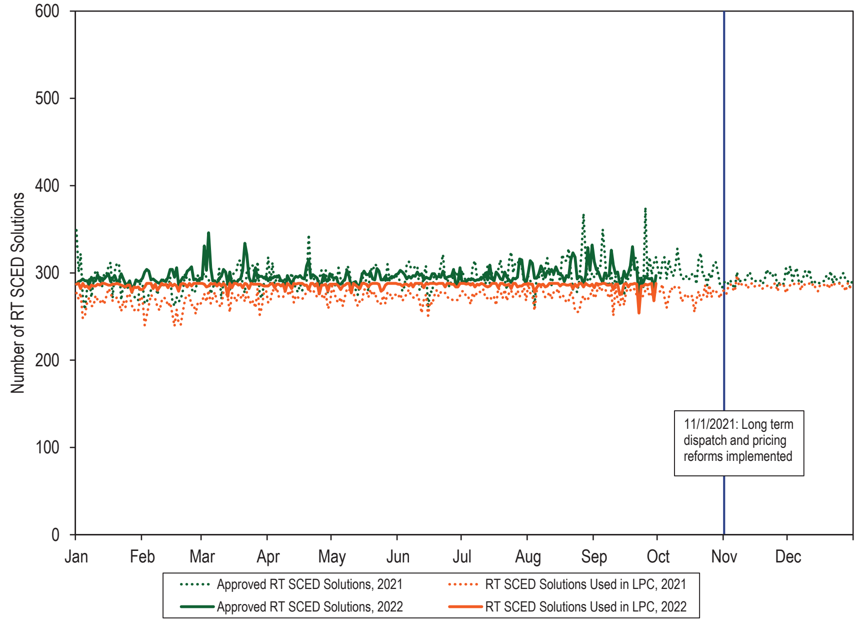
Table 3-40 shows that in the first nine months of 2022, 96.4 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 92.8 percent in 2021. The percent of approved solutions used for pricing increased in 2020 with the decrease in the frequency of executed RT SCED cases.

Figure 3-31 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources, and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in 2021 and the first nine months of 2022, and the date when PJM implemented the new real-time dispatch process that aligned the dispatch, pricing and settlement intervals. Figure 3-31 shows that the five minute dispatch reforms implemented on November 1, 2021 improved the percentage of dispatch signals reflected in prices.

Table 3-40 RT SCED cases solved, approved and used in pricing: 2021 through September 2022

	2021				2022			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	31,395	9,022	8,276	91.7%	46,494	9,035	8,846	97.9%
Feb	30,489	7,888	7,308	92.6%	41,456	8,281	8,001	96.6%
Mar	32,456	9,069	8,372	92.3%	45,704	9,296	8,863	95.3%
Apr	29,586	8,798	8,220	93.4%	44,155	8,832	8,566	97.0%
May	30,438	9,124	8,468	92.8%	45,385	9,118	8,862	97.2%
Jun	46,184	8,847	8,133	91.9%	43,995	8,900	8,605	96.7%
Jul	47,792	9,291	8,513	91.6%	45,453	9,151	8,879	97.0%
Aug	47,580	9,326	8,459	90.7%	45,161	9,395	8,869	94.4%
Sep	46,899	9,088	8,270	91.0%	43,623	8,956	8,523	95.2%
Oct	46,707	9,333	8,538	91.5%				
Nov	44,316	8,778	8,539	97.3%				
Dec	45,770	9,114	8,852	97.1%				
Total	479,612	107,678	99,948	92.8%	401,426	80,964	78,014	96.4%

Figure 3-31 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: 2021 and 2022



PJM's process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs had inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. Until November 1, 2021, PJM did not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, while settlements are linked to five minute intervals. In 2021, the frequency of automatic execution of RT SCED cases was one every five minutes. Until November 1, 2021, RT SCED solved the dispatch problem for a target time that was generally 14 minutes in the future. An RT SCED case was approved and sent dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target did not match, and a new RT SCED case overrode the previously approved case before resources had time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer applied at the time when resources received and followed that dispatch signal.[71] For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals at 9:55 EPT which were no longer effective from 10:00 to 10:05 EPT. In the first 10 months of 2021, there was a mismatch between the MW dispatch and real-time LMPs that undermined generators' incentive to follow dispatch. The timing remained incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all corresponded to one another, which PJM implemented on November 1, 2021.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when the corresponding prices applied. The start time for a dispatch instruction is the time at which PJM approves the RT SCED solution, which triggers sending the resulting dispatch instructions to resources. The end time for a dispatch instruction is the time when the next RT SCED solution is approved. Dispatch and pricing are perfectly aligned when the start and end times of the dispatch instructions from an approved RT SCED solution match with the start and end times of the LPC pricing interval that uses the same RT SCED solution. In a perfectly aligned five minute market, these times would both be five minutes in duration. In the first 10 months of 2021, RT SCED used a 10 minute ramp time to dispatch resources, while LPC applied prices to five minute intervals.

71 See Docket No. ER19-2573-000.

Beginning November 1, 2021, both RT SCED and LPC used the same five minute period to dispatch resources and calculate prices, which aligned the dispatch signals and prices in the real-time energy market.

Table 3-41 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in 2020, 2021 and the first nine months of 2022. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This was far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-41 shows that during the first 10 months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.0 percent. This is because by the time LMPs reflected the dispatch signals from an approved RT SCED solution, dispatchers had approved a new solution, and resources were instructed to follow new dispatch signals that did not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lagged dispatch instructions by five minutes, except in cases where dispatchers had not approved a new SCED solution five minutes after a previously approved solution. In the period beginning November 1, 2021, PJM aligned the dispatch and pricing intervals such that the prices that were effective for each five minute interval were generally based on the RT SCED case that sent dispatch signals with the target time at the end of the five minute interval. With these changes implemented on November 1, the dispatch instructions were consistent with the prices on average for 4 minutes and 46 seconds out of each five minute interval, or 95.4 percent of each five minute interval during November and December, 2021. In the first nine months of 2022, the dispatch instructions were consistent with the prices on average for 4 minutes and 45 seconds out of each five minute interval, or 95.7 percent of each five minute interval.

Table 3-41 Dispatch instructions reflected in prices: 2020 through September 2022

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%
Jan 1, 2021 - Oct 31, 2021	Every 5 minutes	00:33	9.0%
Nov 1, 2021 - Dec 31, 2021	Every 5 minutes	04:46	95.4%
Jan 1, 2022 - Sep 30, 2022	Every 5 minutes	04:45	95.7%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.[72] This only happens when RT SCED and LPC both use a five minute ramp time, consistent with the five minute real-time settlement period in PJM. The MMU recommended 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. PJM adopted the recommended changes on November 1, 2021. This resulted in prices used to settle energy for the five minute interval that ends at the RT SCED dispatch target time calculated consistent with the economic dispatch that targets the end of that five minute interval.[73]

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM

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

73 The implementation of fast start pricing on September 1, 2021, resulted in a much more significant misalignment between price and dispatch signals.

OATT allows for posting of recalculated real-time prices no later than 17:00 of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 17:00 of the second business day following the operating day.[74] Table 3-42 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2021 and 2022. In the first nine months of 2022, PJM recalculated LMPs for 2,806 five minute intervals or 3.57 percent of the total 78,612 five minute intervals.

Table 3-42 Number of five minute interval real-time prices recalculated: January 2021 through September 2022

	2021		2022	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated
January	8,928	12	8,928	179
February	8,064	496	8,064	663
March	8,916	49	8,916	361
April	8,640	266	8,640	345
May	8,928	29	8,928	188
June	8,640	22	8,640	170
July	8,928	190	8,928	218
August	8,928	58	8,928	339
September	8,640	31	8,640	343
October	8,928	22	-	-
November	8,652	162	-	-
December	8,928	165	-	-
Total	105,120	1,502	78,612	2,806

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[75]

PJM Day-Ahead Average LMP

Table 3-43 shows the day-ahead average LMP for the first nine months of 2001 through 2022. The day-ahead average LMP in the first nine months of 2022 increased 117.0 percent from the first nine months of 2021, from $33.34 per MWh to $72.36 per MWh.

Table 3-43 Day-ahead average LMP (Dollars per MWh): January through September, 2001 through 2022

	Day-Ahead LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA	NA
2002	$28.29	$22.54	$19.09	($7.78)	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	$12.91	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	$1.44	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	$11.85	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	($4.03)	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	$3.79	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	$17.19	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	($34.08)	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	$8.46	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	($0.67)	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	($12.98)	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	$5.34	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	$16.26	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	($17.09)	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	($8.76)	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	$0.99	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	$7.14	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	($9.63)	(26.7%)	(16.8%)	(61.9%)
2020	$19.72	$18.47	$6.99	($6.69)	(25.3%)	(25.4%)	(27.0%)
2021	$33.34	$28.28	$16.54	$13.63	69.1%	53.1%	136.7%
2022	$72.36	$63.56	$33.81	$39.02	117.0%	124.8%	104.4%

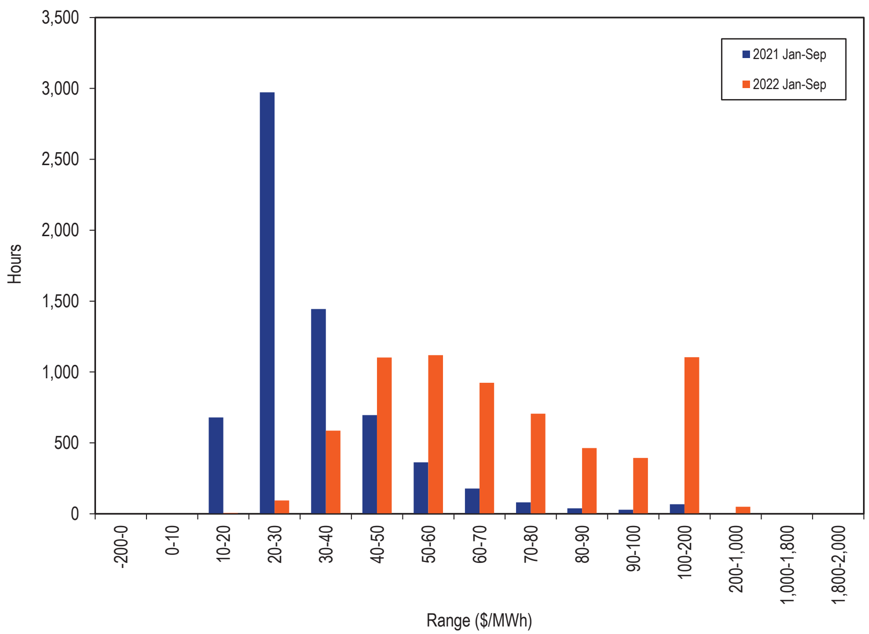
74 OA Schedule 1 § 1.10.8(e).

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

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of the day-ahead average LMP in the first nine months of 2021 and 2022.

Figure 3-32 Distribution of day-ahead LMP: January through September, 2021 and 2022



Day-Ahead Load-Weighted Average LMP

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

PJM Day-Ahead Load-Weighted Average LMP

Table 3-44 shows the day-ahead load-weighted average LMP in the first nine months of 2001 through 2022. 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.

Table 3-44 Day-ahead load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2022

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA	NA
2002	$32.29	$25.22	$22.81	($7.59)	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	$11.82	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	$0.49	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	$14.92	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	($5.32)	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	$3.59	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	$18.18	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	($36.61)	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	$9.77	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	($0.78)	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	($14.05)	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	$5.20	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	$19.60	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	($19.58)	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	($9.82)	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	$0.56	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	$8.45	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	($11.01)	(28.4%)	(18.3%)	(62.5%)
2020	$20.95	$19.23	$7.75	($6.75)	(24.4%)	(25.6%)	(25.4%)
2021	$35.51	$30.01	$17.97	$14.57	69.5%	56.0%	131.8%
2022	$76.97	$67.42	$36.82	$41.46	116.7%	124.7%	104.9%

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-33 shows the day-ahead monthly and yearly load-weighted average LMP from January 2001 through September 2022.

Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: January 2001 through September 2022

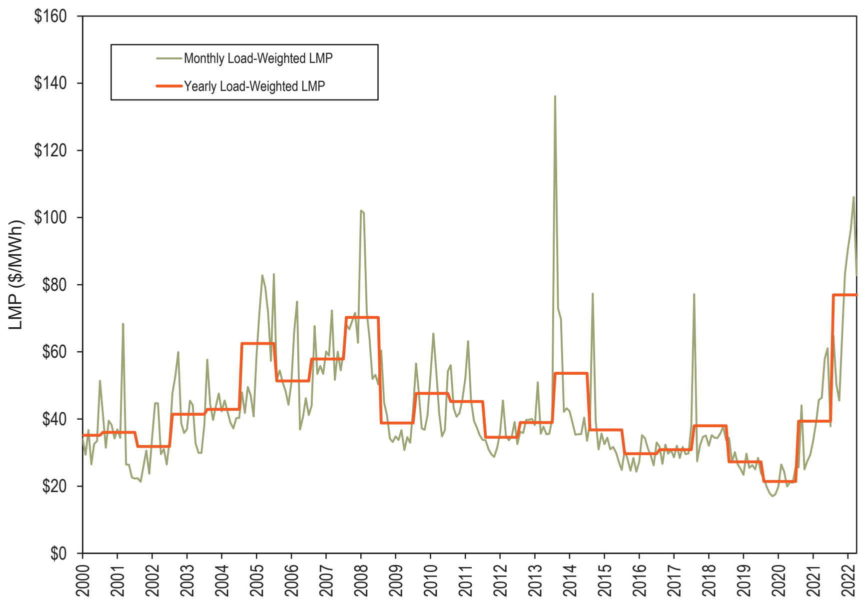
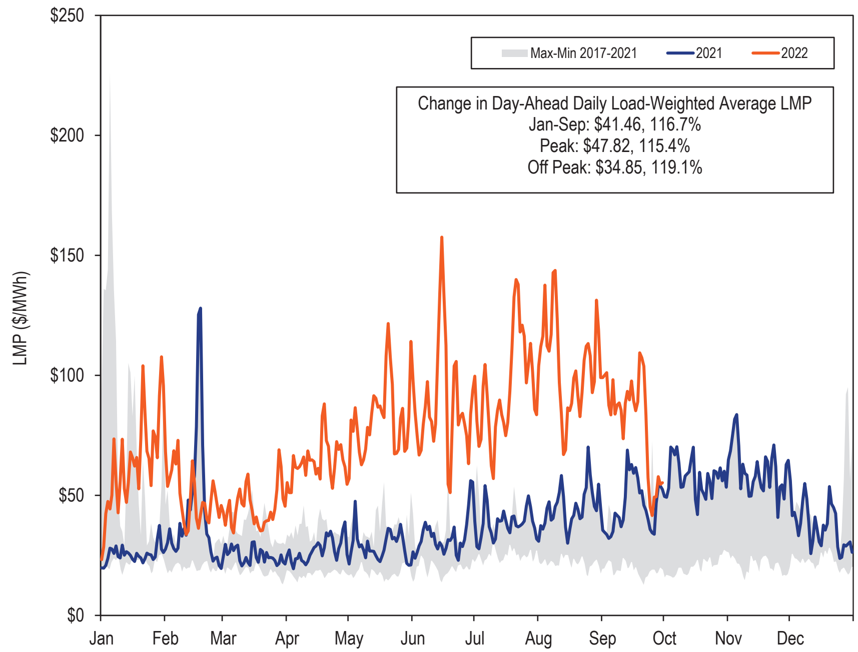


Figure 3-34 shows the day-ahead daily load-weighted average LMP for 2021 through September 2022 compared to the historic five year price range.

Figure 3-34 Day-ahead daily load-weighted average LMP: 2021 through September 2022



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

Figure 3-35 shows the PJM day-ahead, monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2022.[76] Table 3-45 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months of every year from 2000 through 2022.

76 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 13, 2022).

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through September 2022

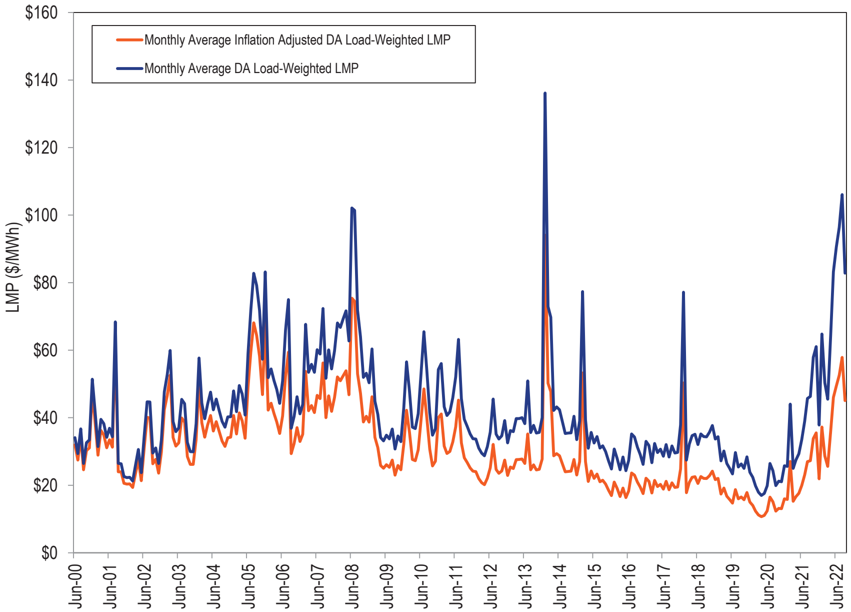


Table 3-45 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through September, 2000 through 2022

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	Jan-Sep
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99
2018	$38.71	$24.98
2019	$27.70	$17.55
2020	$20.95	$13.09
2021	$35.51	$21.30
2022	$76.97	$42.57

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

In practice, virtuals can receive a positive profit whenever there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets that is greater than uplift and administrative charges.

Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may result in positive profits for the virtual but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive profits, after uplift and administrative charges, when they contribute to price convergence, but with false arbitrage, profits result with little or no price convergence. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, after uplift and administrative charges, the INC is profitable. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, after uplift and administrative charges, the DEC is profitable.

The profit of a UTC transaction is the net of the separate revenues of the component INC and DEC, after uplift and administrative charges. A UTC can be profitable if the profits on one side of the UTC transaction exceed the losses on the other side.

Virtual transactions, including UTCs since November 1, 2020, are required to pay uplift charges. Cleared INCs and DECs pay deviation charges based on the daily RTO and applicable regional operating reserve charge rates. DECs pay day-ahead operating reserve charges in addition to deviation charges. Cleared UTCs are treated, for uplift purposes, like DECs at the UTC sink point, and pay the regional and RTO deviation rates in addition to the day-ahead rate. Uplift charges for deviations may not apply if the virtual transaction is partially or fully offset by a corresponding real-time physical transaction at the same location.

Profits of Virtual Transactions

The profit of a virtual transaction equals its net day ahead and real time energy market revenues minus uplift and administrative charges.

Table 3-46 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both points in the first nine months of 2021 and 2022. In the first nine months of 2022, 46.0 percent of all cleared UTC transactions were profitable. Of cleared UTC transactions, 66.7 percent were profitable on the source side and 34.3 percent were profitable on the sink side, but only 8.4 percent were profitable on both the source and sink side.

Table 3-46 Cleared UTC count with positive profits by source and sink point: January through September, 2021 and 2022[77]

(Jan-Sep)	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Share Profitable Source and Sink
2021	3,605,109	1,345,458	2,373,430	1,146,245	245,490	37.3%	65.8%	31.8%	6.8%
2022	3,826,397	1,759,491	2,553,823	1,310,898	319,815	46.0%	66.7%	34.3%	8.4%

77 Calculations exclude PJM administrative charges.

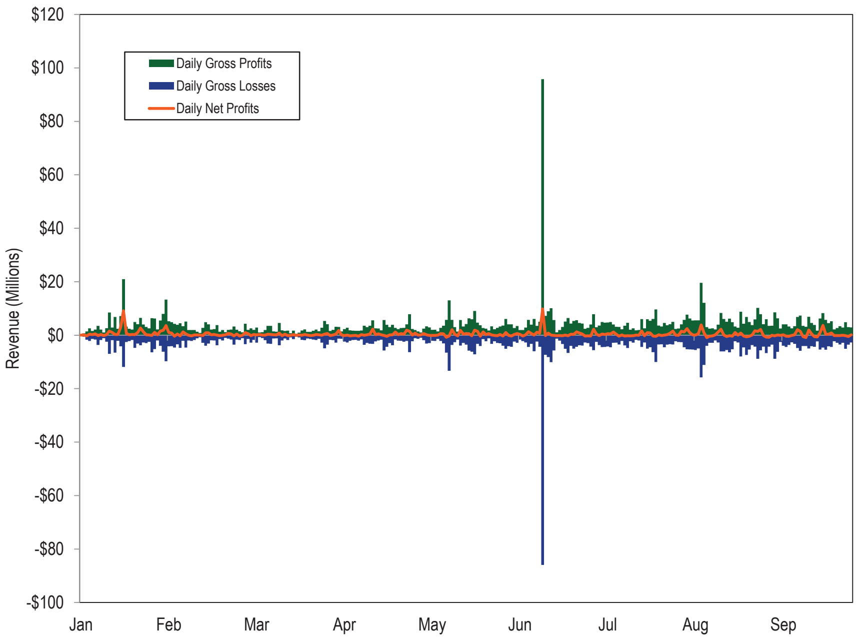
Table 3-47 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first nine months of 2021 and 2022. Of cleared INC and DEC transactions in the first nine months of 2022, 65.0 percent of INCs were profitable and 34.8 percent of DECs were profitable.

Table 3-47 Cleared INC and DEC count with positive profits: January through September, 2021 and 2022

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2021	1,597,788	1,027,414	64.3%	1,514,661	492,471	32.5%
2022	1,960,138	1,273,863	65.0%	1,726,190	601,008	34.8%

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in the first nine months of 2022.

Figure 3-36 Positive, negative, and net daily UTC profits: January through September 2022[78]



78 Calculations exclude PJM administrative charges.

Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through the first nine months of 2022.[79] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when these charges were first applied to UTCs. The top three lines show UTC profits in 2014, 2015, and 2013, with the truncated line showing profits in the first nine months of 2022. In the first nine months of 2022, total UTC profits reached the highest levels since 2015.

Figure 3-37 Cumulative daily UTC profits: January 2013 through September 2022

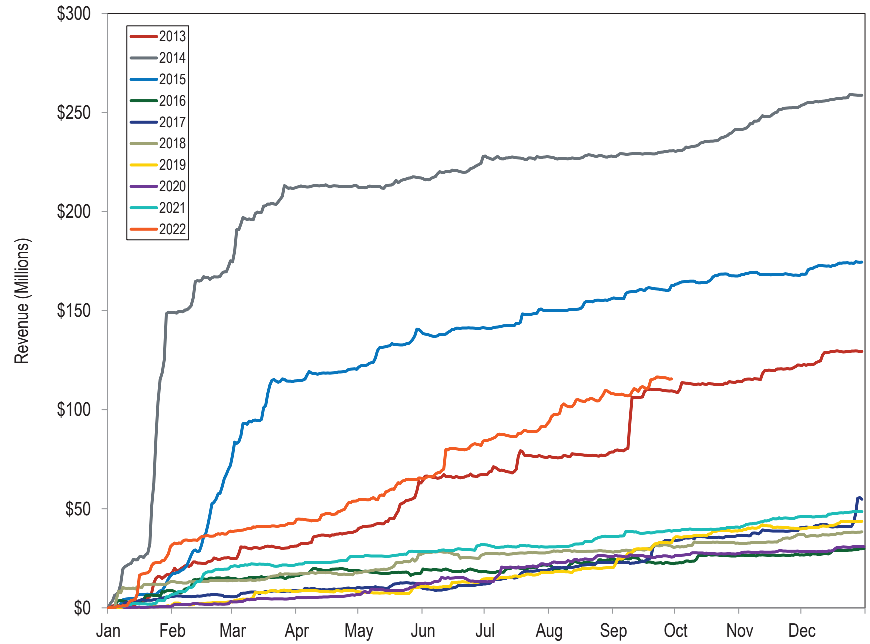


Table 3-48 shows UTC profits by month for January 2013 through September 2022. May 2016, September 2016, February 2017, June 2018, September 2020, and July 2021 were the only months in this seven year period in which monthly profits were negative. The totals include administrative charges for all months and uplift charges beginning in November 2020, when UTCs first

79 UTCs paid uplift only after October 31, 2020.

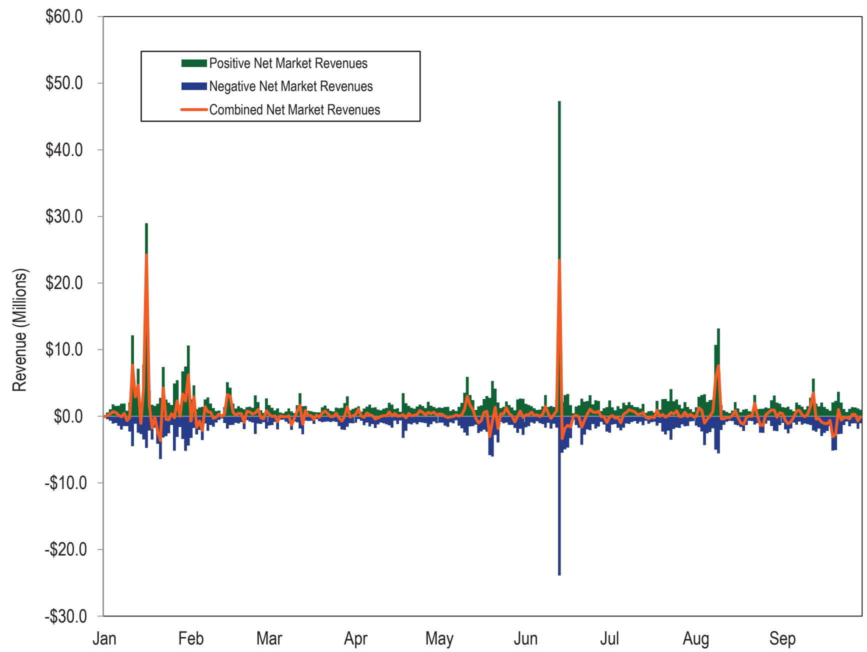
became subject to the charges. UTC profits in the first nine months of 2022 exceeded the total annual profits for all years since 2015.

Table 3-48 UTC profits by month: January 2013 through September 2022

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339
2022	$30,954,077	$7,236,325	$4,411,627	$11,317,095	$11,658,586	$16,398,181	$9,481,970	$17,376,381	$6,783,480				$115,617,722

Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in the first nine months of 2022. The most profitable days in the first nine months of 2022 were January 16 and June 12. In both cases, DECs benefited from high real-time prices resulting from violated internal transmission constraints. Differences in the modeling of transmission constraints between day ahead and real time, such as the use of different constraint limits or a constraint being modeled in one market but not the other, remain a principal source of false arbitrage profits and a major reason for the overall profitability of virtual transactions.

Figure 3-38 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through September, 2022[80]



80 Calculations exclude PJM administrative charges.

Figure 3-39 shows the positive, negative, and net daily profits for INCs in the first nine months of 2022.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: January through September, 2022[81]

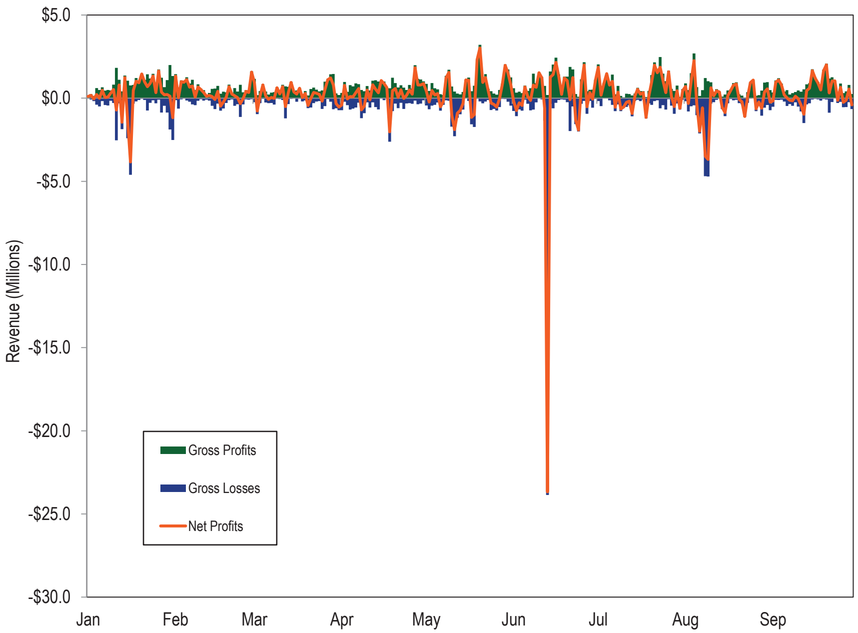


Figure 3-40 shows the positive, negative, and net daily profits for DECs in the first nine months of 2022.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: January through September, 2022[82]

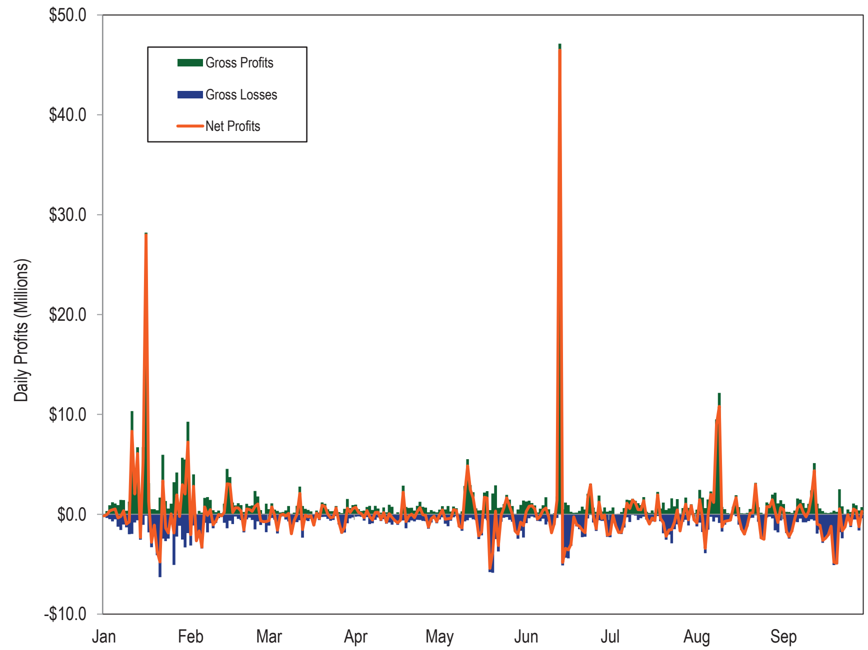


Figure 3-41 shows the cumulative INC and DEC daily profits in the first nine months of 2022. Both types of products had positive profits overall, though not consistently. Most of the profits for DECs in the first nine months of 2022 resulted from relatively brief but extreme fluctuations in real-time prices on a small number of days that were not in the day-ahead market. As a result, DECs were highly profitable on those days, most notably January 16 and June 13, and total DEC profits were positive in the first nine months of 2022 despite persistent losses outside of these days. Virtual trading can be profitable under these circumstances without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not correct for the use of different transmission constraint limits in day ahead versus real time.

81 Calculations exclude PJM administrative charges.

82 Calculations exclude PJM administrative charges.

Figure 3-41 Cumulative daily INC and DEC profit: January through September, 2022

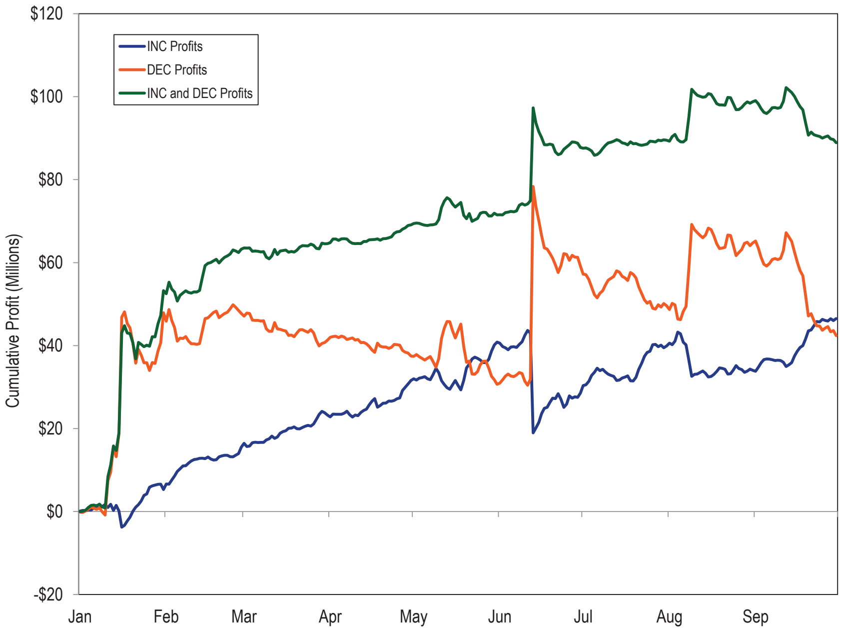


Table 3-49 shows INC and DEC profits by month in the first nine months of 2022.

Table 3-49 INC and DEC profits by month: January through September, 2022[83]

	January	February	March	April	May	June	July	August	September	Total
INCs	$5,990,481	$10,557,410	$8,072,680	$9,599,559	$10,172,184	($10,930,394)	$12,907,735	($4,085,860)	$13,435,429	$55,719,224
DECs	$49,590,589	$452,917	($5,964,605)	($2,442,963)	($5,340,438)	$30,759,108	($6,946,894)	$18,525,341	($20,202,457)	$58,430,598
INCs and DECs	$55,581,070	$11,010,326	$2,108,076	$7,156,596	$4,831,746	$19,828,714	$5,960,841	$14,439,481	($6,767,027)	$114,149,822

All virtual transactions are subject to uplift charges. Each cleared MWh of a virtual transaction pays uplift at the daily operating reserve charge rates. Cleared increment offers pay the regional and RTO deviation rates, and cleared decrement bids pay the day-ahead rate in addition. Cleared up to congestion transactions pay the same rate as a decrement bid at the transaction's sink point, the day-ahead rate and RTO and regional deviation rates.

In the first nine months of 2022, assuming that all virtual transactions are subject to the full deviation charges, INCs paid a total of $9.2 million in uplift, 16.5 percent of their gross revenues of $55.7 million. DECs paid a total of $16.0 million in uplift, 27.4 percent of their gross revenues of $58.4 million. UTCs paid a total of $32.8 million in uplift, 22.7 percent of their gross revenues of $144.4 million.[84]

Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct impact on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. Likewise, an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergences between day-ahead and real-time prices, which can be targeted by virtual traders. Because fast start pricing is more frequent in the real-time market, it means that, all else equal, real-time prices are higher than they otherwise would be, increasing the profitability of DECs and decreasing the profitability of INCs.

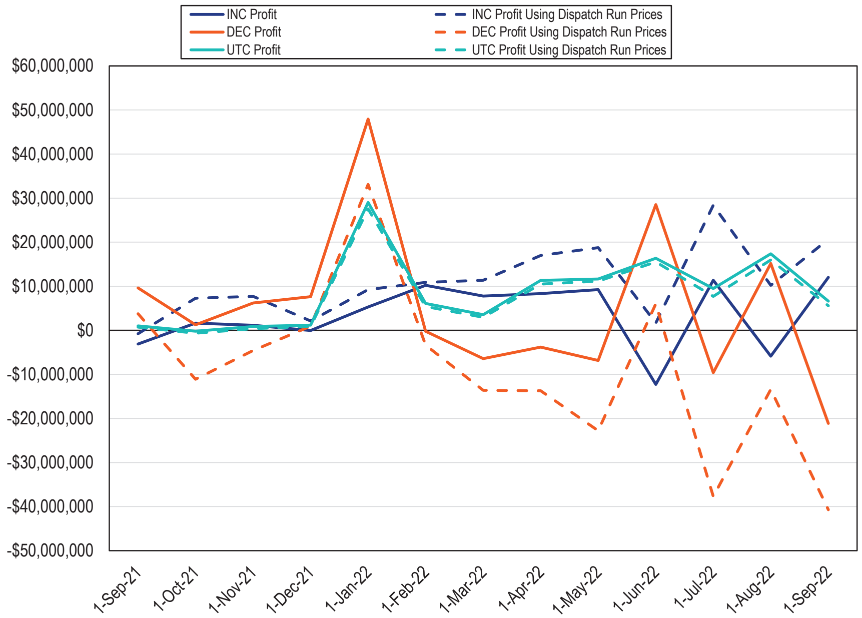
Figure 3-42 shows the total monthly profits received by INCs, DECs, and UTCs, compared to the profits they would have received if dispatch run prices had been used in settlement for each month since the initial implementation of fast start pricing in September 2021.

83 Versions of this table originally published in the 2021 Q2, Q3, and Annual State of the Market Reports had errors in the Total column which have been corrected.

84 Deviations incurred by virtual transactions may be partly or fully offset by physical injections or withdrawals in real time. But most virtual transactions pay the full uplift charge. In the first nine months of 2022, 98.7 percent of UTCs, 87.7 percent of DECs, and 90.9 percent of INCs paid the full deviation charge.

Since its implementation, fast start pricing has consistently increased profits for DECs and decreased profits for INCs but has not significantly affected profits for UTCs. Fast start pricing creates a difference between day-ahead and real-time prices. Virtual traders can benefit from this difference without contributing to price convergence.

Figure 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through September 30, 2022



From the implementation of fast start pricing on September 1, 2021, through September 30, 2022, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$98.9 million, the cumulative difference in profit for DECs was $185.5 million, and the cumulative difference in profit for UTCs was $10.5 million, or a net total of $97.3 million.

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, about modeling differences and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Day-ahead and Real-time Prices

Table 3-50 shows the difference between the day-ahead and the real-time average LMP.

Table 3-50 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2021 and 2022[85]

	2021				2022			
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$33.34	$33.49	$0.15	0.4%	$72.36	$72.57	$0.21	0.3%
Median	$28.28	$26.82	($1.46)	(5.4%)	$63.56	$59.66	($3.90)	(6.5%)
Standard deviation	$16.54	$24.08	$7.55	31.3%	$33.81	$59.73	$25.92	43.4%
Peak average	$39.48	$39.64	$0.16	0.4%	$84.96	$85.78	$0.81	0.9%
Peak median	$33.75	$31.77	($1.98)	(6.2%)	$77.24	$74.66	($2.58)	(3.5%)
Peak standard deviation	$19.35	$29.66	$10.32	34.8%	$38.28	$76.85	$38.57	50.2%
Off peak average	$27.98	$28.12	$0.14	0.5%	$61.23	$60.91	($0.32)	(0.5%)
Off peak median	$24.92	$24.43	($0.49)	(2.0%)	$55.97	$52.89	($3.08)	(5.8%)
Off peak standard deviation	$11.11	$16.00	$4.88	30.5%	$24.38	$34.83	$10.44	30.0%

Table 3-51 shows the difference between the day-ahead and the real-time load-weighted LMP for the first nine months of 2001 through 2022.

Table 3-51 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2022

	Load-Weighted Average LMP			
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$39.88	$40.96	$1.09	2.7%
2002	$32.29	$31.95	($0.33)	(1.0%)
2003	$44.11	$43.57	($0.54)	(1.2%)
2004	$44.59	$46.44	$1.84	4.0%
2005	$59.51	$60.44	$0.93	1.5%
2006	$54.19	$56.39	$2.19	3.9%
2007	$57.79	$61.83	$4.05	6.5%
2008	$75.96	$77.27	$1.30	1.7%
2009	$39.35	$39.57	$0.21	0.5%
2010	$49.12	$49.91	$0.79	1.6%
2011	$48.34	$49.48	$1.14	2.3%
2012	$34.29	$35.02	$0.73	2.1%
2013	$39.49	$39.75	$0.26	0.7%
2014	$59.09	$58.60	($0.49)	(0.8%)
2015	$39.51	$38.94	($0.57)	(1.5%)
2016	$29.69	$29.32	($0.37)	(1.3%)
2017	$30.26	$30.36	$0.10	0.3%
2018	$38.71	$39.43	$0.73	1.8%
2019	$27.70	$27.60	($0.10)	(0.4%)
2020	$20.95	$21.22	$0.28	1.3%
2021	$35.51	$35.68	$0.17	0.5%
2022	$76.97	$77.84	$0.87	1.1%

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

Table 3-52 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP for the first nine months of 2021 and 2022.

Table 3-52 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2021 and 2022

	2021 Jan - Sep		2022 Jan - Sep	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.0%	0	0.0%
($200) to ($100)	0	0.0%	3	0.0%
($100) to ($50)	12	0.2%	47	0.8%
($50) to $0	4,273	65.4%	4,278	66.1%
$0 to $50	2,177	98.6%	2,067	97.6%
$50 to $100	63	99.6%	95	99.1%
$100 to $200	17	99.9%	35	99.6%
$200 to $400	8	100.0%	17	99.9%
$400 to $800	1	100.0%	6	100.0%
>= $800	0	100.0%	3	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP for the first nine months of 2021. The highest value was $2,474.45 per MWh on June 13, 2022.

Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: January through September, 2022

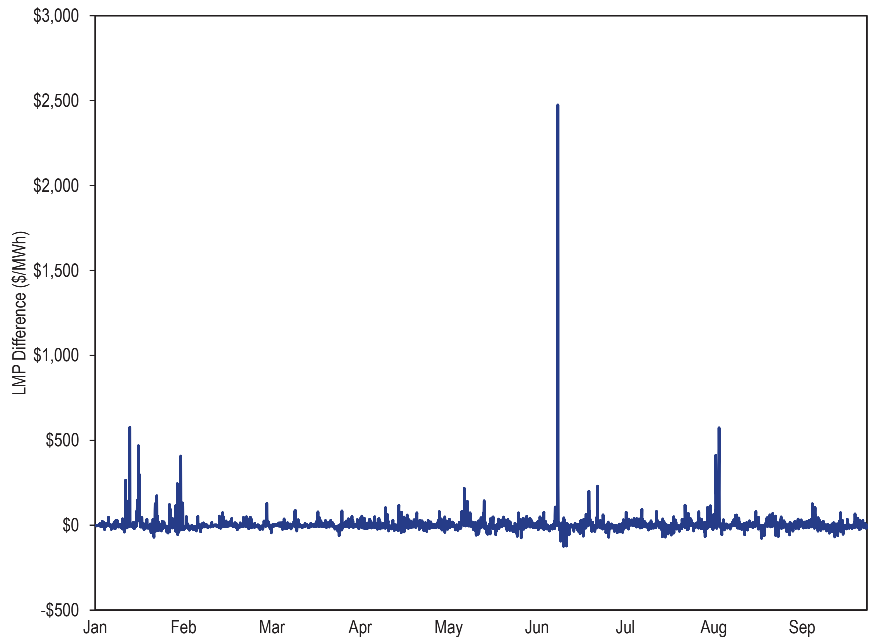
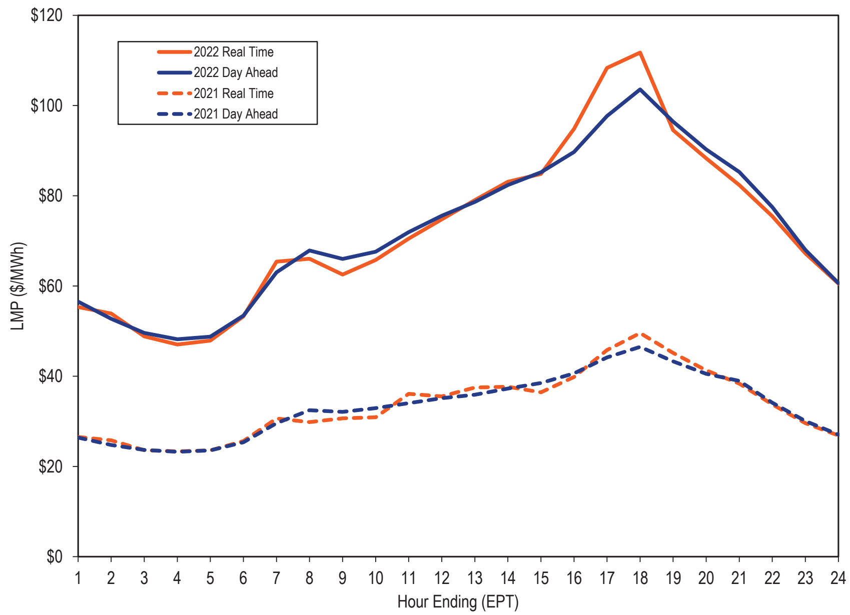


Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day for the first nine months of 2021 and 2022.

Figure 3-44 System hourly average LMP: January through September, 2021 and 2022



Zonal LMP and Dispatch

Table 3-53 shows real-time zonal average and load-weighted average LMP for the first nine months of 2021 and 2022.

Table 3-53 Real-time zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2021 and 2022

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
Zone	2021 Jan-Sep	2022 Jan-Sep	Percent Change	2021 Jan-Sep	2022 Jan-Sep	Percent Change
ACEC	$29.28	$65.07	122.2%	$32.26	$73.69	128.4%
AEP	$33.91	$70.53	108.0%	$35.70	$74.02	107.3%
APS	$33.43	$71.48	113.8%	$35.21	$75.07	113.2%
ATSI	$32.77	$69.16	111.0%	$34.76	$73.19	110.6%
BGE	$37.73	$84.18	123.1%	$40.68	$92.71	127.9%
COMED	$31.88	$61.13	91.7%	$34.49	$66.38	92.5%
DAY	$35.62	$72.82	104.5%	$38.09	$77.57	103.7%
DUKE	$34.52	$71.16	106.1%	$37.03	$76.28	106.0%
DOM	$37.07	$88.35	138.3%	$39.68	$96.46	143.1%
DPL	$34.55	$70.55	104.2%	$37.57	$80.70	114.8%
DUQ	$32.41	$67.90	109.5%	$34.57	$72.70	110.3%
EKPC	$33.75	$71.02	110.4%	$36.12	$74.84	107.2%
JCPLC	$29.16	$66.45	127.9%	$31.96	$75.30	135.6%
MEC	$32.46	$74.57	129.8%	$35.06	$81.14	131.4%
OVEC	$32.61	$68.93	111.4%	$32.71	$67.60	106.7%
PECO	$29.06	$64.11	120.6%	$31.29	$70.72	126.0%
PE	$31.36	$68.71	119.1%	$32.72	$71.43	118.3%
PEPCO	$36.30	$80.91	122.9%	$39.30	$88.97	126.4%
PPL	$30.11	$68.72	128.3%	$31.78	$73.25	130.5%
PSEG	$31.20	$67.84	117.4%	$33.53	$74.60	122.5%
REC	$33.64	$69.92	107.9%	$36.82	$78.57	113.4%
PJM	$33.49	$72.57	116.7%	$35.68	$77.84	118.2%

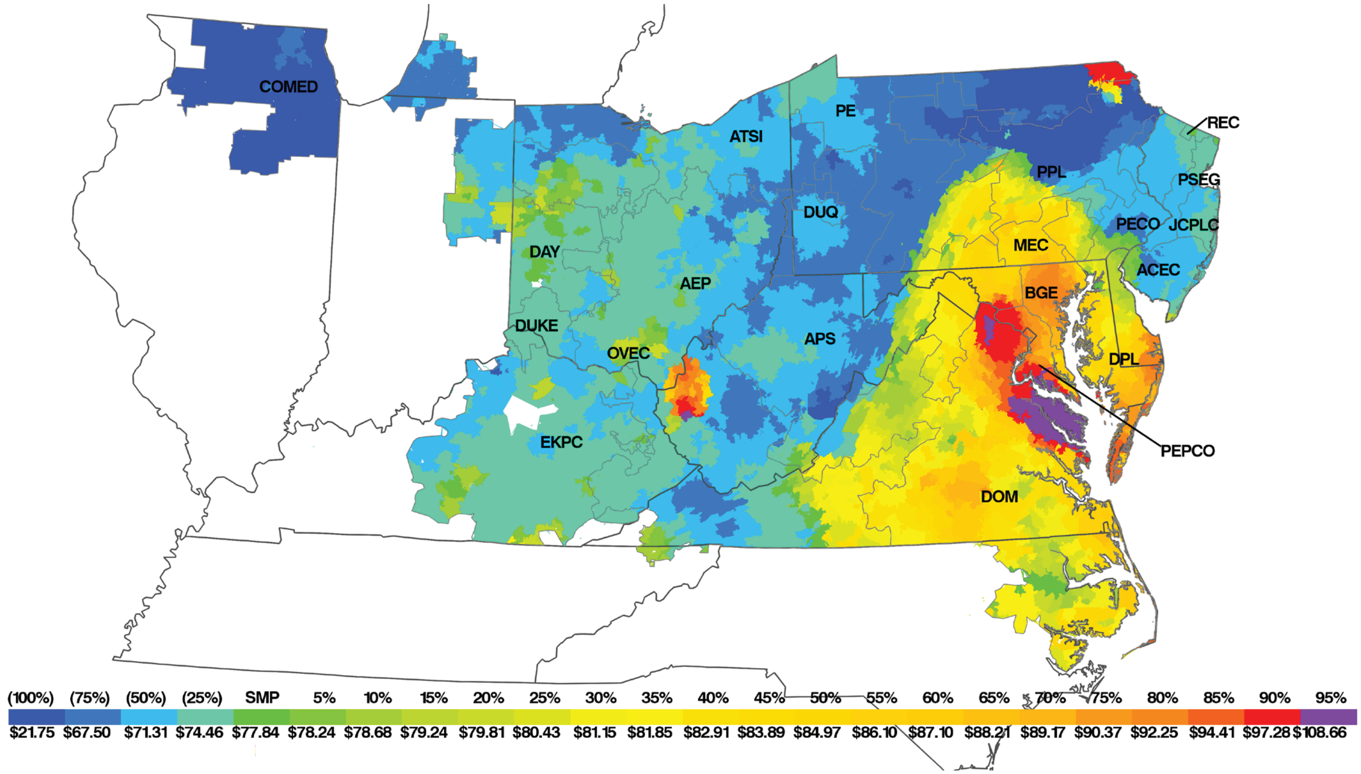
Table 3-54 shows day-ahead zonal average and load-weighted average LMP for the first nine months of 2021 and 2022.

Table 3-54 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2021 and 2022

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
Zone	2021 Jan-Sep	2022 Jan-Sep	Percent Change	2021 Jan-Sep	2022 Jan-Sep	Percent Change
ACEC	$29.49	$64.30	118.0%	$32.26	$70.80	119.5%
AEP	$33.74	$71.56	112.1%	$35.60	$75.19	111.2%
APS	$33.47	$72.55	116.8%	$35.21	$75.06	113.2%
ATSI	$33.30	$70.78	112.5%	$35.06	$74.49	112.5%
BGE	$37.59	$83.55	122.3%	$40.42	$90.51	123.9%
COMED	$31.77	$63.12	98.7%	$34.10	$68.04	99.5%
DAY	$35.74	$74.04	107.2%	$38.21	$78.54	105.5%
DUKE	$34.79	$72.77	109.1%	$37.21	$78.14	110.0%
DOM	$36.24	$84.73	133.8%	$38.92	$91.94	136.2%
DPL	$33.17	$68.28	105.9%	$36.53	$76.52	109.4%
DUQ	$32.80	$69.44	111.7%	$34.86	$73.73	111.5%
EKPC	$33.48	$71.87	114.6%	$36.06	$75.80	110.2%
JCPLC	$29.60	$65.54	121.4%	$32.15	$71.93	123.7%
MEC	$32.50	$75.25	131.6%	$34.94	$80.60	130.6%
OVEC	$32.71	$70.09	114.3%	$35.99	$72.69	102.0%
PECO	$29.14	$63.40	117.6%	$31.18	$68.60	120.0%
PE	$32.27	$70.26	117.7%	$34.15	$73.49	115.2%
PEPCO	$36.02	$80.57	123.7%	$38.88	$87.66	125.5%
PPL	$30.28	$69.23	128.6%	$31.86	$73.01	129.2%
PSEG	$30.42	$66.58	118.9%	$32.67	$71.47	118.8%
REC	$32.41	$69.01	112.9%	$36.05	$75.98	110.8%
PJM	$33.34	$72.36	117.0%	$35.51	$76.97	116.7%

Figure 3-45 is a map of the real-time load-weighted average LMP for the first nine months of 2022. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-45 Real-time load-weighted average LMP: January through September, 2022



Transmission Penalty Factors

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-55 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2022, there were 149,931 transmission constraint intervals in the real-time market with a nonzero shadow price. For about 12 percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[86] In the first nine months of 2022, the average shadow price of transmission constraints when the line limit was violated was 7.1 times higher than when the transmission constraint was binding at its limit. PJM activated the Greys Point-Harmony 115 kV contingency constraint in the Dominion Zone due to the outage of Lenexa-Dunnsville-Northern Neck 230 kV transmission line. The Greys Point-Harmony 115 kV contingency constraint accounted for nearly 14 percent of the violated transmission constraints in the first nine months of 2022.

Market to Market Transmission Constraints are categorized separately because of the unique rules governing the congestion management of these constraints by PJM and MISO. In the real time market, PJM and MISO initiate a joint congestion management process commonly referred as "market to market" if they recognize substantial flows originating from the other RTO on their constraints. The identified constraints are then modeled in the dispatch optimizations of the both RTOs. After every approved solution, the shadow prices are exchanged between the RTOs.

86 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

Table 3-55 Frequency and average shadow price of transmission constraints: January through September, 2021 and 2022

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2021 (Jan - Sep)	2022 (Jan - Sep)	2021 (Jan - Sep)	2022 (Jan - Sep)
Violated Transmission Constraints	9,338	17,472	$1,866.92	$1,807.84
Binding Transmission Constraints	72,667	74,715	$167.81	$254.44
Market to Market Transmission Constraints	30,776	57,744	$442.36	$471.54
All Transmission Constraints	112,781	149,931	$383.41	$519.08

Table 3-56 shows the frequency of violated transmission constraints by voltage level. In the first nine months of 2022, 94.5 percent of the violated transmission constraint intervals had a voltage level at or above 230 kV. Greys Point-Harmony 115 kV contingency constraint accounted for nearly 55 percent of the 115 kV violated transmission constraints in the first nine months of 2022. Of the 9,260 constraint violations at 230 kV, 63 percent were in the Dominion zone, with increased load from data centers and relatively higher natural gas prices compared to the rest of the PJM footprint.

Table 3-56 Frequency of PJM violated transmission constraints by voltage: January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
69 kV	961	10.3%	326	1.9%
115 kV	1,995	21.4%	4,435	25.4%
138 kV	2,727	29.2%	2,495	14.3%
161 kV	33	0.4%	-	0.0%
230 kV	2,884	30.9%	9,260	53.0%
345 kV	400	4.3%	278	1.6%
500 kV	304	3.3%	564	3.2%
765 kV	34	0.4%	114	0.7%
Total	9,338	100.0%	17,472	100.0%

Transmission penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[87] This could be the result of a lengthy planned transmission outage, for example.[88] It can also result from PJM reducing the line limit in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period.

PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020.

PJM routinely, based on discretion, reduces the line limit modeled in SCED to below 100 percent, generally to 95 percent of the actual limit. Table 3-57 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2022, there were 15,027 or 86 percent of 17,472 violated transmission constraint intervals in the real-time market with constraint limit less than 100 percent of the actual constraint limit. In the first nine months of 2022, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 5.5 percent.

87 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).
88 See *id.*

Table 3-57 Frequency of reduction in line ratings (constraint intervals): January through September, 2021 and 2022

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2021 (Jan - Sep)	2022 (Jan - Sep)	2021 (Jan - Sep)	2022 (Jan - Sep)	2021 (Jan - Sep)	2022 (Jan - Sep)
Violated Transmission Constraints	9,338	17,472	9,117	15,027	6.5%	5.5%
Binding Transmission Constraints	72,667	74,715	71,908	71,525	7.1%	6.4%
Market to Market Transmission Constraints	30,776	57,744	11,764	14,127	5.6%	5.8%
All Transmission Constraints	112,781	149,931	92,789	100,679	6.9%	6.2%

Table 3-58 shows the reasons provided by the PJM dispatchers for changing the line rating for violated transmission constraints. In the first nine months of 2022, of the 15,027 violated transmission constraints with reduced line ratings, 2,401 or 16 percent were reduced because the relief calculated by the SCED optimization was less than the dispatcher's desired relief for the transmission constraint. No reason was provided for 10,395 instances, or 69 percent of all the instances. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in SCED. This practice has significant market impacts.

Table 3-58 PJM's reasons for reduction in line ratings (constraint intervals): January through September, 2021 and 2022

	Constraint Intervals		Average Reduction (Percentage)	
Reason	2021 (Jan - Sep)	2022 (Jan - Sep)	2021 (Jan - Sep)	2022 (Jan - Sep)
No reason provided	5,895	10,395	4.5%	4.4%
Prepositioning of generation resources to support an operational requirement	96	204	13.4%	9.8%
Inadequate relief calculated by the SCED optimization	1,547	2,401	8.5%	7.7%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	405	507	8.5%	8.0%
Modeled constraint is a thermal surrogate	63	35	83.2%	45.0%
Power flow on the constraint is volatile due to various system conditions	1,111	1,485	8.9%	7.4%
Total	9,117	15,027	6.5%	5.5%

Table 3-59 shows the impact on LMP of PJM dispatchers reducing the line ratings of transmission constraints and causing artificial line limit violations. The transmission penalty factor contribution to the load weighted average LMP in the first nine months of 2022 was $4.18 per MWh. If 100 percent of the line limits had been used 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 would have decreased to -$0.16 per MWh or 103.9 percent lower. On June 13, 2022, PJM reduced the line limit of several transmission constraints including the Conastone-Peach Bottom 500 kV transmission constraint in the SCED dispatch software. The Conastone-Peach Bottom constraint was violated even though the state estimator flows on the constraint never exceeded the actual ambient temperature adjusted line rating. The constraint violation led to more than $700 per MWh penalty factor added to the system marginal price for energy during some intervals on June 13, 2022.

Table 3-59 Real-time LMP impact of reduced line limits for PJM transmission constraints (Dollars per MWh): January through September, 2021 and 2022

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2021 (Jan - Sep)	2022 (Jan - Sep)
Line Limits Reduced by PJM (Actual)	$3.08	$4.18
Hypothetical Use of Full Line Limits	$0.96	($0.16)
Change in Contribution to LMP	($2.11)	($4.34)
Percent Change in Contribution to LMP	(68.7%)	(103.9%)

Table 3-60 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first nine months of 2022, there were 15,223 or 87 percent of internal violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh. Of the 2,182 constraint intervals violated with a penalty factor reduced below the default of $2,000 per MWh, the Greys Point-Harmony 115 kV contingency constraint accounted for nearly 71 percent in the first nine months of 2022. On August 9, 2022, PJM increased the transmission penalty factor to $3,000 for West Transfer Interface constraint. For four five minute intervals, the transmission penalty factor set the shadow price of the West Transfer Interface constraint at $3,000 per MWh and for three five minute intervals, the shadow price of the West Transfer Interface constraint was between $2,000 and $3,000.

Table 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
Violated Transmission Constraints	8,190	190	958	15,223	67	2,182
Binding Transmission Constraints	71,367	26	1,274	74,003	32	680
Market to Market Transmission Constraints	4,623	-	26,153	7,356	31	50,357
All Transmission Constraints	84,180	216	28,385	96,582	130	53,219

Transmission constraint penalty factors frequently set prices when PJM models a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. In the first nine months of 2022, there were 410 five minute intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

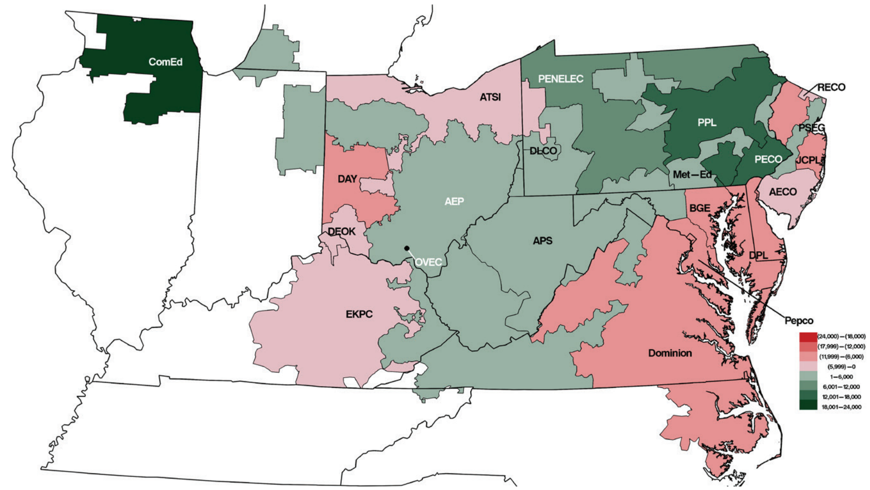
PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that is uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[89] Frequently, PJM dispatchers also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[90] PJM continues to use similar methods to artificially change the prices, like using thermal surrogates and forcing units to be marginal. These practices can lead to inefficient market outcomes.

Net Generation by Zone

Figure 3-46 shows the difference between the PJM real-time generation and real-time load by zone for the first nine months of 2022. Figure 3-46 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-61 shows the difference between the real-time generation and real-time load by zone for the first nine months of 2021 and 2022.

Figure 3-46 Map of real-time generation less real-time load by zone: January through September, 2022[91]



89 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.

90 167 FERC ¶ 61,058 at P 69 (2019).

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

Table 3-61 Real-time generation less real-time load by zone (GWh): January through September, 2021 and 2022

Zonal Generation and Load (GWh)						
Jan-Sep	2021			2022		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	2,252	7,684	(5,432)	2,487	7,744	(5,257)
AEP	109,476	94,442	15,034	109,538	95,084	14,454
APS	41,172	36,363	4,808	43,897	36,537	7,360
ATSI	37,476	49,042	(11,567)	43,434	49,669	(6,235)
BGE	13,858	23,435	(9,577)	13,210	23,352	(10,142)
COMED	99,058	71,320	27,738	101,028	71,032	29,996
DAY	809	12,829	(12,020)	1,086	12,947	(11,861)
DUKE	13,108	20,038	(6,930)	13,660	20,126	(6,467)
DOM	75,661	80,912	(5,250)	70,631	84,650	(14,019)
DPL	3,377	14,157	(10,780)	4,139	14,237	(10,098)
DUQ	12,523	9,963	2,561	13,040	10,021	3,020
EKPC	8,416	9,746	(1,330)	8,121	9,956	(1,835)
JCPLC	5,551	17,077	(11,526)	7,490	17,129	(9,639)
MEC	13,961	11,726	2,235	14,653	11,808	2,845
OVEC	8,419	86	8,333	8,594	84	8,510
PECO	54,942	29,604	25,338	54,553	29,726	24,827
PE	33,157	12,540	20,618	28,580	12,599	15,981
PEPCO	9,303	21,402	(12,099)	8,299	21,435	(13,137)
PPL	52,094	30,470	21,623	51,097	30,830	20,267
PSEG	32,924	32,482	442	33,960	32,886	1,074
RECO	0	1,098	(1,098)	0	1,106	(1,106)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, power to onsite customers, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during intervals when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during intervals when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-62 shows PJM generation by fuel source in GWh for the first nine months of 2021 and 2022. 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.

Table 3-62 Generation (By fuel source (GWh)): January through September, 2021 and 2022[92 93]

	2021 Jan - Sep		2022 Jan - Sep		Change in
	GWh	Percent	GWh	Percent	Output
Coal	152,586.7	24.0%	134,082.6	20.9%	(12.1%)
Bituminous	135,535.3	21.3%	116,561.2	18.2%	(14.0%)
Sub Bituminous	12,490.2	2.0%	12,574.8	2.0%	0.7%
Other Coal	4,561.1	0.7%	4,946.6	0.8%	8.5%
Nuclear	204,164.2	32.1%	204,420.6	31.8%	0.1%
Gas	235,271.3	37.0%	255,443.9	39.8%	8.6%
Natural Gas CC	216,176.9	34.0%	234,744.0	36.6%	8.6%
Natural Gas CT	14,719.6	2.3%	14,624.3	2.3%	(0.6%)
Natural Gas Other Units	3,057.3	0.5%	4,950.7	0.8%	61.9%
Other Gas	1,317.5	0.2%	1,124.9	0.2%	(14.6%)
Hydroelectric	13,069.5	2.1%	12,652.1	2.0%	(3.2%)
Pumped Storage	4,053.6	0.6%	4,933.1	0.8%	21.7%
Run of River	7,957.0	1.3%	6,096.6	0.9%	(23.4%)
Other Hydro	1,058.9	0.2%	1,622.4	0.3%	53.2%
Wind	19,265.6	3.0%	21,865.7	3.4%	13.5%
Waste	3,335.9	0.5%	3,039.9	0.5%	(8.9%)
Oil	1,775.1	0.3%	1,798.5	0.3%	1.3%
Heavy Oil	61.7	0.0%	58.7	0.0%	(4.8%)
Light Oil	462.7	0.1%	437.4	0.1%	(5.5%)
Diesel	24.6	0.0%	57.6	0.0%	134.7%
Other Oil	1,226.2	0.2%	1,244.8	0.2%	1.5%
Solar	5,913.4	0.9%	7,617.1	1.2%	28.8%
Battery	28.5	0.0%	17.4	0.0%	(38.9%)
Biofuel	927.6	0.1%	1,073.4	0.2%	15.7%
Total	636,337.8	100.0%	642,011.1	100.0%	0.9%

92 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.
93 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-63 Monthly generation (By fuel source (GWh)): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	22,228.7	16,327.3	12,398.3	11,936.9	12,088.1	13,716.5	17,023.8	17,496.1	10,866.8	134,082.6
Bituminous	19,342.3	14,273.9	11,048.4	10,195.6	10,484.3	11,751.9	14,478.5	15,292.1	9,694.2	116,561.2
Sub Bituminous	2,221.2	1,504.5	921.9	1,280.6	987.6	1,450.8	1,948.2	1,626.8	633.2	12,574.8
Other Coal	665.2	548.9	428.1	460.6	616.3	513.7	597.1	577.2	539.5	4,946.6
Nuclear	25,053.1	21,743.6	22,442.0	19,429.4	22,653.9	23,188.5	24,069.0	23,676.5	22,164.6	204,420.6
Gas	27,493.7	24,136.2	25,884.6	20,621.7	23,665.8	30,298.9	36,695.7	36,257.9	30,389.4	255,443.9
Natural Gas CC	24,756.0	23,282.6	25,157.0	19,324.2	21,897.6	27,382.7	32,328.0	32,364.7	28,251.3	234,744.0
Natural Gas CT	1,888.3	606.2	462.2	983.7	1,301.7	2,102.8	2,983.1	2,747.8	1,548.4	14,624.3
Natural Gas Other Units	723.7	130.8	131.5	190.5	334.2	691.8	1,256.3	1,019.4	472.5	4,950.7
Other Gas	125.8	116.6	133.9	123.4	132.4	121.6	128.3	126.0	117.2	1,124.9
Hydroelectric	1,264.8	1,315.6	1,670.1	1,403.0	1,580.1	1,461.8	1,353.0	1,418.8	1,184.9	12,652.1
Pumped Storage	422.5	395.5	426.7	369.0	540.3	680.7	735.4	763.5	599.5	4,933.1
Run of River	719.9	806.5	1,120.8	916.2	855.6	530.8	352.9	381.6	412.4	6,096.6
Other Hydro	122.3	113.7	122.6	117.8	184.2	250.3	264.8	273.7	173.0	1,622.4
Wind	3,072.6	3,256.3	3,386.6	3,298.2	2,676.7	1,803.4	1,474.0	1,242.9	1,655.0	21,865.7
Waste	337.6	288.5	313.8	331.2	363.8	342.5	377.7	366.3	318.6	3,039.9
Oil	313.5	191.7	184.7	166.7	103.6	174.0	237.5	269.9	157.0	1,798.5
Heavy Oil	2.8	4.7	0.0	0.0	16.2	5.1	22.4	7.5	0.0	58.7
Light Oil	120.4	33.0	20.4	14.2	16.3	34.3	84.6	108.3	5.9	437.4
Diesel	26.1	7.0	2.8	0.3	0.3	3.9	4.4	12.8	0.0	57.6
Other Oil	164.2	147.0	161.6	152.2	70.9	130.7	126.0	141.3	151.0	1,244.8
Solar	427.0	565.0	754.2	956.1	945.1	1,103.4	998.7	989.8	877.8	7,617.1
Battery	2.2	1.5	2.1	1.8	2.0	2.0	2.0	1.8	2.1	17.4
Biofuel	131.3	120.6	107.9	97.2	114.9	131.0	127.6	139.9	102.9	1,073.4
Total	80,324.4	67,946.4	67,144.4	58,242.3	64,194.0	72,221.9	82,358.9	81,859.8	67,719.1	642,011.1

Table 3-64 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-64 Day-ahead and real-time average generation (By fuel source (GWh)): January through September, 2022

	2022 (Jan-Sep)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	Difference	Difference
Coal	136,108.8	21.3%	134,082.6	20.9%	(2,026.2)	(1.5%)
Bituminous	118,675.1	18.6%	116,561.2	18.2%	(2,113.9)	(1.8%)
Sub Bituminous	12,645.0	2.0%	12,574.8	2.0%	(70.2)	(0.6%)
Other Coal	4,788.7	0.8%	4,946.6	0.8%	157.9	3.3%
Nuclear	205,057.2	32.1%	204,420.6	31.8%	(636.7)	(0.3%)
Gas	255,275.7	40.0%	255,443.9	39.8%	168.2	0.1%
Natural Gas CC	237,168.2	37.2%	234,744.0	36.6%	(2,424.2)	(1.0%)
Natural Gas CT	11,710.4	1.8%	14,624.3	2.3%	2,913.9	24.9%
Natural Gas Other Units	5,219.8	0.8%	4,950.7	0.8%	(269.1)	(5.2%)
Other Gas	1,177.3	0.2%	1,124.9	0.2%	(52.4)	(4.4%)
Hydroelectric	12,947.5	2.0%	12,652.1	2.0%	(295.4)	(2.3%)
Pumped Storage	6,722.8	1.1%	4,933.1	0.8%	(1,789.7)	(26.6%)
Run of River	6,224.7	1.0%	6,096.6	0.9%	(128.1)	(2.1%)
Other Hydro	0.0	0.0%	1,622.4	0.3%	1,622.4	NA
Wind	17,861.4	2.8%	21,865.7	3.4%	4,004.3	22.4%
Waste	2,868.7	0.4%	3,039.9	0.5%	171.1	6.0%
Oil	1,509.0	0.2%	1,798.5	0.3%	289.5	19.2%
Heavy Oil	32.4	0.0%	58.7	0.0%	26.3	81.4%
Light Oil	225.5	0.0%	437.4	0.1%	211.9	93.9%
Diesel	35.8	0.0%	57.6	0.0%	21.9	61.1%
Other Oil	1,215.4	0.2%	1,244.8	0.2%	29.4	2.4%
Solar	5,490.7	0.9%	7,617.1	1.2%	2,126.4	38.7%
Battery	0.0	0.0%	17.4	0.0%	17.4	NA
Biofuel	1,217.2	0.2%	1,073.4	0.2%	(143.8)	(11.8%)
Total	638,336.3	100.0%	642,011.1	100.0%	3,674.8	0.6%

Table 3-65 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Table 3-65 Share of generation by fuel source: January through September, 2008 through 2022

Jan - Sep	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	7.7%	55.0%	34.3%	3.0%
2009	10.7%	50.0%	35.8%	3.6%
2010	11.4%	50.0%	34.3%	4.3%
2011	13.8%	48.2%	33.8%	4.2%
2012	19.7%	41.7%	34.1%	4.5%
2013	16.9%	44.3%	34.5%	4.3%
2014	17.6%	44.2%	33.7%	4.4%
2015	22.6%	38.1%	34.3%	5.0%
2016	27.1%	33.8%	33.9%	5.1%
2017	26.8%	32.2%	35.3%	5.7%
2018	30.7%	29.2%	33.8%	6.4%
2019	36.0%	24.5%	33.2%	6.3%
2020	40.6%	19.0%	33.7%	6.7%
2021	36.8%	24.0%	32.1%	7.2%
2022	39.6%	20.9%	31.8%	7.7%

Fuel Diversity

Figure 3-47 shows the fuel diversity index (FDI_e) for PJM energy generation.[94] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-62 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 31.6 percent from 2012 through September 30, 2022. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market

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

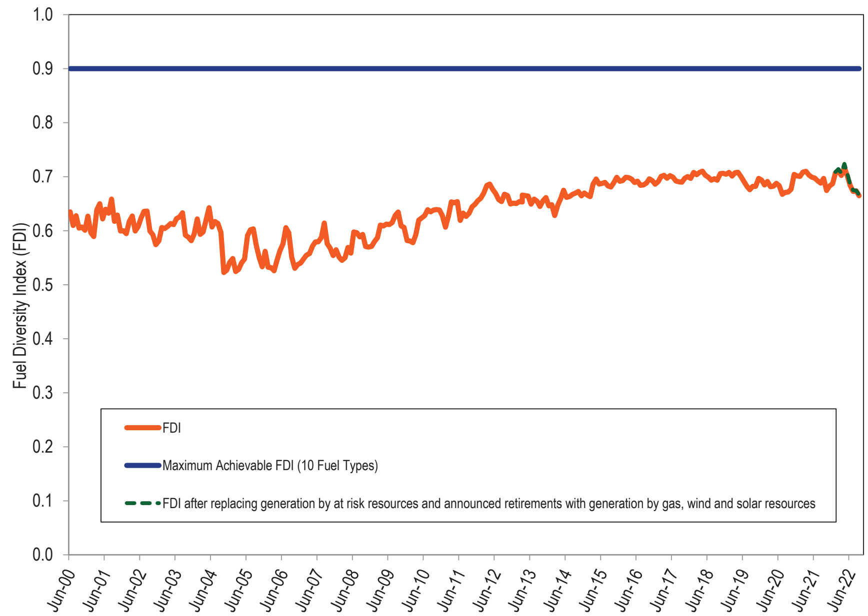
footprint into ComEd, AEP, and Dayton Power & Light Control Zones and the increased shares of coal and nuclear that resulted.[95] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 55.0 percent for the first nine months of 2008 and 20.9 percent for the first nine months of 2022. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 39.8 percent for the first nine months of 2022. Wind and solar generation as a share of total generation was 0.4 percent for the first nine months of 2008 and 4.6 percent for the first nine months of 2022.

The FDI_e decreased 0.9 percent for the first nine months of 2022 compared to the first nine months of 2021.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements. A total of 3,447 MW of capacity were identified as being at risk of retirement. Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[96] There are 5,770.3 MW of generation that have requested retirement after September 30, 2022.[97] The at risk units and other generators with deactivation notices generated 13,253.0 GWh during the first nine months of 2022. The dashed line in Figure 3-47 shows a counterfactual result for FDI_e assuming the 13,253.0 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas, wind and solar generation.[98] The FDI_e for the first nine months of 2022 under the counterfactual assumption would have been 0.4 percent higher than the actual FDI_e.

95 See the *2019 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Control Zones occurred in October 2004.
96 See PJM. OATT: § V "Generation Deactivation."
97 See Table 12-11 in the *2022 Quarterly State of the Market Report for PJM: January through June*, Section 12: Generation and Transmission Planning.
98 It is assumed that 8,632.4 GWh of the replacement energy is from new wind and solar units. This value represents the increase over third quarter 2022 levels in renewable generation that is required by RPS in 2023. The split between solar and wind, 6,459.4 GWh solar and 2,173.0 GWh wind, is based on queue data.

Figure 3-47 Fuel diversity index for monthly generation: June 2000 through September 2022



Natural Gas Supply Issues

Both pipeline transportation and commodity natural gas are needed to deliver natural gas to power plants. Generators have a number of options which vary by pipeline and market area. A generator could purchase a delivered service in which the seller bundles the transportation and commodity, purchased on a term contract or a spot basis. A generator could purchase pipeline transportation and purchase commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Generators could purchase storage service. Storage services can be bundled with pipeline transportation, or storage and transportation purchased separately to move gas to or from a storage facility. The storage contracted service will determine the total storage capacity and the injection and withdrawal rights. Storage offers the owner the ability to have on demand supplies, or the ability to redirect unused supplies to storage. Predetermined allocation (PDA) nominations can be used to direct the pipeline as to how to treat an excess or a deficiency of gas at a delivery point. Combinations of these options are also available.

The natural gas transportation gas day starts at 10:00 EPT each day and runs for 24 hours. Pipeline contracts for firm transportation designate the location of the firm entitlements for receipt and for deliveries. Firm service is guaranteed as long as the nomination cycles are followed, except during force majeure events. The transportation contract or tariff may also provide for locations on a secondary firm basis. In order to have the highest priority level of service, the receipt and delivery of gas must be at the receipt and delivery points designated in the contract.

In order to be able to actually use the purchased pipeline transportation service, generation owners must nominate the flow of gas by defined deadlines. Some pipelines also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-66 shows the approved nomination deadlines and corresponding start time of gas flow.[99] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-66 Approved nomination deadlines

	Nomination Cycle	Nom Deadline (EPT)	Time of Flow (EPT)	Bumping	Hours left in gas day for supply to flow
Day Before Flow	Timely	14:00	10:00		24
Day Before Flow	Evening	19:00	10:00	Yes	24
Day of Flow	Intraday 1	11:00	15:00	Yes	19
Day of Flow	Intraday 2	15:30	19:00	Yes	15
Day of Flow	Intraday 3	20:00	23:00	No	11

In 2021 and 2022, some interstate gas pipelines that provide service in the PJM service territory issued notices limiting the flexibility of firm and nonfirm transportation services. These notices include alerts, constraints, warnings of operational flow orders (OFO) and actual OFOs. These notices generally permit the pipelines to restrict the provision of gas to 24 hour ratable takes, meaning that nominations must be the same for each hour in the gas day. Pipelines may also enforce strict balancing constraints which limit the ability of gas users to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas. The following pipelines providing service in the PJM service territory issued notices: ANR Pipeline, Columbia Gas Transmission, Cove Point, Eastern Gas Transmission & Storage, Eastern Shore, Horizon Pipeline, Natural Gas Pipeline, Panhandle Eastern, Texas Eastern, Tennessee Gas Pipeline and Transcontinental Gas Pipeline.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlights the shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of total supply and demand across a broad geographical area that includes multiple pipelines. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrate the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

The increase in natural gas fired capacity in PJM, and the expected further increase, has highlighted issues with the dependence of PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, create risks for the bulk power system.

In general, the availability status of gas generators in the PJM energy market does not accurately reflect their ability to procure and nominate gas on the pipelines based on the rules defined by the pipelines. If the result of the pipeline rules is that some gas generators cannot reliably procure gas during the operating day in order to respond to PJM directions to generate, the result could be an inflated estimate of reserves on the PJM system, if the generator does not have back up fuel. Gas units should be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement.

99 Nomination deadlines approved in FERC order No. 809 implemented April 1, 2016.

PJM requires real-time situational awareness of the availability of all generators, including gas-fired generators, during the operating day, in order to operate the system effectively including knowledge of the level of available reserves. 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.

Types of Marginal Resources

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

Table 3-67 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2022, coal units were 10.7 percent and natural gas units were 74.3 percent of marginal resources. In the first nine months of 2022, natural gas combined cycle units were 60.4 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 the total marginal resources. In the first nine months of 2021, natural gas combined cycle units were 60.9 percent of the total marginal resources. In the first nine months of 2022, 55.8 percent of the wind marginal units had negative offer prices, 39.1 percent had zero offer prices and 5.1 percent of the wind marginal units had positive offer prices. In the first nine months of 2021, 77.8 percent of the wind marginal units had negative offer prices, 20.8 percent had zero offer prices and 1.4 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 0.81 percent in the first nine months of 2021 to 0.45 percent in the first nine months of 2022. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-67 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

Table 3-67 Type of fuel used and technology (By real-time marginal units): January through September, 2018 through 2022[100]

		2022 (Jan - Sep)				
Fuel	Technology	2018	2019	2020	2021	2022
Gas	CC	52.58%	60.79%	66.03%	60.87%	60.40%
Gas	CT	7.19%	6.38%	5.74%	8.57%	11.53%
Wind	Wind	2.78%	2.92%	5.64%	8.90%	10.86%
Coal	Steam	29.71%	26.32%	17.30%	16.87%	10.73%
Oil	CT	2.88%	0.47%	1.11%	1.05%	2.61%
Gas	Steam	1.91%	1.28%	1.84%	1.08%	1.46%
Other	Solar	0.09%	0.08%	0.40%	1.03%	0.90%
Gas	RICE	0.42%	0.00%	0.30%	0.53%	0.87%
Uranium	Steam	1.06%	1.17%	1.46%	0.81%	0.45%
Other	Steam	0.19%	0.07%	0.04%	0.10%	0.05%
Oil	RICE	0.52%	0.00%	0.03%	0.05%	0.04%
Oil	CC	0.17%	0.02%	0.00%	0.03%	0.04%
Municipal Waste	Steam	0.04%	0.02%	0.01%	0.01%	0.03%
Oil	Steam	0.39%	0.03%	0.07%	0.09%	0.02%
Municipal Waste	RICE	0.04%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	CT	0.00%	0.01%	0.01%	0.01%	0.00%
Municipal Waste	CT	0.02%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 3-48 shows the type of fuel used by marginal resources in the real-time energy market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

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

Figure 3-48 Type of fuel used (By real-time marginal units): January through September, 2004 through 2022

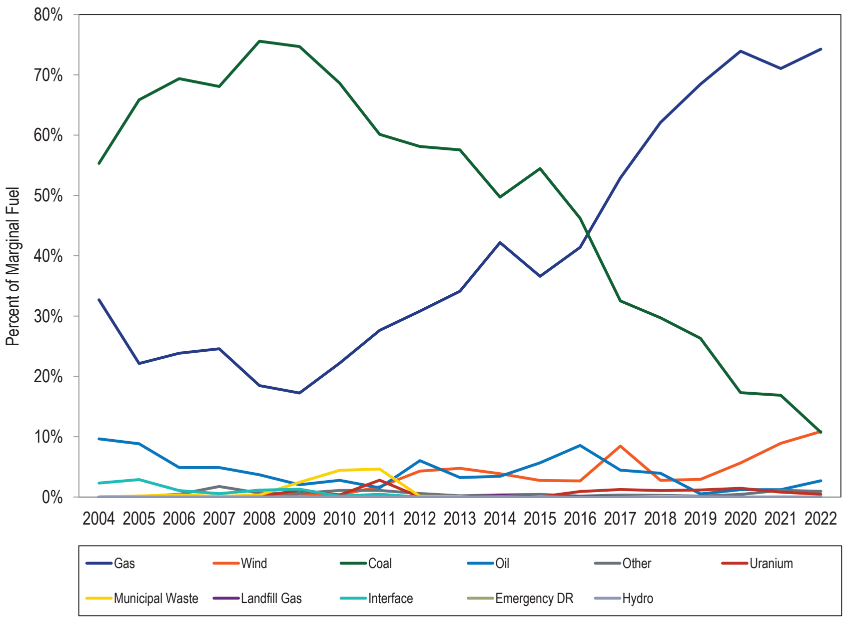


Table 3-68 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in the first nine months of 2022. In the first nine months of 2022, marginal fast start resources accounted for 7.90 percent of all marginal resources in the pricing run.

Table 3-68 Fuel type and technology (Real-time marginal units and fast start marginal units): January through September, 2022

		2022 (Jan - Sep)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	10.73%	10.73%
Gas	CC	0.00%	60.40%	60.40%
Gas	CT	6.17%	5.36%	11.53%
Gas	RICE	0.80%	0.08%	0.87%
Gas	Steam	0.00%	1.46%	1.46%
Municipal Waste	RICE	0.00%	0.00%	0.00%
Municipal Waste	Steam	0.00%	0.03%	0.03%
Oil	CC	0.00%	0.04%	0.04%
Oil	CT	0.75%	1.85%	2.61%
Oil	RICE	0.04%	0.00%	0.04%
Oil	Steam	0.00%	0.02%	0.02%
Other	Solar	0.00%	0.90%	0.90%
Other	Steam	0.00%	0.05%	0.05%
Uranium	Steam	0.00%	0.45%	0.45%
Wind	Wind	0.14%	10.72%	10.86%
All Marginal Units		7.90%	92.09%	100.00%

Table 3-69 shows the fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In the first nine months of 2022, up to congestion transactions were 44.1 percent of marginal resources compared to 36.1 percent in the first nine months of 2021. In the first nine months of 2022, virtual transactions were 83.2 percent of marginal resources compared to 79.9 percent in the first nine months of 2021.[101]

101 The data for the January through September, 2022 period is from the pricing run.

Table 3-69 Day-ahead marginal resources by type/fuel used and technology: January through September, 2018 through 2022

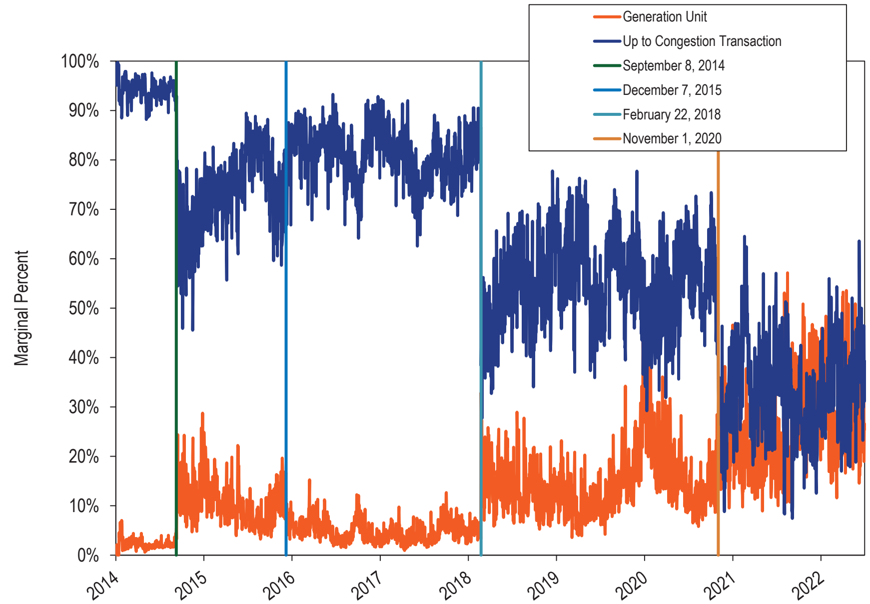
		(Jan - Sep)				
Type/Fuel	Technology	2018	2019	2020	2021	2022
Up to Congestion Transaction	NA	63.90%	57.70%	53.81%	36.14%	44.11%
DEC	NA	16.06%	18.41%	17.64%	26.50%	20.85%
INC	NA	9.24%	12.86%	12.41%	17.30%	18.25%
Gas	CC	5.08%	5.92%	9.90%	11.62%	10.23%
Coal	Steam	4.57%	4.23%	4.83%	6.32%	3.70%
Wind	Wind	0.16%	0.10%	0.24%	0.68%	0.99%
Gas	CT	0.20%	0.10%	0.24%	0.24%	0.59%
Gas	Steam	0.32%	0.39%	0.40%	0.52%	0.49%
Oil	CT	0.04%	0.04%	0.09%	0.06%	0.26%
Dispatchable Transaction	NA	0.13%	0.10%	0.08%	0.27%	0.23%
Gas	RICE	0.05%	0.04%	0.05%	0.12%	0.12%
Price Sensitive Demand	NA	0.02%	0.00%	0.00%	0.05%	0.06%
Other	Solar	0.03%	0.02%	0.01%	0.05%	0.05%
Oil	RICE	0.00%	0.00%	0.00%	0.01%	0.04%
Oil	CC	0.02%	0.00%	0.00%	0.01%	0.01%
Other	Steam	0.01%	0.01%	0.05%	0.03%	0.01%
Wind	Wind	0.00%	0.00%	0.00%	0.00%	0.01%
Municipal Waste	RICE	0.00%	0.01%	0.01%	0.03%	0.00%
Uranium	Steam	0.12%	0.06%	0.23%	0.03%	0.00%
Oil	Steam	0.05%	0.01%	0.01%	0.02%	0.00%
Municipal Waste	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-49 shows, for the day-ahead energy market from January 2014 through September 2022, the daily proportion of marginal resources that were up to congestion transactions or generation units. The UTC share increased from 36.1 percent in the first nine months of 2021 to 44.1 percent in the first nine months of 2022.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020,[102] but increased in the first nine months of 2022. 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.

102 172 FERC ¶ 61,046 (2020).

Figure 3-49 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2022



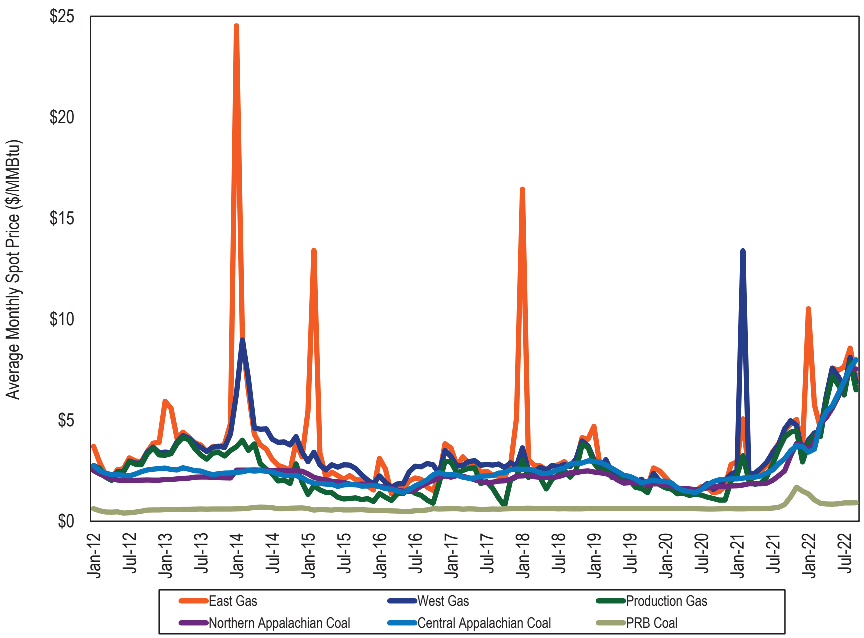
Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-50 shows fuel prices in PJM for 2012 through the first nine months of 2022. Eastern natural gas prices, coal prices, and oil prices increased in 2022 compared to 2021. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM and a number of new combined cycle plants have located in the production area since 2016. In

2022, the price of production gas was 120.1 percent higher than in 2021, the price of eastern natural gas was 121.2 percent higher and the price of western natural gas was 46.3 percent higher. The price of Northern Appalachian coal was 187.5 percent higher; the price of Central Appalachian coal was 138.6 percent higher; and the price of Powder River Basin coal was 45.5 percent higher.[103] The price of Northern Appalachian coal is the highest it has been in at least 20 years. The price of Central Appalachian coal is the highest it has been since 2008. The price of ULSD NY Harbor Barge was 103.2 percent higher in 2022 than in 2021.

Figure 3-50 Spot average fuel price comparison: 2012 through September 2022 ($/MMBtu)



103 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Table 3-70 compares the PJM real-time fuel-cost adjusted load-weighted average LMP in the first nine months of 2022 to the load-weighted average LMP in the first nine months of 2021.[104] The real-time load-weighted average LMP in the first nine months of 2022 increased by $42.16 per MWh or 118.2 percent from the real-time load-weighted average LMP in the first nine months of 2021. The real-time load-weighted average LMP for the first nine months of 2022 was 34.6 percent higher than the real-time fuel-cost adjusted load-weighted average LMP for the first nine months of 2022. The real-time fuel-cost adjusted load-weighted average LMP for the first nine months of 2022 was 62.1 percent higher than the real-time load-weighted average LMP for the first nine months of 2021. If fuel and emissions costs in the first nine months of 2022 had been the same as in the first nine months of 2021, holding the market dispatch constant, the real-time load-weighted average LMP in the first nine months of 2022 would have been lower, $57.82 per MWh, than the observed $77.84 per MWh.

A significant portion, 47.5 percent, of the increase in real-time load-weighted average LMP, $20.02 per MWh out of $42.16 per MWh, is directly attributable to fuel costs. Contributors to the other $22.14 per MWh are increased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, emissions costs, and higher markups. The result of holding the 2022 market dispatch constant includes the dispatch of units in 2022 that did not run in 2021 due to very high gas costs.

The fuel-cost adjusted load-weighted average LMP includes fuel costs associated with amortized start up and no load offers of the marginal fast start units in the pricing run.

Table 3-70 Real-time fuel-cost adjusted load-weighted average LMP (Dollars per MWh): January through September, 2021 and 2022

	2022 Fuel-Cost Adjusted Load-Weighted LMP	2022 Load-Weighted LMP	Change	Percent Change
Average	$57.82	$77.84	$20.02	34.6%
	2021 Load-Weighted LMP	2022 Fuel-Cost Adjusted Load-Weighted LMP	Change	Percent Change
Average	$35.68	$57.82	$22.14	62.1%
	2021 Load-Weighted LMP	2022 Load-Weighted LMP	Change	Change
Average	$35.68	$77.84	$42.16	118.2%

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

Table 3-71 shows the impact of each fuel type on the difference between the fuel-cost adjusted load-weighted average LMP and the load-weighted average LMP in the first nine months of 2022. Table 3-71 shows that higher natural gas prices explain 89.8 percent of the fuel-cost related increase in the real-time annual load-weighted average LMP in the first nine months of 2022 from the first nine months of 2021.

Table 3-71 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: 2022 adjusted to 2021 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted Load Weighted LMP	Percent
Gas	$17.98	89.8%
Coal	$1.76	8.8%
Oil	$0.28	1.4%
Other	$0.00	0.0%
Total	$20.02	100.0%

Components of LMP

Components of Real-Time Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and up to fourteen minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, New Jersey, and Virginia.[105] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. When generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. The component, ancillary service redispatch cost, shows the contribution of this cost to the PJM's load weighted LMP. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.[106]

Starting on September 1, 2021, the components shown in Table 3-72 and Table 3-73 are from the pricing run which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-72, including markup using unadjusted cost-based offers.[107] Table 3-72 shows that 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 2.2 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -5.0 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 8.9 percent of the load weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no cheaper generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. In the first nine months of 2022, 5.4 percent of the load-weighted LMP was the result of transmission

105 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021.

106 Scarcity component includes ancillary service redispatch cost component during periods of scarcity.

107 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

penalty factors affecting LMPs. The percent contribution of transmission penalty factors has increased substantially since PJM removed the constraint relaxation logic and allowed penalty factors to affect LMPs starting in February 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first nine months of 2022 and 2021.

Table 3-72 Components of real-time (Unadjusted) load-weighted average LMP: January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$19.23	53.9%	$43.15	55.4%	1.5%
Positive Markup	$3.10	8.7%	$6.94	8.9%	0.2%
Coal	$4.24	11.9%	$6.06	7.8%	(4.1%)
Ten Percent Adder	$2.35	6.6%	$4.95	6.4%	(0.2%)
Transmission Constraint Penalty Factor	$3.08	8.6%	$4.18	5.4%	(3.3%)
NO_x Cost	$0.25	0.7%	$3.03	3.9%	3.2%
Variable Maintenance	$1.20	3.4%	$2.26	2.9%	(0.5%)
NA	$0.96	2.7%	$1.97	2.5%	(0.2%)
CO_2 Cost	$0.99	2.8%	$1.74	2.2%	(0.5%)
Opportunity Cost Adder	$0.13	0.4%	$1.69	2.2%	1.8%
Scarcity	$0.25	0.7%	$1.40	1.8%	1.1%
Market-to-Market	$0.06	0.2%	$1.05	1.3%	1.2%
Variable Operations	$0.85	2.4%	$0.96	1.2%	(1.1%)
Oil	$0.27	0.8%	$0.85	1.1%	0.3%
Ancillary Service Redispatch Cost	$0.29	0.8%	$0.77	1.0%	0.2%
LPA Rounding Difference	$0.10	0.3%	$0.65	0.8%	0.5%
Increase Generation Differential	$0.10	0.3%	$0.20	0.3%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.03	0.0%	0.0%
Other	$0.01	0.0%	$0.02	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	$0.09	0.3%	($0.04)	(0.0%)	(0.3%)
Decrease Generation Differential	($0.03)	(0.1%)	($0.04)	(0.1%)	0.0%
Renewable Energy Credits	($0.00)	(0.0%)	($0.11)	(0.1%)	(0.1%)
Negative Markup	($1.86)	(5.2%)	($3.87)	(5.0%)	0.2%
Total	$35.68	100.0%	$77.84	100.0%	0.0%

Components of LMP Increase in 2022

In the first nine months of 2022, the real-time load-weighted average LMP increased by $42.16 per MWh, 118.2 percent, from the first nine months of 2021. Most of the increase is due to the $26.45 per MWh increase in the fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations), 62.7 percent of the increase in LMP. The emissions cost components of LMP (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) increased by $4.98 per MWh, 11.8 percent of the increase in LMP, mostly due to high NO_X prices during the summer. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased $5.49 per MWh, 13.0 percent of the increase in LMP. The remaining 12.4 percent of the LMP increase includes a $1.10 per MWh (2.6 percent) increase in the effect of the transmission constraint penalty factor on prices and a $1.15 per MWh (2.7 percent) increase in the scarcity component, which is the marginal cost of the market dispatching reserves, including shortage pricing.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-72 and Table 3-76) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-73 and Table 3-77), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-73, including markup using adjusted cost-based offers.

Table 3-73 Components of real-time (Adjusted) load-weighted average LMP: January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$19.23	53.9%	$43.15	55.4%	1.5%
Positive Markup	$4.41	12.4%	$9.88	12.7%	0.3%
Coal	$4.24	11.9%	$6.06	7.8%	(4.1%)
Transmission Constraint Penalty Factor	$3.08	8.6%	$4.18	5.4%	(3.3%)
NO_x Cost	$0.25	0.7%	$3.03	3.9%	3.2%
Variable Maintenance	$1.20	3.4%	$2.26	2.9%	(0.5%)
NA	$0.96	2.7%	$1.97	2.5%	(0.2%)
CO_2 Cost	$0.99	2.8%	$1.74	2.2%	(0.5%)
Opportunity Cost Adder	$0.13	0.4%	$1.69	2.2%	1.8%
Scarcity	$0.25	0.7%	$1.40	1.8%	1.1%
Market-to-Market	$0.06	0.2%	$1.05	1.3%	1.2%
Variable Operations	$0.85	2.4%	$0.96	1.2%	(1.1%)
Oil	$0.27	0.8%	$0.85	1.1%	0.3%
Ancillary Service Redispatch Cost	$0.29	0.8%	$0.77	1.0%	0.2%
LPA Rounding Difference	$0.10	0.3%	$0.65	0.8%	0.5%
Increase Generation Differential	$0.10	0.3%	$0.20	0.3%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.03	0.0%	0.0%
Other	$0.01	0.0%	$0.02	0.0%	0.0%
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	$0.09	0.3%	($0.04)	(0.0%)	(0.3%)
Decrease Generation Differential	($0.03)	(0.1%)	($0.04)	(0.1%)	0.0%
Renewable Energy Credits	($0.00)	(0.0%)	($0.11)	(0.1%)	(0.1%)
Negative Markup	($0.82)	(2.3%)	($1.85)	(2.4%)	(0.1%)
Total	$35.68	100.0%	$77.84	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-74, including markup using unadjusted cost-based offers for the first nine months of 2022. In the first nine months of 2022, 3.1 percent of the load-weighted average LMP was the result of commitment costs. The majority of the commitment costs in LMP were fuel costs in the no load component of offers for gas-fired fast start units. The second largest component was maintenance costs.

Table 3-74 Commitment cost related components of real-time (Unadjusted) load-weighted average LMP: January through September, 2022

	Start Cost Components		No Load Components		Other Components		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
Gas	$0.00	0.0%	$1.71	2.2%	$41.44	53.2%	$43.15	55.4%
Postive Markup	$0.06	0.1%	$0.00	0.0%	$6.88	8.8%	$6.94	8.9%
Coal	$0.00	0.0%	$0.00	0.0%	$6.06	7.8%	$6.06	7.8%
Ten Percent Adder	$0.03	0.0%	$0.16	0.2%	$4.76	6.1%	$4.95	6.4%
Transmission Constraint Penalty Factor	$0.00	0.0%	$0.00	0.0%	$4.18	5.4%	$4.18	5.4%
NO_x Cost	$0.02	0.0%	$0.20	0.3%	$2.81	3.6%	$3.03	3.9%
Variable Maintenance	$0.32	0.4%	$0.03	0.0%	$1.91	2.5%	$2.26	2.9%
NA	$0.00	0.0%	$0.00	0.0%	$1.97	2.5%	$1.97	2.5%
CO_2 Cost	$0.00	0.0%	$0.02	0.0%	$1.71	2.2%	$1.74	2.2%
Opportunity Cost Adder	$0.00	0.0%	$0.00	0.0%	$1.69	2.2%	$1.69	2.2%
Scarcity	$0.00	0.0%	$0.00	0.0%	$1.40	1.8%	$1.40	1.8%
Market-to-Market	$0.00	0.0%	$0.00	0.0%	$1.05	1.3%	$1.05	1.3%
Variable Operations	$0.00	0.0%	$0.00	0.0%	$0.96	1.2%	$0.96	1.2%
Oil	$0.00	0.0%	$0.05	0.1%	$0.80	1.0%	$0.85	1.1%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.00	0.0%	$0.77	1.0%	$0.77	1.0%
LPA Rounding Difference	$0.00	0.0%	$0.00	0.0%	$0.65	0.8%	$0.65	0.8%
Increase Generation Differential	$0.00	0.0%	$0.00	0.0%	$0.20	0.3%	$0.20	0.3%
Landfill Gas	$0.00	0.0%	$0.00	0.0%	$0.03	0.0%	$0.03	0.0%
Other	$0.00	0.0%	$0.00	0.0%	$0.02	0.0%	$0.02	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
LPA-SCED Differential	$0.00	0.0%	$0.00	0.0%	($0.04)	(0.0%)	($0.04)	(0.0%)
Decrease Generation Differential	$0.00	0.0%	$0.00	0.0%	($0.04)	(0.1%)	($0.04)	(0.1%)
Renewable Energy Credits	$0.00	0.0%	$0.00	0.0%	($0.11)	(0.1%)	($0.11)	(0.1%)
Negative Markup	($0.11)	(0.1%)	($0.07)	(0.1%)	($3.68)	(4.7%)	($3.87)	(5.0%)
Total	$0.31	0.4%	$2.10	2.7%	$75.42	96.9%	$77.84	100.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-75, including markup using unadjusted cost-based offers for the first nine months of 2022.

Table 3-75 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through September, 2022

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$40.17	54.9%	$43.15	55.4%	0.6%
Positive Markup	$6.73	9.2%	$6.94	8.9%	(0.3%)
Coal	$6.65	9.1%	$6.06	7.8%	(1.3%)
Ten Percent Adder	$4.61	6.3%	$4.95	6.4%	0.1%
Transmission Constraint Penalty Factor	$4.67	6.4%	$4.18	5.4%	(1.0%)
NO_x Cost	$2.49	3.4%	$3.03	3.9%	0.5%
Variable Maintenance	$1.64	2.2%	$2.26	2.9%	0.7%
NA	$1.36	1.9%	$1.97	2.5%	0.7%
CO_2 Cost	$1.77	2.4%	$1.74	2.2%	(0.2%)
Opportunity Cost Adder	$1.33	1.8%	$1.69	2.2%	0.4%
Scarcity	$1.61	2.2%	$1.40	1.8%	(0.4%)
Market-to-Market	$0.95	1.3%	$1.05	1.3%	0.0%
Variable Operations	$0.87	1.2%	$0.96	1.2%	0.1%
Oil	$0.49	0.7%	$0.85	1.1%	0.4%
Ancillary Service Redispatch Cost	$0.66	0.9%	$0.77	1.0%	0.1%
LPA Rounding Difference	$0.61	0.8%	$0.65	0.8%	(0.0%)
Increase Generation Differential	$0.21	0.3%	$0.20	0.3%	(0.0%)
Landfill Gas	$0.02	0.0%	$0.03	0.0%	0.0%
Other	$0.02	0.0%	$0.02	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.03)	(0.0%)	($0.04)	(0.0%)	(0.0%)
Decrease Generation Differential	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.0%)
Renewable Energy Credits	($0.11)	(0.2%)	($0.11)	(0.1%)	0.0%
Negative Markup	($3.47)	(4.7%)	($3.87)	(5.0%)	(0.2%)
Total	$73.23	100.0%	$77.84	100.0%	0.0%

Components of Day-Ahead Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

PJM implemented fast start pricing on September 1, 2021 in the day-ahead market as well. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. Since PJM uses LMPs generated in the pricing run as settlement LMPs, in Table 3-76 and Table 3-77, the components of day-ahead load-weighted average LMP in the first nine months of 2022 are calculated using marginal resource and sensitivity factor data from the pricing run and original data is used in the first nine months of 2021.

Table 3-76 shows the components of the PJM day-ahead annual load-weighted average LMP. In the first nine months of 2022, 22.2 percent of the load-weighted LMP was the result of gas costs, 7.4 percent of the load-weighted LMP was the result of coal costs, 30.2 percent was the result of DECs, 22.0 percent was the result of INCs, 2.4 percent was the result of UTCs and 5.7 percent was the result of positive markup.[108]

108 May 21, 2022 HE 1700, September 15, 2022 HE 0200, and September 21, 2022 HE 1500 had abnormal unit participant factor (UPF) values and the marginal resources data in that hour was removed from 2022 pricing run data for the calculations here.

Table 3-76 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$10.48	29.5%	$23.28	30.2%	0.7%
Gas	$9.44	26.6%	$17.09	22.2%	(4.4%)
INC	$4.66	13.1%	$16.93	22.0%	8.9%
Coal	$4.51	12.7%	$5.66	7.4%	(5.4%)
Positive Markup	$1.82	5.1%	$4.42	5.7%	0.6%
Dispatchable Transaction	$0.59	1.7%	$2.60	3.4%	1.7%
Ten Percent Adder	$1.40	3.9%	$2.08	2.7%	(1.2%)
Up to Congestion Transaction	$0.92	2.6%	$1.82	2.4%	(0.2%)
NO_x Cost	$0.25	0.7%	$1.35	1.8%	1.1%
CO_2 Cost	$0.72	2.0%	$1.06	1.4%	(0.7%)
Variable Maintenance	$0.77	2.2%	$0.84	1.1%	(1.1%)
Variable Operations	$0.72	2.0%	$0.49	0.6%	(1.4%)
Price Sensitive Demand	$0.16	0.4%	$0.32	0.4%	(0.0%)
Oil	$0.17	0.5%	$0.14	0.2%	(0.3%)
Opportunity Cost Adder	$0.01	0.0%	$0.08	0.1%	0.1%
Municipal Waste	$0.01	0.0%	$0.02	0.0%	(0.0%)
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Station Service Charges	($0.00)	(0.0%)	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.13)	(0.4%)	($0.17)	(0.2%)	0.2%
Negative Markup	($0.98)	(2.8%)	($1.15)	(1.5%)	1.3%
NA	$0.00	0.0%	$0.11	0.1%	0.1%
Total	$35.51	100.0%	$76.97	100.0%	(0.0%)

Table 3-77 shows the components of the PJM day-ahead annual load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

Table 3-77 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$10.48	29.5%	$23.28	30.2%	0.7%
INC	$4.66	13.1%	$16.93	22.0%	8.9%
Gas	$9.26	26.1%	$16.66	21.7%	(4.4%)
Positive Markup	$2.91	8.2%	$6.38	8.3%	0.1%
Coal	$4.48	12.6%	$5.62	7.3%	(5.3%)
Dispatchable Transaction	$0.59	1.7%	$2.60	3.4%	1.7%
Up to Congestion Transaction	$0.92	2.6%	$1.82	2.4%	(0.2%)
NO_x Cost	$0.24	0.7%	$1.34	1.7%	1.1%
CO_2 Cost	$0.72	2.0%	$1.03	1.3%	(0.7%)
Variable Maintenance	$0.76	2.1%	$0.83	1.1%	(1.1%)
Variable Operations	$0.71	2.0%	$0.48	0.6%	(1.4%)
Price Sensitive Demand	$0.16	0.4%	$0.32	0.4%	(0.0%)
Oil	$0.17	0.5%	$0.14	0.2%	(0.3%)
Opportunity Cost Adder	$0.01	0.0%	$0.08	0.1%	0.1%
Municipal Waste	$0.01	0.0%	$0.02	0.0%	(0.0%)
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Station Service Charges	($0.00)	(0.0%)	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Ten Percent Adder	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Wind	($0.13)	(0.4%)	($0.17)	(0.2%)	0.2%
Negative Markup	($0.43)	(1.2%)	($0.50)	(0.6%)	0.6%
NA	$0.00	0.0%	$0.11	0.1%	0.1%
Total	$35.51	100.0%	$76.97	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021 and amortized startup cost and no load cost were included in the price offers of fast start marginal units. The commitment cost related components of LMP reflect the amortized startup cost and no load cost of the fast start marginal units. Table 3-78 shows that in the first nine months of 2022, 0.4 percent of the load-weighted average LMP was the result of commitment costs using unadjusted cost-based offers.

Table 3-78 Commitment cost related components of day-ahead (Unadjusted) load-weighted average LMP: January through September, 2022

	Commitment		Other		All Generation		Virtuals and Transactions		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
DEC	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$23.28	30.2%	$23.28	30.2%
Gas	$0.23	0.3%	$16.86	21.9%	$17.09	22.2%	$0.00	0.0%	$17.09	22.2%
INC	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$16.93	22.0%	$16.93	22.0%
Coal	$0.00	0.0%	$5.66	7.4%	$5.66	7.4%	$0.00	0.0%	$5.66	7.4%
Positive Markup	$0.01	0.0%	$4.41	5.7%	$4.42	5.7%	$0.00	0.0%	$4.42	5.7%
Dispatchable Transaction	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$2.60	3.4%	$2.60	3.4%
Ten Percent Adder	$0.03	0.0%	$2.05	2.7%	$2.08	2.7%	$0.00	0.0%	$2.08	2.7%
Up to Congestion Transaction	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$1.82	2.4%	$1.82	2.4%
NO_x Cost	$0.03	0.0%	$1.33	1.7%	$1.35	1.8%	$0.00	0.0%	$1.35	1.8%
CO_2 Cost	$0.00	0.0%	$1.05	1.4%	$1.06	1.4%	$0.00	0.0%	$1.06	1.4%
Variable Maintenance	$0.01	0.0%	$0.83	1.1%	$0.84	1.1%	$0.00	0.0%	$0.84	1.1%
Variable Operations	$0.00	0.0%	$0.49	0.6%	$0.49	0.6%	$0.00	0.0%	$0.49	0.6%
Price Sensitive Demand	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.32	0.4%	$0.32	0.4%
Oil	($0.00)	(0.0%)	$0.14	0.2%	$0.14	0.2%	$0.00	0.0%	$0.14	0.2%
Opportunity Cost Adder	$0.00	0.0%	$0.08	0.1%	$0.08	0.1%	$0.00	0.0%	$0.08	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	$0.02	0.0%	$0.00	0.0%	$0.02	0.0%
Other	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%	$0.00	0.0%	$0.01	0.0%
Station Service Charges	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Wind	$0.00	0.0%	($0.17)	(0.2%)	($0.17)	(0.2%)	$0.00	0.0%	($0.17)	(0.2%)
Negative Markup	($0.01)	(0.0%)	($1.14)	(1.5%)	($1.15)	(1.5%)	$0.00	0.0%	($1.15)	(1.5%)
NA	$0.00	0.0%	$0.00	0.0%	$0.11	0.1%	$0.00	0.0%	$0.11	0.1%
Total	$0.29	0.4%	$31.62	41.1%	$32.03	41.6%	$44.94	58.4%	$76.97	100.0%

Table 3-79 compares the components of LMP between the dispatch run and the pricing run for the first nine months of 2022. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. The dispatch run components of day-ahead load-weighted average LMP are calculated using the marginal resources and sensitivity factors from the dispatch run result and the pricing run components of day-ahead, load-weighted, average LMP are calculated using the marginal resources and sensitivity factors from the pricing run result. The marginal DEC contribution of day-ahead load-weighted LMP decreased by 0.4 percent, the marginal gas generation unit contribution of day-ahead load-weighted average LMP increased by 1.4 percent, the marginal INC contribution of day-ahead load-weighted average LMP increased by 0.6 percent from the dispatch run to the pricing run.

Table 3-79 Components of day-ahead (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through September, 2022

Element	Dispatch Run Contribution to LMP	Dispatch Run Percent	Pricing Run Contribution to LMP	Pricing Run Percent	Change in Percent
DEC	$23.54	30.6%	$23.28	30.2%	(0.4%)
Gas	$16.00	20.8%	$17.09	22.2%	1.4%
INC	$16.44	21.4%	$16.93	22.0%	0.6%
Coal	$7.00	9.1%	$5.66	7.4%	(1.8%)
Positive Markup	$5.42	7.1%	$4.42	5.7%	(1.3%)
Dispatchable Transaction	$1.17	1.5%	$2.60	3.4%	1.9%
Ten Percent Adder	$2.13	2.8%	$2.08	2.7%	(0.1%)
Up to Congestion Transaction	$2.24	2.9%	$1.82	2.4%	(0.6%)
NO_x Cost	$1.44	1.9%	$1.35	1.8%	(0.1%)
CO_2 Cost	$1.00	1.3%	$1.06	1.4%	0.1%
Variable Maintenance	$0.68	0.9%	$0.84	1.1%	0.2%
Variable Operations	$0.64	0.8%	$0.49	0.6%	(0.2%)
Price Sensitive Demand	$0.38	0.5%	$0.32	0.4%	(0.1%)
Oil	$0.05	0.1%	$0.14	0.2%	0.1%
Opportunity Cost Adder	$0.02	0.0%	$0.08	0.1%	0.1%
Municipal Waste	($0.02)	(0.0%)	$0.02	0.0%	0.0%
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Station Service Charges	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.17)	(0.2%)	($0.17)	(0.2%)	0.0%
Negative Markup	($1.17)	(1.5%)	($1.15)	(1.5%)	0.0%
NA	$0.00	0.0%	$0.11	0.1%	0.1%
Total	$76.81	100.0%	$76.97	100.0%	(0.0%)

Shortage

PJM's energy market experienced five minute shortage pricing for 62 five minute intervals on 17 days in the first nine months of 2022. PJM implemented fast start pricing on September 1, 2021. In the first nine months of 2022, there were 62 five minute intervals with shortage pricing in the pricing run, and 56 intervals with shortage in the dispatch run. Table 3-80 shows a summary of the number of days of the emergency alerts, warnings and actions that were declared in PJM in the first nine months of 2021 and 2022. In the first nine months of 2022, there were three emergency actions that triggered a Performance Assessment Interval (PAI). One of the days with shortage pricing, January 27, 2022, had a cold weather alert in effect. June 13, 2022, with several intervals of shortage, preceded the multiple emergency actions and alerts that began on June 14, 2022.

Table 3-80 Summary of emergency events declared: January through September, 2021 and 2022

Event Type	Number of days events declared 2021 (Jan - Sep)	Number of days events declared 2022 (Jan - Sep)
Cold Weather Alert	6	7
Hot Weather Alert	23	31
Maximum Emergency Generation Alert	0	1
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	3
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	3
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	10	17
Energy export recalls from PJM capacity resources	0	0

Figure 3-51 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months from 2013 through 2022.

Figure 3-51 Declared emergency alerts: January through September, 2013 through 2022

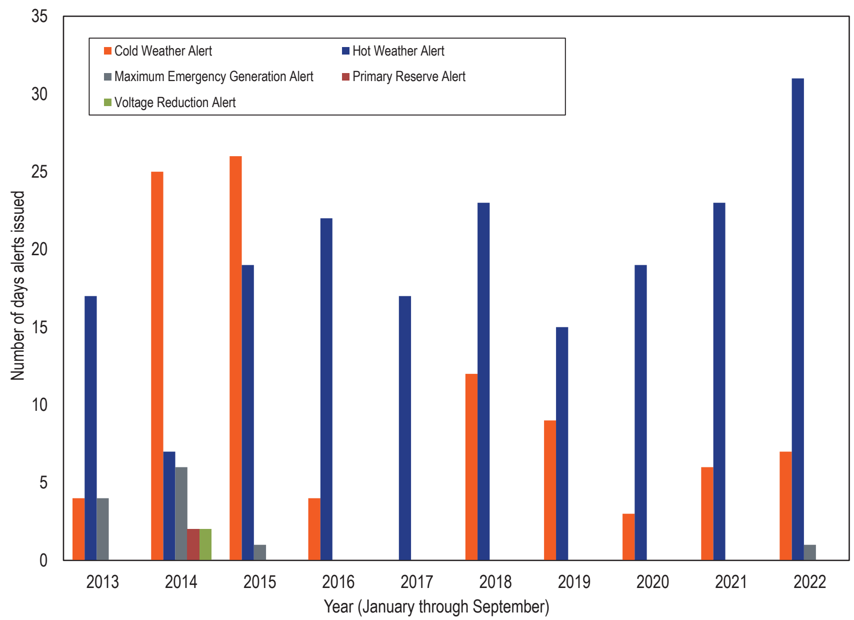
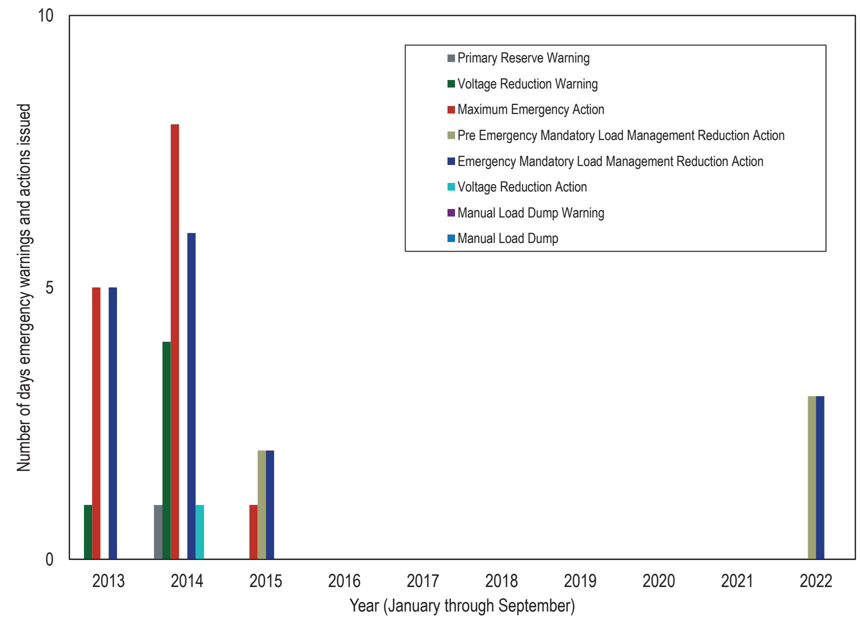


Figure 3-52 shows the number of days that emergency warnings and actions were declared in PJM in the first nine months from 2013 through 2022.

Figure 3-52 Declared emergency warnings and actions: January through September, 2013 through 2022



Emergency Procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time, on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

Table 3-81 provides a description of PJM declared emergency procedures.[109] [110] [111] [112]

Table 3-81 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

109 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 3.3 Cold Weather Alert.
110 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 3.4 Hot Weather Alert.
111 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
112 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-82 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2022.

Table 3-82 Declared emergency alerts, warnings and actions: January through September, 2022

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
01/07/2022	COMED													
01/11/2022	Western													
01/21/2022	PJM RTO													
01/25/2022	COMED													
01/26/2022	Western													
01/27/2022	Western													
01/29/2022	Western													
05/20/2022		Mid-Atlantic, Southern												
05/21/2022		Mid-Atlantic, Southern												
05/31/2022		PJM RTO												
06/01/2022		Mid-Atlantic, Southern												
06/13/2022		EKPC												
06/14/2022		Western	AEP						AEP_MARION	AEP_MARION				AEP
06/15/2022		Western							AEP_MARION	AEP_MARION				AEP
06/16/2022		Western							AEP_MARION	AEP_MARION				
06/17/2022		Mid-Atlantic, Southern												
06/20/2022		COMED												
06/21/2022		Western												
06/22/2022		Western												
06/30/2022		PJM RTO												
07/01/2022		Western sans COMED												
07/05/2022		Western												
07/12/2022		Mid-Atlantic												
07/19/2022		Mid-Atlantic												
07/20/2022		PJM RTO												
07/21/2022		PJM RTO												
07/22/2022		PJM RTO												
07/23/2022		PJM RTO												
07/24/2022		PJM RTO												
07/28/2022		Mid-Atlantic, Southern												
08/02/2022		Mid-Atlantic, Southern												
08/03/2022		PJM RTO												
08/04/2022		Mid-Atlantic, Southern												
08/05/2022		Mid-Atlantic												
08/08/2022		Mid-Atlantic												
08/09/2022		Mid-Atlantic, Southern												
08/29/2022		Mid-Atlantic, Southern												
09/19/2022		Mid-Atlantic, Southern												

Power Balance Constraint Violation

On October 1, 2019, the power balance constraint was violated in 11 approved RT SCED solutions. On February 16, 2020, the power balance constraint was violated in one approved RT SCED solution which was used to set prices for three five minute intervals. On March 22, 2021, the power balance constraint was violated in one approved RT SCED solution. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM would convert reserves to energy before violating power balance. It is unclear whether and when PJM would use its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by ASO to energy to satisfy the power balance constraint.[113] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to shortage pricing.

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.

113 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

Table 3-83 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In 2021, there were three five minute intervals using an RT SCED solution with a violated power balance constraint. The average energy component of LMP in that five minute interval with artificially increased supply to satisfy the power balance constraint was $1,582.14 per MWh.[114] There were no violations in the first nine months of 2022.

Table 3-83 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP ($/MWh)
2013	-	$0.00
2014	655	$36.29
2015	71	($0.76)
2016	42	$93.06
2017	31	$279.86
2018	16	$268.21
2019	36	$845.48
2020	5	$351.56
2021	3	$1,582.14
2022 (Jan - Sep)	-	$0.00

Balancing Ratio for Local Emergency Events

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements in an area during an emergency event to the total committed capacity in the area. In the case of the PAIs declared in 2018 that were triggered due to transmission outages in limited locations, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response.[115] It is not appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by

114 The energy component of LMP, or the shadow price of the power balance constraint, is the incremental cost of meeting a one MWh increase in the system load.

115 See *2018 State of the Market Report for PJM*, Volume II, Section 3: Energy Market, at Scarcity, pp. 201 – 202.

defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. PJM calculated the balancing ratio for the localized load shed that occurred in the AEP Edison area in 2018 and used the average balancing ratio during the event to calculate the capacity market seller offer cap for all LDAs for the 2022/2023 Delivery Year.[116] These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends, 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.

Performance Assessment Intervals

PJM currently triggers a PAI any time it declares a pre-emergency load management reduction action, or a more severe emergency action.[117] PJM's trigger for PAI is subjective, and it should be based on a quantifiable, transparent metric of the need for capacity in the PJM system. For example, in ISO New England, under the Pay for Performance design, resources are assessed for performance during Capacity Scarcity Conditions ("CSCs") that occur when the system or local area is short on ten and thirty minute nonspinning reserves.[118] Reserve shortages are determined based on a predefined reserve requirement, and the reserve calculation that is embedded in the real-time dispatch tool.

The October 2, 2019, PAI provided actual data and evidence on the issues with PJM's triggers, and PJM's treatment of excused MW. The PAI on October 2, 2019, was triggered when PJM declared a pre-emergency load management reduction action in the AEP, BGE, Dominion and Pepco Zones based on anticipated high load relative to the available supply. The actual load was significantly lower than forecasted.[119]

On October 1, 2019, the day before the PAI, PJM did experience high load relative to the available supply. The system conditions were reflected in the market outcomes with multiple intervals of high prices, and reserve shortages.[120] The decision to declare a pre-emergency load management reduction action on October 2, 2019, was based on an expectation of the repetition of the events on October 1, 2019, which did not materialize. This illustrates the shortcomings of triggering PAIs based on PJM operator declared emergency actions or pre-emergency load management reduction, instead of using a quantitative metric that is readily available to PJM, such as reserves.[121] Given this implementation, it can no longer be assumed that PAI would occur when the PJM region, or a subset of zones in the PJM region are experiencing capacity shortage conditions.

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through high energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real-time reserves than required.

In the first nine months of 2022, there were 62 five minute intervals with shortage pricing that occurred on 17 days in PJM.

116 *See* PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), *which can be accessed at* <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?> .

117 OATT Definitions at "Emergency Action."

118 ISO New England Inc. Internal Market Monitor, "2018 Annual Markets Report," (May 23, 2019) at 156 (§ 6.2.2 (Pay-for-Performance Outcomes)).

119 In a report reviewing the PAI, PJM stated: "The most striking anomaly was load levels in the AEP and Mid-Atlantic zones that came in significantly below forecast." *See* PJM, "A Review of the October 2019 Performance Assessment Event," (2019) at 1, which can be accessed at <https://www.pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx>.

120 *See* Monitoring Analytics, LLC, *2019 State of the Market Report for PJM*, Volume II: Section 3 Energy Market at 176 –180 (Analysis of October 1 Events).

121 There are existing issues with the accuracy of reserve measurement in PJM, and they should also be resolved by improving generator modeling in the energy market.

With Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[122] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. PJM did not implement the rule as intended in Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes, from the previous three minutes. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC that incorporates integer relaxation for certain units deemed fast start by PJM. This can lead to differences between the dispatched reserves in RT SCED, and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred during seven intervals in the first nine months of 2022.[123]

122 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).
123 The seven intervals include a case in which both RTO and MAD were short in the pricing run but only MAD was short in the dispatch run.

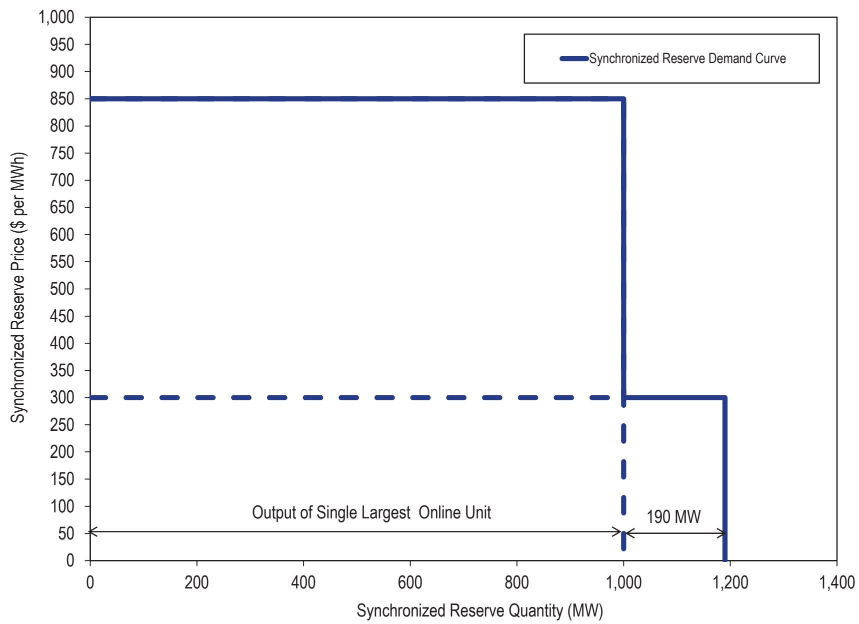
Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.[124]

Operating Reserve Demand Curves

Since July 12, 2017, the PJM synchronized reserve requirement in a reserve zone or a subzone is the actual output of the single largest online unit in that reserve zone or subzone. The primary reserve requirement in a reserve zone or a subzone is 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step is priced at $850 per MWh. The second step of the primary and synchronized reserve demand curves extends the primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-53 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

124 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21–30:14 (Oct. 28, 2014).

Figure 3-53 Real-time synchronized reserve demand curve showing the permanent second step



Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-53 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh.

The shortage prices set by the ORDC are added to LMP during shortages based on the marginal unit's ability to provide both energy and reserves. When multiple reserve products are short or when reserves are short in multiple zones, the ORDC prices are additive. Currently, the highest possible shortage penalty in LMP is $3,400 per MWh, which is the $850 per MWh price times four, for two reserve products (synchronized reserve and nonsynchronized reserve) times two reserve zones, RTO and MAD. However, PJM caps the system marginal energy price at $3,750, which is the sum of the highest possible energy offer, the synchronized reserve penalty factor, the primary reserve penalty factor, and a $50 per MWh threshold. The current market rules cap the additive reserve shortage penalty factors for the MAD synchronized reserve market clearing price to the sum of the synchronized reserve penalty factor and the primary reserve penalty factor, which is $1,700 per MW.[125] The $1,700 per MWh penalty applies any time PJM initiates a manual load dump action or voltage reduction action.[126]

Energy and Reserve Price Caps

Table 3-84 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone, and the RTO to MAD reserve transfer constraint is not binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price.

In scenario C, the sum of the reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,750 per MWh, so SMP

125 *See* PJM Operating Agreement, Schedule 1, Section 3.2.3A(d)(ii). The cap on the additive reserve shortage penalty factors in MAD was not reflected in the prior report and the maximum in MAD was therefore overstated. See: *2020 Quarterly State of the Market Report for PJM: January through September*, p. 192.

126 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 121 (July 7, 2022), 2.8 The Calculation of Locational Marginal Prices (LMPs) During Emergency Procedures.

capping is triggered whether the marginal unit for energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of all four reserve penalty factors only triggers SMP capping if the marginal unit for energy can serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,750 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[127]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in the $1,700 per MWh scarcity adder, and a violated transmission constraint with $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

Table 3-84 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

Scenario	Marginal Unit Offer Price	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Transmission Constraint Penalty Factor in SMP	System Marginal Price		Transmission Constraint Penalty Factor in CLMP	Total LMP	
		RTO	MAD	RTO	MAD		RTO Marginal	MAD Marginal		RTO Marginal	MAD Marginal
A	$50	$850	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$1,750	$3,450	$0	$1,750	$3,450
C	$50	$850	$850	$850	$850	$2,000	$3,750	$3,750	$0	$3,750	$3,750
D	$1,000	$850	$850	$850	$850	$0	$2,700	$3,750	$0	$2,700	$3,750
E	$1,000	$850	$850	$850	$850	$2,000	$3,750	$3,750	$2,000	$5,750	$5,750
F	$2,000	$850	$850	$850	$850	$2,000	$3,750	$3,750	$2,000	$5,750	$5,750

Changes to the ORDC, previously approved by FERC and planned for implementation in 2022, were reversed by the Commission in an order issued on December 22, 2021.[128] These changes, if implemented, would have increased the price for reserve quantities less than the reserve requirement to $2,000 per MWh, and prices beyond the reserve requirement to levels that were based on an extended downward sloping ORDC, and the price cap would have been removed.[129]

Circuit Breaker

Due to the high prices that were possible under PJM's proposed ORDCs and the February 2021 experiences of market participants in the ERCOT market, PJM stakeholders initiated a discussion about a circuit breaker mechanism that would reduce prices in circumstances that would otherwise result in prolonged high LMPs. In the absence of an efficient shortage pricing mechanism, reducing the application of transmission constraint penalty factors and reducing reserve penalty prices during extended emergency situations would minimize the market harm done by administrative pricing without implementing an inefficient price capping process. While FERC's remand order maintains the current levels of emergency pricing, rather than PJM's higher proposed levels, there remain possible scenarios in which prolonged and excessively high administrative pricing in the energy market under the current tariff provisions would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market

127 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

128 177 FERC ¶ 61,209 (December 22, 2021).

129 See 171 FERC ¶ 61,153 (2020), *order on reh'g*, 173 FERC ¶ 61,123 (2020).

participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond. A better solution than a circuit breaker would be to lower the default emergency pricing levels to avoid inefficient wealth transfers.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions to, for example, commit more reserves when specific needs arise.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO Reserve Zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. On most days, the MAD Subzone is no longer relevant. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons, or the reserve need is modeled as an artificial closed loop interface with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies. On October 1, 2022, PJM has will begin implementing a process to revise the definition of the subzone. There will no longer be a MAD subzone. Instead, the subzone definition may change as often as daily based on system conditions.

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. Currently, spinning events are triggered by an all call message to the system requesting all online generation units to increase their energy output, regardless of whether a unit cleared for synchronized reserves. This deployment mechanism is used regardless of the actual MW needed to recover the Area Control Error (ACE) to zero or to the pre-event levels. Generally, the cause of the spinning event is a unit trip. Occasionally, PJM also declares spinning events to recover ACE when generators do not follow dispatch instructions to increase output. The response solicited through the all call message during a spinning event is much greater than the MW lost and MW needed to recover the ACE. This results in an overshoot of the ACE to positive values beyond the target range. There is currently no mechanism for PJM to selectively load synchronized reserves in proportion to the MW needed to recover ACE to zero or the pre-event levels, even though the PJM market rules allow PJM to load a proportion of reserves. While the all-call message signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements ten to fourteen minutes into the future. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions. PJM's instruction to generators is to ignore the dispatch signals sent by RT SCED, and instead continue to ramp their units up until the spin event ends. Since the LMPs do not reflect the need for the generators to ramp up their resources, until October 1, 2022, PJM paid a $50 per MWh premium to all resources, except Tier 2 cleared resources, that increased their output in response to a spinning event.

Under the reserve market enhancements that began October 1, 2022, all synchronized reserves are treated as a uniform product and paid the market clearing price for synchronized reserves. All synchronized reserves are also assessed a penalty for nonperformance during the synchronized reserve events. Deployment of reserves during synchronized reserve events will be most efficient if the resources that are deployed and are subject to performance evaluation for their response are the resources that are committed as synchronized reserves. However, under PJM's proposed Intelligent Reserve Deployment (IRD) approach, PJM would rely on units that do not have a reserve commitment, while unnecessarily holding back committed and compensated reserve units during a spin event.[130] This is because the IRD approach is just a SCED solution based on: load increased by a predetermined amount; inflexible synchronized reserves converted to energy production; and maintaining the reserve requirement. The result is that inflexible synchronized reserves are converted to energy production, while flexible resources are held as reserves to meet the reserve requirement instead of responding to the spin event. Since PJM proposes penalties for lack of response during spin events for cleared and dispatched reserves, this results in inflexible synchronized reserve resources potentially being subject to penalties disproportionately, while flexible synchronized reserves may or may not be dispatched, and consequently may not be not subject to penalties. The IRD mechanism also creates a reliability risk since it relies on resources not committed as reserves to increase their output to recover ACE during a spin event, and these resources are not subject to a penalty for nonperformance. For these reasons, FERC rejected PJM's IRD proposal on August 15, 2022.[131]

While PJM recovers from a disturbance during a spinning event, PJM should also adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for, and are being used for their intended purpose. Without such an adjustment, RT SCED will have to depend on resources that are not deemed to be eligible for clearing as synchronized reserves to aid the recovery of ACE. Without such an adjustment, the prices will be artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed.

Reserve Shortages in 2022

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. For reliability reasons, and to maintain reserves to comply with NERC standards, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the minimum reserve requirement (MRR). To trigger shortage pricing, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[132] [133] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflects shortage pricing, and the rest of the solutions do not.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-85 shows, for each month of 2021 and the first nine months of 2022, the total number of target times, the number of target times for which at least one RT

130 PJM. "Intelligent Reserve Deployment PJM Package," presented at the Synchronous Reserve Deployment Task Force, (July 1, 2021) at 3, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210701/20210701-item-03-pjms-proposed-package-intelligent-reserve-deployment.ashx>.

131 *See* PJM Interconnection, L.L.C., 180 FERC ¶ 61,089 (August 15, 2022).

132 A case is executed when it begins to solve. Most but not all cases are solved. RT SCED cases take about one to two minutes to solve.

133 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. This resulted in an increase in RT SCED cases with reserve shortages in at least one of the solutions. Table 3-85 shows that, in the first nine months of 2022, 8,033 target times, or 10.2 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 2,261 target times, or 2.9 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first nine months of 2021, there were 2,735 target times, or 3.4 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 737 target times, or 0.9 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

Table 3-85 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2021 through September 2022

Year, Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2021 Jan	8,928	114	1.3%	22	0.2%	0	0.0%
2021 Feb	8,064	108	1.3%	28	0.3%	0	0.0%
2021 Mar	8,916	198	2.2%	46	0.5%	4	2.0%
2021 Apr	8,640	130	1.5%	24	0.3%	0	0.0%
2021 May	8,928	235	2.6%	48	0.5%	5	2.1%
2021 Jun	8,640	516	6.0%	165	1.9%	1	0.2%
2021Jul	8,928	460	5.2%	104	1.2%	0	0.0%
2021 Aug	8,928	429	4.8%	131	1.5%	7	1.6%
2021 Sep	8,640	545	6.3%	169	2.0%	2	0.4%
2021 Oct	8,928	730	8.2%	232	2.6%	2	0.3%
2021 Nov	8,652	1,320	15.3%	405	4.7%	4	0.3%
2021 Dec	8,928	805	9.0%	198	2.2%	3	0.4%
2021 Total	105,120	5,590	5.3%	1,572	1.5%	28	0.5%
2022 Jan	8,928	904	10.1%	276	3.1%	14	1.5%
2022 Feb	8,064	544	6.7%	153	1.9%	0	0.0%
2022 Mar	8,916	1,306	14.6%	381	4.3%	5	0.4%
2022 Apr	8,640	1,114	12.9%	343	4.0%	3	0.3%
2022 May	8,928	1,008	11.3%	265	3.0%	1	0.1%
2022 Jun	8,640	714	8.3%	170	2.0%	38	5.3%
2022 Jul	8,928	785	8.8%	223	2.5%	1	0.1%
2022 Aug	8,928	927	10.4%	263	2.9%	0	0.0%
2022 Sep	8,640	731	8.5%	187	2.2%	0	0.0%
2022 Total	78,612	8,033	10.2%	2,261	2.9%	62	0.8%

In the first nine months of 2022, there were 62 five minute intervals with shortage pricing, while there were 2,261 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In the first nine months of 2021, there were 19 five minute intervals with shortage pricing, while 737 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM 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. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

There were 62 five minute intervals with shortage pricing in the first nine months of 2022, compared to 19 intervals in the first nine months of 2021. PJM implemented fast start pricing on September 1, 2021. This resulted in differences in reserve shortages between the dispatch run and the pricing run in the first nine months of 2022. In the first nine months of 2022, there were 62 five minute intervals with shortage pricing in the pricing run, and 56 intervals with shortage in the dispatch run.

Table 3-86 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 62 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2022. Table 3-86 shows that 30 out of the 33 intervals had synchronized reserve shortage for the RTO reserve zone in the dispatch run. Table 3-87 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the 29 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2022. Table 3-87 shows that all 29 intervals had synchronized reserve shortage for the MAD Subzone in both the dispatch run and pricing run with identical capped market clearing prices.

Table 3-88 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the 36 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2022. Table 3-88 shows that in 3 out of the 36 intervals there was no shortage of primary reserves in the dispatch run. Table 3-89 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the 33 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2022.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD Reserve Subzone is inside the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[134] The synchronized reserve clearing price of the MAD Reserve Subzone is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

134 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.

Table 3-86 Real-time RTO synchronized reserve shortage intervals: January through September, 2022

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)
13-Jan-22 06:25	1,796.0	1,396.8	399.234	$2,569.7	$1,700.0	1,796.0	1,396.8	399.234	$2,569.7	$1,700.0
13-Jan-22 06:30	1,812.0	1,310.7	501.260	$2,087.2	$1,700.0	1,812.0	1,310.7	501.260	$2,087.2	$1,700.0
16-Jan-22 16:35	1,859.0	1,669.0	190.000	$401.3	$401.3	1,859.0	1,669.0	190.000	$401.3	$401.3
30-Jan-22 01:45	1,786.0	1,670.4	115.649	$300.0	$300.0	1,786.0	1,670.4	115.649	$300.0	$300.0
30-Jan-22 01:50	1,815.0	1,738.8	76.180	$300.0	$300.0	1,815.0	1,738.8	76.180	$300.0	$300.0
31-Jan-22 06:35	1,690.0	1,248.3	441.679	$1,728.6	$1,700.0	1,690.0	1,248.3	441.679	$1,689.5	$1,689.5
31-Jan-22 06:40	1,692.0	1,566.4	125.611	$346.6	$346.6	1,692.0	1,566.4	125.611	$346.6	$346.6
31-Jan-22 06:45	1,700.0	1,700.0	0.000	$313.3	$313.3	1,700.0	1,700.0	0.000	$235.4	$235.4
31-Jan-22 06:55	1,774.0	1,774.0	0.000	$313.3	$313.3	1,774.0	1,774.0	0.000	$281.5	$281.5
02-Mar-22 17:25	1,641.0	1,525.0	115.996	$300.0	$300.0	1,641.0	1,525.0	115.996	$300.0	$300.0
02-Mar-22 17:30	1,638.0	1,448.0	190.000	$515.5	$515.5	1,638.0	1,448.0	190.000	$515.5	$515.5
12-Mar-22 10:20	1,825.0	1,708.1	116.856	$300.0	$300.0	1,825.0	1,708.1	116.856	$300.0	$300.0
20-Mar-22 19:40	1,642.0	1,636.2	5.840	$300.0	$300.0	1,642.0	1,636.2	5.840	$300.0	$300.0
21-Mar-22 06:40	1,722.0	1,722.0	0.000	$300.0	$300.0	1,722.0	1,722.0	0.000	$300.0	$300.0
13-Apr-22 17:30	1,534.7	1,450.5	84.248	$300.0	$300.0	1,534.7	1,450.5	84.248	$300.0	$300.0
14-Apr-22 09:35	1,533.7	1,459.9	73.782	$300.0	$300.0	1,533.7	1,459.9	73.782	$300.0	$300.0
19-Apr-22 11:15	1,536.1	1,536.1	0.000	$300.0	$300.0	1,536.1	1,536.1	0.000	$269.7	$269.7
16-May-22 15:55	1,789.0	1,680.1	108.911	$300.0	$300.0	1,789.0	1,680.1	108.911	$300.0	$300.0
13-Jun-22 15:00	1,766.0	1,580.0	186.017	$1,150.0	$1,150.0	1,766.0	1,580.0	186.017	$1,150.0	$1,150.0
13-Jun-22 15:05	1,765.0	1,758.5	6.466	$600.0	$600.0	1,765.0	1,758.5	6.466	$600.0	$600.0
13-Jun-22 16:00	1,766.0	1,707.8	58.206	$1,150.0	$1,150.0	1,766.0	1,707.8	58.206	$1,150.0	$1,150.0
13-Jun-22 16:05	1,764.0	1,649.5	114.499	$1,150.0	$1,150.0	1,764.0	1,649.5	114.499	$1,150.0	$1,150.0
13-Jun-22 16:15	1,768.0	1,768.0	0.000	$1,150.0	$1,150.0	1,768.0	1,768.0	0.000	$1,150.0	$1,150.0
13-Jun-22 16:25	1,768.0	1,726.7	41.734	$1,150.0	$1,150.0	1,768.0	1,726.7	41.734	$1,150.0	$1,150.0
13-Jun-22 16:30	1,770.0	1,727.6	42.408	$1,150.0	$1,150.0	1,770.0	1,727.6	42.408	$1,150.0	$1,150.0
13-Jun-22 16:35	1,771.0	1,771.0	0.000	$1,150.0	$1,150.0	1,771.0	1,771.0	0.000	$1,150.0	$1,150.0
13-Jun-22 16:45	1,770.0	1,679.7	90.362	$1,150.0	$1,150.0	1,770.0	1,679.7	90.362	$1,150.0	$1,150.0
13-Jun-22 16:50	1,770.0	1,770.0	0.000	$1,150.0	$1,150.0	1,770.0	1,770.0	0.000	$1,150.0	$1,150.0
13-Jun-22 17:45	1,765.0	1,739.2	25.792	$1,150.0	$1,150.0	1,765.0	1,739.2	25.792	$1,150.0	$1,150.0
27-Jun-22 17:05	1,792.0	1,602.0	190.000	$850.0	$850.0	1,792.0	1,602.0	190.000	$850.0	$850.0
27-Jun-22 17:10	1,801.0	1,801.0	0.000	$300.0	$300.0	1,801.0	1,801.0	0.000	$300.0	$300.0
29-Jun-22 16:30	2,712.8	2,525.4	187.402	$399.2	$399.2	2,712.8	2,525.4	187.402	$399.2	$399.2
28-Jul-22 16:05	1,757.0	1,567.0	190.000	$814.4	$814.4	1,757.0	1,567.0	190.000	$814.4	$814.4

On January 13, 2022 for two intervals, beginning 0625 EPT and 0630 EPT, and on January 31, 2022 for one interval, beginning 0635 EPT, there was no primary reserve shortage in the RTO Reserve Zone and the MAD Subzone. But Table 3-86 shows that the RTO synchronized reserve MCP reached $1,700 per MWh during these three intervals even though the ORDC for synchronized reserves has a cap of $850 per MWh and the RTO primary reserve MCP was zero. The RTO synchronized reserve MCP of $1,700 per MWh was capped at the tariff specified overall cap on synchronized reserves by PJM. However, the price was inconsistent with the RTO synchronized reserve ORDC that has a maximum price of $850 per MWh. Without a simultaneous primary reserve MCP that is greater than zero, the synchronized reserve MCP for the RTO Zone should not exceed $850 per MWh. During these three intervals, PJM's process of implementing shortage pricing for synchronized reserves was inconsistent with the tariff defined ORDC. In the MAD Subzone (Table 3-87), the uncapped MCP exceeded $2,550 per MWh, which is the sum of the RTO synchronized reserve constraint shadow price ($1,700 per MWh) and the MAD synchronized reserve constraint shadow price ($850 per MWh). PJM capped the MAD synchronized reserve MCP at $1,700 per MWh, the tariff defined overall cap for synchronized reserves. With primary reserve MCPs at zero, the uncapped MCP for MAD synchronized reserve should not exceed $1,700 per MWh.

In the first nine months of 2022, there were 11 five minute intervals when the market clearing prices were set by the second step of the ORDC ($300 per MWh) when reserves were short of the extended requirement by 0.00001 MW. This included eight five-minute intervals when RTO synchronized reserves were short by 0.00001 MW and three-five minute intervals when RTO primary reserves were short by 0.00001 MW. These are not legitimate shortages of reserves, but instead a result of software error. When the largest contingency on the system is located in the MAD subzone, both the MAD and the RTO reserve requirements are set by this contingency, and the reserve requirement quantities for MAD and RTO are identical. In the real-time market clearing software, to avoid an issue with inaccurate prices that result from such situations, the software adds a small quantity (0.00001 MW) to the RTO reserve requirement, to differentiate the constraint from the MAD reserve requirement constraint. When the RTO reserve quantities are short by this quantity (0.00001 MW), there is no shortage of reserves compared to the reserve requirement for the RTO zone, since this was an artificially added quantity to resolve modeling issues. The market clearing prices for reserves and the LMPs should not include the penalty factor for the reserve product when the reserves are short by 0.00001 MW. The market clearing prices and LMPs during these 11 intervals are not consistent with the shortage pricing rules in the PJM tariff.

The process of calculating reserve constraint shadow prices and implementing reserve price caps in PJM is not transparent. 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.

Table 3-87 Real-time MAD synchronized reserve shortage intervals: January through September, 2022

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)
13-Jan-22 06:25	1,796.0	1,396.9	399.234	$3,419.7	$1,700.0	1,796.0	1,396.9	399.234	$3,419.7	$1,700.0
13-Jan-22 06:30	1,812.0	1,310.7	501.260	$2,937.2	$1,700.0	1,812.0	1,310.7	501.260	$2,937.2	$1,700.0
16-Jan-22 16:35	1,859.0	1,669.0	190.000	$701.3	$701.3	1,859.0	1,669.0	190.000	$701.3	$701.3
27-Jan-22 06:00	1,763.0	1,573.0	190.000	$311.2	$311.2	1,763.0	1,573.0	190.000	$311.2	$311.2
27-Jan-22 06:10	1,793.0	1,603.0	190.000	$368.5	$368.5	1,793.0	1,603.0	190.000	$368.5	$368.5
30-Jan-22 01:40	1,773.0	1,583.0	190.000	$579.0	$579.0	1,773.0	1,583.0	190.000	$579.0	$579.0
30-Jan-22 01:45	1,786.0	1,595.9	190.000	$676.2	$676.2	1,786.0	1,595.9	190.000	$676.2	$676.2
30-Jan-22 01:50	1,815.0	1,625.0	190.000	$666.9	$666.9	1,815.0	1,625.0	190.000	$666.9	$666.9
30-Jan-22 01:55	1,829.0	1,639.0	190.000	$568.3	$568.3	1,829.0	1,639.0	190.000	$568.3	$568.3
31-Jan-22 06:35	1,690.0	1,248.3	441.679	$2,578.6	$1,700.0	1,690.0	1,248.3	441.679	$2,539.5	$1,700.0
31-Jan-22 06:40	1,692.0	1,566.4	125.611	$646.6	$646.6	1,692.0	1,566.4	125.611	$646.6	$646.6
02-Mar-22 17:25	1,641.0	1,524.9	115.996	$600.0	$600.0	1,641.0	1,524.9	115.996	$600.0	$600.0
02-Mar-22 17:30	1,638.0	1,448.0	190.000	$815.5	$815.5	1,638.0	1,448.0	190.000	$815.5	$815.5
12-Mar-22 10:20	1,825.0	1,708.1	116.856	$600.0	$600.0	1,825.0	1,708.1	116.856	$600.0	$600.0
20-Mar-22 19:40	1,642.0	1,636.2	5.840	$600.0	$600.0	1,642.0	1,636.2	5.840	$600.0	$600.0
13-Apr-22 17:30	1,534.7	1,450.5	84.248	$600.0	$600.0	1,534.7	1,450.5	84.248	$600.0	$600.0
14-Apr-22 09:35	1,533.7	1,459.9	73.782	$600.0	$600.0	1,533.7	1,459.9	73.782	$600.0	$600.0
16-May-22 15:55	1,789.0	1,680.1	108.910	$600.0	$600.0	1,789.0	1,680.1	108.910	$600.0	$600.0
13-Jun-22 15:00	1,766.0	1,580.0	186.017	$2,300.0	$1,700.0	1,766.0	1,580.0	186.017	$2,300.0	$1,700.0
13-Jun-22 15:05	1,765.0	1,758.6	6.466	$1,200.0	$1,200.0	1,765.0	1,758.6	6.466	$1,200.0	$1,200.0
13-Jun-22 16:00	1,766.0	1,707.7	58.206	$2,300.0	$1,700.0	1,766.0	1,707.7	58.206	$2,300.0	$1,700.0
13-Jun-22 16:05	1,764.0	1,649.5	114.499	$2,300.0	$1,700.0	1,764.0	1,649.5	114.499	$2,300.0	$1,700.0
13-Jun-22 16:25	1,768.0	1,726.8	41.734	$2,300.0	$1,700.0	1,768.0	1,726.8	41.734	$2,300.0	$1,700.0
13-Jun-22 16:30	1,770.0	1,727.5	42.408	$2,300.0	$1,700.0	1,770.0	1,727.5	42.408	$2,300.0	$1,700.0
13-Jun-22 16:45	1,770.0	1,679.7	90.362	$2,300.0	$1,700.0	1,770.0	1,679.7	90.362	$2,300.0	$1,700.0
13-Jun-22 17:45	1,765.0	1,739.3	25.792	$2,300.0	$1,700.0	1,765.0	1,739.3	25.792	$2,300.0	$1,700.0
27-Jun-22 17:05	1,792.0	1,602.1	190.000	$1,378.5	$1,378.5	1,792.0	1,602.1	190.000	$1,378.5	$1,378.5
29-Jun-22 16:30	2,712.8	2,525.4	187.402	$699.2	$699.2	2,712.8	2,525.4	187.402	$699.2	$699.2
28-Jul-22 16:05	1,757.0	1,567.0	190.000	$1,114.4	$1,114.4	1,757.0	1,567.0	190.000	$1,114.4	$1,114.4

Table 3-88 Real-time RTO primary reserve shortage intervals: January through September, 2022

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)
31-Jan-22 07:15	2,614.0	2,614.0	0.000	$300.0	$300.0	2,614.0	2,614.0	0.000	$285.7	$285.7
13-Jun-22 14:55	2,551.0	2,541.7	9.351	$300.0	$300.0	2,551.0	2,541.7	9.351	$300.0	$300.0
13-Jun-22 15:00	2,554.0	2,315.9	238.117	$850.0	$850.0	2,554.0	2,315.9	238.117	$850.0	$850.0
13-Jun-22 15:05	2,552.5	2,494.4	58.066	$300.0	$300.0	2,552.5	2,494.4	58.066	$300.0	$300.0
13-Jun-22 15:25	2,551.0	2,551.0	0.000	$300.0	$300.0	2,551.0	2,551.0	0.000	$243.7	$243.7
13-Jun-22 15:30	2,558.5	2,558.5	0.000	$300.0	$300.0	2,558.5	2,558.5	0.000	$288.5	$288.5
13-Jun-22 15:35	2,552.5	2,404.1	148.363	$300.0	$300.0	2,552.5	2,436.2	116.302	$300.0	$300.0
13-Jun-22 15:40	2,557.0	2,367.0	190.000	$593.5	$593.5	2,557.0	2,367.0	190.000	$593.5	$593.5
13-Jun-22 15:45	2,551.0	2,052.6	498.351	$850.0	$850.0	2,551.0	2,052.6	498.351	$850.0	$850.0
13-Jun-22 15:50	2,552.5	2,019.9	532.586	$850.0	$850.0	2,552.5	2,019.9	532.586	$850.0	$850.0
13-Jun-22 15:55	2,554.0	2,030.7	523.308	$850.0	$850.0	2,554.0	2,030.7	523.308	$850.0	$850.0
13-Jun-22 16:00	2,554.0	1,897.7	656.306	$850.0	$850.0	2,554.0	1,897.7	656.306	$850.0	$850.0
13-Jun-22 16:05	2,551.0	1,839.4	711.599	$850.0	$850.0	2,551.0	1,839.4	711.599	$850.0	$850.0
13-Jun-22 16:10	2,555.5	2,011.4	544.098	$850.0	$850.0	2,555.5	2,011.4	544.098	$850.0	$850.0
13-Jun-22 16:15	2,557.0	1,957.9	599.100	$850.0	$850.0	2,557.0	1,957.9	599.100	$850.0	$850.0
13-Jun-22 16:20	2,555.5	2,028.8	526.682	$850.0	$850.0	2,555.5	2,028.8	526.682	$850.0	$850.0
13-Jun-22 16:25	2,557.0	1,916.6	640.834	$850.0	$850.0	2,557.0	1,916.6	640.834	$850.0	$850.0
13-Jun-22 16:30	2,560.0	1,917.5	642.508	$850.0	$850.0	2,560.0	1,917.5	642.508	$850.0	$850.0
13-Jun-22 16:35	2,561.5	1,960.9	600.600	$850.0	$850.0	2,561.5	1,960.9	600.600	$850.0	$850.0
13-Jun-22 16:40	2,561.5	1,997.5	564.040	$850.0	$850.0	2,561.5	1,997.5	564.040	$850.0	$850.0
13-Jun-22 16:45	2,560.0	1,869.6	690.462	$850.0	$850.0	2,560.0	1,869.6	690.462	$850.0	$850.0
13-Jun-22 16:50	2,560.0	1,959.9	600.100	$850.0	$850.0	2,560.0	1,959.9	600.100	$850.0	$850.0
13-Jun-22 16:55	2,560.0	2,352.5	207.543	$850.0	$850.0	2,560.0	2,352.5	207.543	$850.0	$850.0
13-Jun-22 17:00	2,557.0	2,367.0	190.000	$850.0	$850.0	2,557.0	2,367.0	190.000	$850.0	$850.0
13-Jun-22 17:05	2,552.5	2,179.5	373.034	$850.0	$850.0	2,552.5	2,179.5	373.034	$850.0	$850.0
13-Jun-22 17:10	2,552.5	2,474.3	78.214	$300.0	$300.0	2,552.5	2,474.5	78.036	$300.0	$300.0
13-Jun-22 17:15	2,552.5	2,362.5	190.000	$850.0	$850.0	2,552.5	2,362.5	190.000	$445.0	$445.0
13-Jun-22 17:20	2,552.5	2,362.5	190.000	$850.0	$850.0	2,552.5	2,362.5	190.000	$445.0	$445.0
13-Jun-22 17:25	2,549.5	2,359.5	190.000	$816.4	$816.4	2,549.5	2,359.5	190.000	$649.2	$649.2
13-Jun-22 17:30	2,555.5	2,231.7	323.737	$850.0	$850.0	2,555.5	2,231.7	323.737	$850.0	$850.0
13-Jun-22 17:35	2,552.5	2,280.4	272.108	$850.0	$850.0	2,552.5	2,280.4	272.108	$850.0	$850.0
13-Jun-22 17:40	2,554.0	2,342.6	211.454	$850.0	$850.0	2,554.0	2,342.6	211.454	$850.0	$850.0
13-Jun-22 17:45	2,552.5	1,946.1	606.392	$850.0	$850.0	2,552.5	1,946.1	606.392	$850.0	$850.0
13-Jun-22 17:50	2,552.5	2,088.0	464.554	$850.0	$850.0	2,552.5	2,088.0	464.554	$850.0	$850.0
13-Jun-22 17:55	2,552.5	2,468.7	83.837	$300.0	$300.0	2,552.5	2,552.5	0.000	$300.0	$300.0
13-Jun-22 18:00	2,552.5	2,226.7	325.729	$850.0	$850.0	2,552.5	2,226.7	325.729	$850.0	$850.0

Table 3-89 Real-time MAD primary reserve shortage intervals: January through September, 2022

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)
13-Jun-22 14:55	2,551.0	2,541.7	9.4	$600.0	$600.0	2,551.0	2,541.7	9.4	$600.0	$600.0
13-Jun-22 15:00	2,554.0	2,315.9	238.1	$1,700.0	$850.0	2,554.0	2,315.9	238.1	$1,700.0	$850.0
13-Jun-22 15:05	2,552.5	2,494.5	58.1	$600.0	$600.0	2,552.5	2,494.5	58.1	$600.0	$600.0
13-Jun-22 15:35	2,552.5	2,404.1	148.4	$600.0	$600.0	2,552.5	2,436.2	116.3	$600.0	$600.0
13-Jun-22 15:40	2,557.0	2,367.0	190.0	$893.5	$850.0	2,557.0	2,367.0	190.0	$893.5	$850.0
13-Jun-22 15:45	2,551.0	2,052.6	498.4	$1,700.0	$850.0	2,551.0	2,052.6	498.4	$1,700.0	$850.0
13-Jun-22 15:50	2,552.5	2,019.9	532.6	$1,700.0	$850.0	2,552.5	2,019.9	532.6	$1,700.0	$850.0
13-Jun-22 15:55	2,554.0	2,030.8	523.3	$1,700.0	$850.0	2,554.0	2,030.8	523.3	$1,700.0	$850.0
13-Jun-22 16:00	2,554.0	1,897.6	656.3	$1,700.0	$850.0	2,554.0	1,897.6	656.3	$1,700.0	$850.0
13-Jun-22 16:05	2,551.0	1,839.4	711.6	$1,700.0	$850.0	2,551.0	1,839.4	711.6	$1,700.0	$850.0
13-Jun-22 16:10	2,555.5	2,011.4	544.1	$1,700.0	$850.0	2,555.5	2,011.4	544.1	$1,700.0	$850.0
13-Jun-22 16:15	2,557.0	1,957.8	599.1	$1,700.0	$850.0	2,557.0	1,957.8	599.1	$1,700.0	$850.0
13-Jun-22 16:20	2,555.5	2,028.8	526.7	$1,700.0	$850.0	2,555.5	2,028.8	526.7	$1,700.0	$850.0
13-Jun-22 16:25	2,557.0	1,916.7	640.8	$1,700.0	$850.0	2,557.0	1,916.7	640.8	$1,700.0	$850.0
13-Jun-22 16:30	2,560.0	1,917.4	642.5	$1,700.0	$850.0	2,560.0	1,917.4	642.5	$1,700.0	$850.0
13-Jun-22 16:35	2,561.5	1,961.0	600.6	$1,700.0	$850.0	2,561.5	1,961.0	600.6	$1,700.0	$850.0
13-Jun-22 16:40	2,561.5	1,997.4	564.0	$1,700.0	$850.0	2,561.5	1,997.4	564.0	$1,700.0	$850.0
13-Jun-22 16:45	2,560.0	1,869.6	690.5	$1,700.0	$850.0	2,560.0	1,869.6	690.5	$1,700.0	$850.0
13-Jun-22 16:50	2,560.0	1,959.9	600.1	$1,700.0	$850.0	2,560.0	1,959.9	600.1	$1,700.0	$850.0
13-Jun-22 16:55	2,560.0	2,352.5	207.5	$1,700.0	$850.0	2,560.0	2,352.5	207.5	$1,700.0	$850.0
13-Jun-22 17:00	2,557.0	2,367.0	190.0	$1,466.6	$850.0	2,557.0	2,367.0	190.0	$1,466.6	$850.0
13-Jun-22 17:05	2,552.5	2,179.5	373.0	$1,700.0	$850.0	2,552.5	2,179.5	373.0	$1,700.0	$850.0
13-Jun-22 17:10	2,552.5	2,474.4	78.2	$600.0	$600.0	2,552.5	2,474.5	78.0	$600.0	$600.0
13-Jun-22 17:15	2,552.5	2,362.5	190.0	$1,174.3	$850.0	2,552.5	2,362.6	190.0	$745.0	$745.0
13-Jun-22 17:20	2,552.5	2,362.5	190.0	$1,174.3	$850.0	2,552.5	2,362.6	190.0	$745.0	$745.0
13-Jun-22 17:25	2,549.5	2,359.5	190.0	$1,116.4	$850.0	2,549.5	2,359.5	190.0	$949.2	$850.0
13-Jun-22 17:30	2,555.5	2,231.8	323.7	$1,700.0	$850.0	2,555.5	2,231.8	323.7	$1,700.0	$850.0
13-Jun-22 17:35	2,552.5	2,280.4	272.1	$1,700.0	$850.0	2,552.5	2,280.4	272.1	$1,700.0	$850.0
13-Jun-22 17:40	2,554.0	2,342.6	211.5	$1,700.0	$850.0	2,554.0	2,342.6	211.5	$1,700.0	$850.0
13-Jun-22 17:45	2,552.5	1,946.2	606.4	$1,700.0	$850.0	2,552.5	1,946.2	606.4	$1,700.0	$850.0
13-Jun-22 17:50	2,552.5	2,088.0	464.6	$1,700.0	$850.0	2,552.5	2,088.0	464.6	$1,700.0	$850.0
13-Jun-22 17:55	2,552.5	2,468.6	83.8	$600.0	$600.0	2,552.5	2,552.4	0.0	$509.9	$509.9
13-Jun-22 18:00	2,552.5	2,226.8	325.7	$1,700.0	$850.0	2,552.5	2,226.8	325.7	$1,700.0	$850.0

The PJM tariff caps the MCP for primary reserves at one times the nonsynchronized reserve penalty factor for each zone or subzone, and caps the MCP for synchronized reserves at the sum of the penalty factor for synchronized reserve and the penalty factor for nonsynchronized reserve, but the PJM tariff does not explicitly specify a cap on the system marginal price.[135]

135 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

System Marginal Price Cap

In the PJM real-time market, the SMP is capped at $3,750 per MWh. This cap is the result of the Energy Offer Cap ($2,000 per MWh under defined conditions), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement states that only two, of the four, reserve penalty factors may be applied.

If the SMP would otherwise exceed $3,750 per MWh, PJM solves the SCED optimization by progressively relaxing reserve requirement constraints until the SMP falls below the cap. For instance, if the original SMP is above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization is still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization is still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Since 2018, the SMP has been capped in 95 SCED solutions, of which four SCED solutions were approved and used in the LPC to set the five minute LMPs in the PJM real-time market.

Table 3-90 shows the shadow price, MCP and SMP for all reserve constraints for SCED cases that were solved using PJM's SMP capping logic and set the prices in the PJM real-time market. The shadow price of a reserve requirement constraint is the marginal cost of satisfying an increase in the reserve requirement. The shadow price equals the penalty factor of the reserve requirement constraint if the total cleared reserves are below the requirement.

Table 3-91 shows the components of SMP for the five minute intervals that used SMP capping logic since 2018. The SMP is the marginal cost of satisfying an increase in load at the load weighted reference bus. That marginal cost includes the marginal cost of generation, the marginal cost of congestion and the marginal cost of reserves. By definition, all of these marginal costs are included in the marginal energy component of LMP at the load weighted reference bus, which is referred to as the system marginal price (SMP). The marginal cost of generation is the incremental offer price of the marginal generation resource adjusted for the marginal cost of losses. The marginal cost of congestion reflects the marginal cost of the unit required to meet the load if there are transmission constraints, including transmission penalty factors when relevant. If the marginal unit is also providing reserves, the marginal cost of reserves reflects the marginal cost incurred to meet the reserve requirement.

For example, the SMP for the five minute interval beginning at 10:10 on March 17, 2021 was $3,653.98 per MWh. The MAD primary reserve constraint was disabled for this interval. Of the $3,653.98 per MWh, the marginal unit's incremental energy cost after accounting for the marginal cost of losses was $17.85 per MWh, the congestion cost was $1,546.98 per MWh and the reserve opportunity cost was $2,086.15 per MWh. The remaining $3.00 is rounding error.[136] The SMP, without the use of the capping logic, would have been at least $3,965.08 per MWh.[137]

The contribution of the transmission penalty factor of a violated transmission constraint to the SMP depends on the location of the marginal units relative to the location of the load weighted reference bus. If the marginal unit is located such that an incremental increase in the load at the load weighted reference bus results in increased flow on the violated transmission constraint, the SMP reflects the positive contribution of the transmission penalty factor. The marginal congestion component, $1,546.98, for the five minute interval beginning at 10:10 on March 17, 2021, includes the contribution of transmission constraint penalty factors of two violated transmission constraints.

136 The final SMP does not precisely match the sum of components due to rounded network parameters such as distribution factors and loss penalty factors used for deriving the components of the SMP. This difference is shown as rounding error.

137 The original SMP shown in the table represents the lower bound of the uncapped SMP. PJM does not report the segment of the disabled reserve constraint. To derive the original SMP, the lowest priced segment that results in the SMP exceeding the cap was used.

Table 3-90 Five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through September 2022

Five Minute Interval	Reserve Constraint	Disabled	Shadow Price ($/MWh)	MCP ($/MWh)	SMP ($/MWh)
October 01, 2019 15:00:00	MAD Primary Reserve	No	$0.00	$300.00	$3,651.02
October 01, 2019 15:00:00	MAD Synchronized Reserve	Yes	$0.00	$1,150.00	$3,651.02
October 01, 2019 15:00:00	RTO Synchronized Reserve	No	$850.00	$1,150.00	$3,651.02
October 01, 2019 15:00:00	RTO Primary Reserve	No	$300.00	$300.00	$3,651.02
November 13, 2020 18:00:00	MAD Primary Reserve	Yes	$0.00	$850.00	$3,166.28
November 13, 2020 18:00:00	MAD Synchronized Reserve	No	$850.00	$2,550.00	$3,166.28
November 13, 2020 18:00:00	RTO Primary Reserve	No	$850.00	$850.00	$3,166.28
November 13, 2020 18:00:00	RTO Synchronized Reserve	No	$850.00	$1,700.00	$3,166.28
March 02, 2021 06:30:00	MAD Synchronized Reserve	Yes	$0.00	$2,782.22	$2,994.68
March 02, 2021 06:30:00	MAD Primary Reserve	No	$149.36	$999.36	$2,994.68
March 02, 2021 06:30:00	RTO Primary Reserve	No	$850.00	$850.00	$2,994.68
March 02, 2021 06:30:00	RTO Synchronized Reserve	No	$1,782.86	$2,632.86	$2,994.68
March 17, 2021 10:10:00	MAD Synchronized Reserve	No	$850.00	$2,000.00	$3,653.98
March 17, 2021 10:10:00	RTO Primary Reserve	No	$300.00	$300.00	$3,653.98
March 17, 2021 10:10:00	RTO Synchronized Reserve	No	$850.00	$1,150.00	$3,653.98
March 17, 2021 10:10:00	MAD Primary Reserve	Yes	$0.00	$300.00	$3,653.98

Table 3-91 Components of SMP for five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through September 2022

		Components of Final SMP				
Five Minute Interval	Lower Bound of Original SMP	Final SMP	Marginal Cost of Generation	Marginal Cost of Congestion	Marginal Cost of Reserves	Rounding Error
October 01, 2019 15:00:00	$3,950.36	$3,651.02	$33.88	$2,436.47	$1,173.81	$6.87
November 13, 2020 18:00:00	$4,049.76	$3,166.28	$520.20	$0.00	$2,645.22	$0.86
March 02, 2021 06:30:00	$3,891.21	$2,994.68	$30.51	$181.10	$2,780.81	$2.26
March 17, 2021 10:10:00	$3,965.08	$3,653.98	$17.85	$1,546.98	$2,086.15	$3.00

The MMU recommends that PJM cease the practice of capping the system marginal price in the RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[138] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. PJM should address these complexities through generator modeling improvements. PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

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

PJM deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the real-time energy output of generators adjusted with scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

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

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is between 1000 and 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[139]

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first nine months of 2022, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market during the first nine months of 2022 was unconcentrated on average (Table 3-92).[140] The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

Table 3-92 Real-time hourly aggregate energy market HHI: January through September, 2021 and 2022

By offering supplier	Hourly Market HHI (Jan - Sep, 2021)	Hourly Market HHI (Jan - Sep, 2022)
Average	743	690
Minimum	530	554
Maximum	1114	1012
Highest market share (One hour)	27%	26%
Average of the highest hourly market share	19%	18%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-93 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2021 and 2022. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking

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

140 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the supplier that is responsible for offering the unit in the energy market.

segment was highly concentrated.[141] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-93 Real-time hourly energy market HHI by generation segment: January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	621	786	1121	587	721	1032
Intermediate	574	1420	9838	690	1634	9378
Peak	711	6022	10000	817	6687	10000

Figure 3-54 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2022.[142]

Figure 3-54 Real-time ICAP distribution by fuel and segment: January through September, 2022[143]

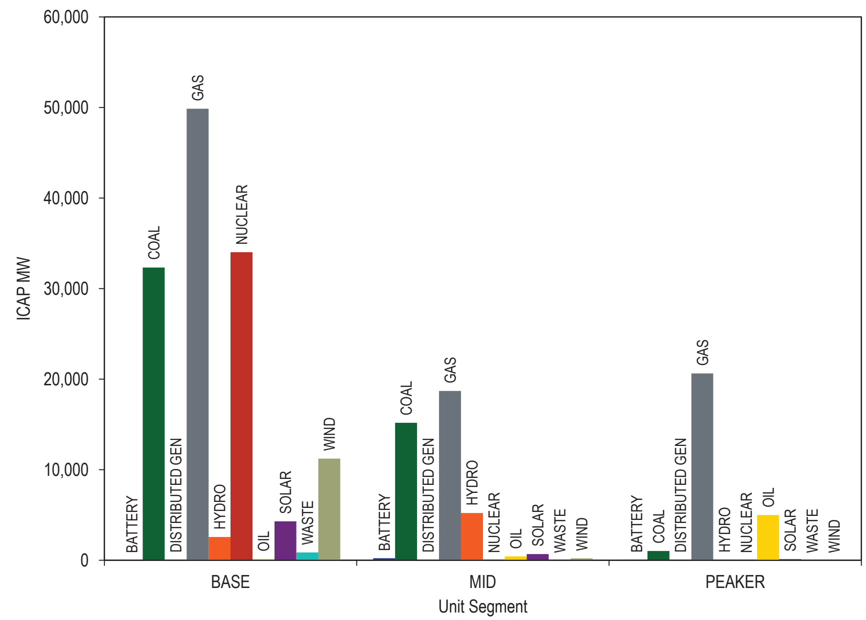


Figure 3-55 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking during the first nine months from 2014 through 2022. Figure 3-55 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased during the first nine months from 2014 through 2022, and the total ICAP of gas fired units in PJM classified as baseload generally increased during the first nine months from 2014 through 2022. In the first nine months of 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time. The ICAP of coal fired units classified as baseload increased in 2021 and decreased in 2022.

141 A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

142 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

143 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-55 Real-time annual gas and coal unit segment classification: January through September, 2013 through 2022

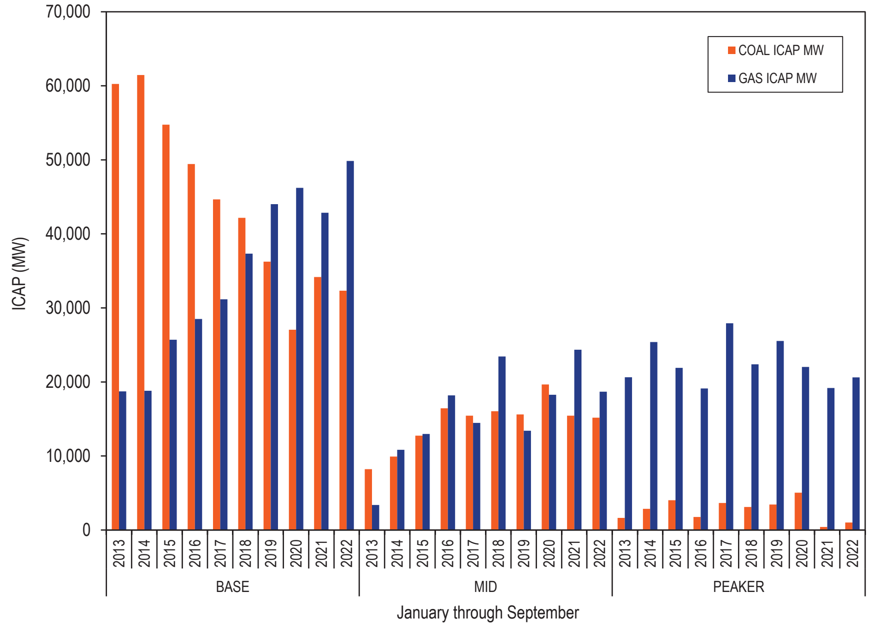
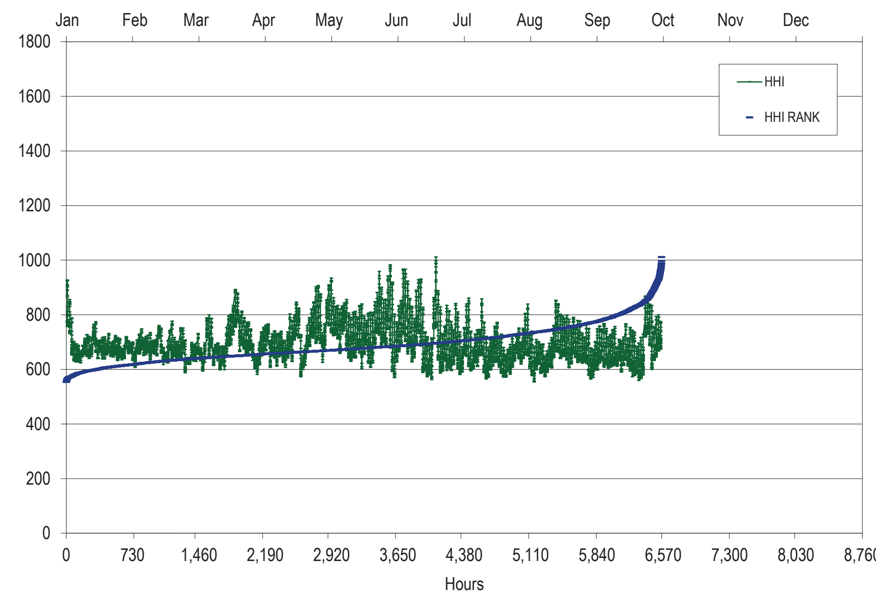


Figure 3-56 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2022.

Figure 3-56 Real-time hourly aggregate energy market HHI: January through September, 2022



Market Based Rates

Participation in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[144] FERC reviews the market based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM

144 See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'gg*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom.* Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011).

market rules. With Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[145]

The rules specify a separate filing schedule for transmission owning utilities and nontransmission owning utilities. The rules define a study period for market power analyses including four complete seasons, not the calendar year. A study runs from December of one year through November of the following year (i.e., the period includes one complete winter season rather than splitting winter as a calendar year approach would).

The most recent triennial review filings for nontransmission owning utilities in PJM were due on June 20, 2020. The applicable study period for the June 20, 2020 triennial filing, ran from December 1, 2017, to November 30, 2018. Triennial review filings for transmission owners in PJM will be due in December 2022. The applicable study period for the December 2020 filing ran from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. The MMU has found that the capacity market is not competitive because the default Market Seller Offer Cap (MSOC) is inflated.[146] With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020 triennial review filings by generating unit owners in PJM and recommended that conditions limiting sellers to cost-based energy offers and a revised capacity market seller offer cap be required until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[147] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[148] [149]

145 *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 No. 861").
146 See Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, (February 21, 2019), which can be accessed at <https://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf>.
147 See, e.g., Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 (August 28, 2020).
148 See 175 FERC ¶ 61,231 (2021).
149 See 174 FERC ¶ 61,212 (2021).

Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[150]

FERC applies tests set forth in the 1996 Merger Policy Statement.[151] [152] The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.[153]

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments including such analyses.[154] The MMU has proposed

150 18 U.S.C. § 824b.
151 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).
152 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.
153 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)
154 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

that FERC adopt this approach when evaluating mergers in PJM.[155] FERC has considered the MMU's analysis in reviewing mergers but continues to apply a definition of markets based on an outdated and static definition of relevant markets in PJM.[156]

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-94 shows transactions that involved entire resources that were completed in the first nine months of 2022, as reported to the Commission. Table 3-95 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2022, as reported to the Commission.[157]

Table 3-94 Completed transfers of entire resources: January through September, 2022

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Rolling Hills Generating, LLC	Arclight Capital Partners	LSP Development	September 16, 2022	EC22-76
Crete Energy Venture, LLC, Lincoln Generating Facility LLC	Eastern LC, LLC	Earthrise Energy, PBC	September 6, 2022	EC22-75
Cardinal Station Unit 1	AEP Generation Resources Inc.	Buckeye Power, Inc	August 1, 2022	EC22-50
INGENCO Wholesale Power, LLC	Collegiate Clean Energy LLC	Archaea Infrastructure LLC	July 1, 2022	EC22-66
Big Savage, Highland North, Patton Wind	BlackRock, Inc.	Vitol Inc.	June 24, 2022	EC22-56
Energy Center Dover	DCO Energy	Groupe BPCE	May 26, 2022	EC22-37
Glatfelter Cogen	Lindsay Goldberg	HIG Capital	May 25, 2022	EC22-49
Energy Center Paxton	Clearway Energy Inc	KKR & Co. Inc.	May 1, 2022	EC22-16
PSEG Fossil Portfolio	PSEG	Arclight Capital Partners	February 18, 2022	EC21-128
Exelon Generation	Exelon Corp	Constellation Energy Generation	February 1, 2022	EC21-57

Table 3-95 Completed transfers of partial ownership of resources: January through September, 2022

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Black Rock Wind Force LLC (50%)	Clearway Energy Group	TotalEnergies Renewables USA, LLC	September 12, 2022	EC22-84
Chambers Cogen (40%)	I Squared Capital Advisors LLC	Starwood Energy Group	March 21, 2022	EC22-25
CPV Fairview (25%)	Apollo Global Management	DL Energy Co	March 14, 2022	EC22-31

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[158] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of structural mitigation in the form of asset divestiture requirements.

Aggregate Market Pivotal Supplier Results

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

155 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).
156 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc.*, Edison Mission Energy, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).
157 The transaction completion date is based on the notices of consummation submitted to the Commission.
158 See 138 FERC ¶ 61,167 at P 19 (2012). The Maryland PSC accepted without condition or modification the settlement between Constellation and the MMU at the February 1, 2022, hearing in Case No. 9271. See *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Order Approving 2021 Settlement Agreement and Denying Request to Require Exelon to Remain In PJM, Case No. 9271 (February 22, 2022). By its terms, the settlement became effective on February 1, 2022.

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

The existing market power mitigation measures do not address aggregate market power.[159] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

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

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

Figure 3-57 shows the number of days in 2021 and the first nine months of 2022 with one aggregate pivotal supplier, two aggregate jointly pivotal suppliers, and three aggregate jointly pivotal suppliers for the day-ahead energy market. Multiple suppliers were singly pivotal on the summer peak days of 2021 and 2022. One supplier was singly pivotal on February 15, 2021, on July 6, 2021, and three days in August 2021, and on June 15 and 16, 2022. Two suppliers were jointly pivotal on 116 days in 2021 and on 77 days in the first nine months of 2022. Three suppliers were jointly pivotal on 286 days in 2021 and 215 days in the nine months of 2022, despite average HHIs at persistently unconcentrated levels. In 2021 and 2022, the highest levels of aggregate market power occurred in the third quarter, PJM's summer peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in February 2021 and January 2022.

Figure 3-57 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

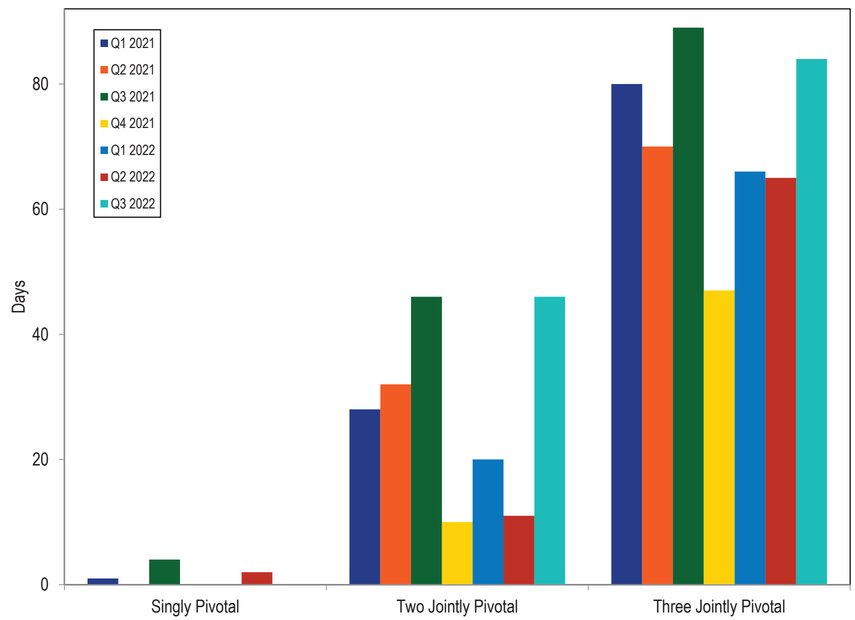


Table 3-96 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first nine months of 2022. All of the top 10 suppliers were one of three pivotal suppliers on at least 112 days in the first nine months of 2022 (41.2 percent of the days).

Table 3-96 Day-ahead market pivotal supplier frequency: January through September, 2022

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	2	0.7%	72	26.4%	207	75.8%
2	1	0.4%	71	26.0%	209	76.6%
3	0	0.0%	57	20.9%	208	76.2%
4	0	0.0%	54	19.8%	212	77.7%
5	0	0.0%	44	16.1%	169	61.9%
6	0	0.0%	18	6.6%	136	49.8%
7	0	0.0%	14	5.1%	137	50.2%
8	0	0.0%	14	5.1%	112	41.0%
9	0	0.0%	8	2.9%	118	43.2%
10	0	0.0%	6	2.2%	114	41.8%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[160] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based, also called price-based, offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2022, the 500 kV system, 11 zones, and MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-97).[161] Table 3-97 shows that the 500 kV system, five zones and MISO experienced congestion resulting from one or more constraints binding for 75 or more

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

161 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the control zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

hours or resulting from a binding interface constraint in the first nine months of every year from 2013 through 2022. Two control zones did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months of any year from 2013 through 2022.[162]

Table 3-97 Congestion hours resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2013 through 2022

	(Jan - Sep)									
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
500 kV System	1,286	2,052	836	526	958	782	2,817	2,078	1,424	1,011
ACEC	0	0	96	413	0	94	97	0	0	0
AEP	897	1,452	1,656	441	469	1,017	381	887	915	311
APS	0	170	356	157	136	184	0	319	0	82
ATSI	34	325	307	1	135	814	2	0	0	78
BGE	338	1,668	2,925	4,227	1,297	2,144	533	2,040	1,176	495
COMED	1,264	1,227	907	2,588	913	675	78	856	631	863
DAY	0	0	0	0	0	0	0	0	181	0
DOM	474	77	1,008	553	80	136	91	780	441	1,455
DPL	370	338	731	1,991	326	398	0	0	144	0
DUKE	0	0	0	0	0	75	0	0	176	0
DUQ	0	223	368	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	184	0	0	0	0
EXT	0	0	0	0	778	0	0	0	0	0
JCPLC	0	0	79	0	94	0	0	0	0	0
MEC	0	0	111	0	0	920	278	730	286	771
MISO	3,956	4,559	3,455	2,983	3,797	3,048	3,035	2,453	2,104	6,015
NYISO	167	128	173	730	332	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	0	1,997	1,287	169	1,541	1,114	1,013	1,950	328	1,522
PECO	130	791	721	657	1,312	537	224	284	480	2,134
PEPCO	100	41	0	0	0	0	0	0	0	0
PPL	210	148	114	242	563	0	748	460	722	1,582
PSEG	943	1,064	1,577	170	160	211	164	0	682	330
REC	0	0	0	0	0	0	0	0	0	0

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-98 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the transfer interface constraints in the PJM Day-Ahead Energy Market.

Table 3-98 Day-ahead three pivotal supplier test details for interface constraints: January through September, 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005	Peak	223	459	23	0	23
	Off Peak	298	1,349	36	34	2
AEP - DOM	Peak	542	521	19	2	16
	Off Peak	558	359	15	1	14
AP South	Peak	470	708	25	8	17
	Off Peak	575	1,342	27	10	17
BC Pepco	Peak	NA	NA	NA	NA	NA
	Off Peak	646	1,061	19	0	19
Bedington - Black Oak	Peak	88	282	25	19	5
	Off Peak	160	287	25	14	11
PA Central	Peak	170	226	11	1	10
	Off Peak	160	224	9	1	8
Western	Peak	913	2,636	36	29	8
	Off Peak	578	1,234	29	12	17

Table 3-99 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for nine out of the 10 constraints that were binding for the most hours in the PJM Day-Ahead Energy Market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day after the initial unit commitment run. The set of constraints that are binding in the unit commitment run, for which the TPS test is applied, is not necessarily the same as the set of constraints that bind in the final day-ahead energy market solution. This is because PJM's day-ahead market is solved in three stages, and the initial set of constraints is from the Resource Scheduling and Commitment (unit commitment) stage whereas the final set of binding constraints is from the Scheduling Pricing and Dispatch (unit dispatch) stage.[163] The PJM approach fails to apply the TPS test to market sellers that provide relief to constraints

162 The constraint data in the first nine months of 2022 is based on the dispatch run.

163 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6 Rev. 119 (March 23, 2022).

in the final dispatch solution, and therefore fails to mitigate such sellers for market power.

Table 3-99 shows that one of the top ten binding constraints in the day-ahead energy market was not tested for local market power during the first nine months of 2022. The MMU recommends that PJM review the process for 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.

Table 3-99 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through September, 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	350	411	27	10	17
	Off Peak	217	335	24	11	13
Prest - Tibb	Peak	22	36	6	0	6
	Off Peak	19	27	5	0	4
Cumberland - Juniata	Peak	139	81	11	0	10
	Off Peak	88	56	7	0	7
Mountain	Peak	0	0	0	0	0
	Off Peak	0	0	0	0	0
Lenox - North Meshoppen	Peak	72	45	9	1	8
	Off Peak	71	34	7	1	6
Easton - Emuni	Peak	16	7	1	0	1
	Off Peak	7	5	2	0	2
Haumesser Road - Steward	Peak	108	83	5	0	5
	Off Peak	103	57	4	0	4
Boonetown - South Reading	Peak	167	120	7	0	7
	Off Peak	96	100	6	0	6
Shadeland - Lafayette South	Peak	69	73	11	0	11
	Off Peak	73	81	11	1	10
Greys Point - Harmony Village	Peak	433	51	4	0	4
	Off Peak	603	58	5	0	5

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first nine months of 2022.[164] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[165] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-100 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints in the PJM Real-Time Energy Market. Table 3-101 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-100 and Table 3-101 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

164 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

165 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

Table 3-100 Real-time three pivotal supplier test details for interface constraints: January through September, 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	364	440	14	3	10
	Off Peak	402	391	14	2	12
AEP - DOM	Peak	293	193	7	0	7
	Off Peak	391	303	9	0	9
AP South	Peak	596	743	14	2	12
	Off Peak	652	656	13	2	11
Bedington - Black Oak	Peak	184	174	12	2	10
	Off Peak	175	154	11	1	10
Eastern	Peak	472	621	15	4	11
	Off Peak	548	602	14	1	13
PA Central	Peak	219	505	8	1	7
	Off Peak	161	571	7	1	6
Western	Peak	856	580	14	0	14
	Off Peak	654	884	12	4	8

Table 3-101 Real-time three pivotal supplier test details for top 10 congested constraints: January through September, 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	364	440	14	3	10
	Off Peak	402	391	14	2	12
AEP - DOM	Peak	293	193	7	0	7
	Off Peak	391	303	9	0	9
AP South	Peak	596	743	14	2	12
	Off Peak	652	656	13	2	11
Bedington - Black Oak	Peak	184	174	12	2	10
	Off Peak	175	154	11	1	10
Eastern	Peak	472	621	15	4	11
	Off Peak	548	602	14	1	13
PA Central	Peak	219	505	8	1	7
	Off Peak	161	571	7	1	6
Western	Peak	856	580	14	0	14
	Off Peak	654	884	12	4	8

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[166] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-102 shows that 1.3 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-102 shows that 11.1 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

166 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

Table 3-102 Day-ahead units committed on price-based offers that cleared real-time: January through September, 2021 and 2022

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year (Jan - Sep)	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2021	18,076	2,049,312	149,323	0.9%	7.2%
2022	25,111	1,948,936	219,501	1.3%	11.1%

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.

Table 3-103 and Table 3-104 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-103 Summary of real-time three pivotal supplier tests applied for interface constraints: January through September, 2022

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	1,022	1,020	100%	16	2%	2%
	Off Peak	1,265	1,265	100%	21	2%	2%
AEP - DOM	Peak	891	890	100%	25	3%	3%
	Off Peak	1,114	1,113	100%	26	2%	2%
AP South	Peak	3,524	3,523	100%	69	2%	2%
	Off Peak	4,572	4,563	100%	47	1%	1%
Bedington - Black Oak	Peak	2,496	2,486	100%	36	1%	1%
	Off Peak	6,665	6,640	100%	89	1%	1%
Eastern	Peak	1,075	1,060	99%	56	5%	5%
	Off Peak	871	857	98%	21	2%	2%
PA Central	Peak	771	663	86%	0	0%	0%
	Off Peak	556	509	92%	8	1%	2%
Western	Peak	228	228	100%	3	1%	1%
	Off Peak	85	85	100%	0	0%	0%

Table 3-104 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through September, 2022

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Nottingham	Peak	49,401	48,453	98%	552	1%	1%
	Off Peak	30,509	29,847	98%	293	1%	1%
Prest - Tibb	Peak	4,473	205	5%	0	0%	0%
	Off Peak	8,734	147	2%	0	0%	0%
Lenox - North Meshoppen	Peak	17,792	9,560	54%	5	0%	0%
	Off Peak	11,254	4,588	41%	11	0%	0%
Shadeland - Lafayette South	Peak	9,746	8,750	90%	0	0%	0%
	Off Peak	14,946	13,357	89%	0	0%	0%
Boonetown - South Reading	Peak	11,203	4,429	40%	26	0%	1%
	Off Peak	2,597	702	27%	3	0%	0%
Greys Point - Harmony Village	Peak	8,887	8,035	90%	30	0%	0%
	Off Peak	13,207	12,392	94%	53	0%	0%
Lackawanna	Peak	3,147	2,014	64%	4	0%	0%
	Off Peak	2,431	1,430	59%	0	0%	0%
Chicago Ave - Praxair	Peak	4,241	1,583	37%	2	0%	0%
	Off Peak	7,215	3,872	54%	0	0%	0%
Northwest Tap - Purdue	Peak	4,784	1,149	24%	0	0%	0%
	Off Peak	7,673	2,380	31%	0	0%	0%
Cumberland - Juniata	Peak	9,841	5,247	53%	42	0%	1%
	Off Peak	4,109	1,738	42%	26	1%	1%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market. There is no tariff or manual language that defines the PJM process for evaluating units for multi-day commitments in the day-ahead energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. Only under the current approach, where operating parameters are tied to the cost parameters (startup cost, no load cost, and incremental energy offer), is this is consistent with the day-ahead energy market objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period. True least system production cost can be achieved using a approach in which operating parameters and offer parameters are independently evaluated. In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[167]

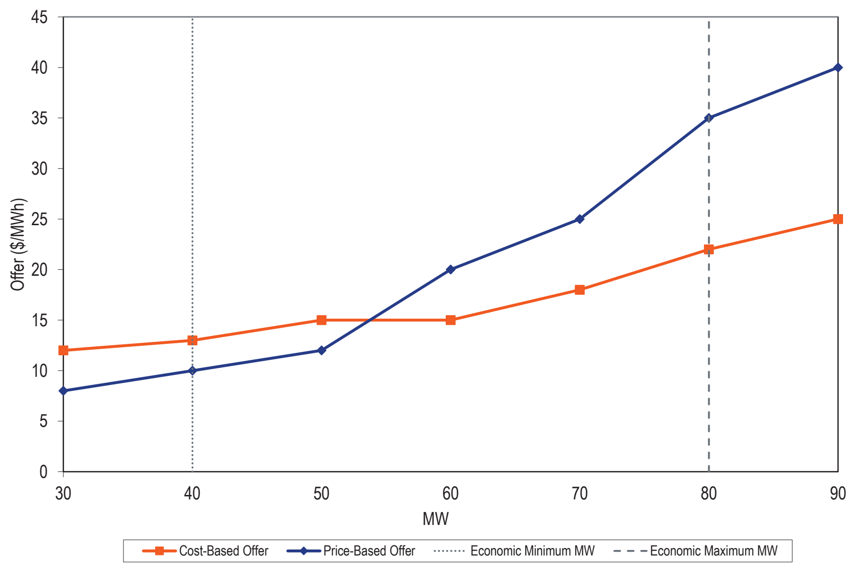
$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

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

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

Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-58 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-58 Offers with varying markups at different MW output levels



167 See OA Schedule 1 § 6.4.1(g).

Table 3-105 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets in the first nine months of 2022. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Table 3-105 Units offered with crossing curves: January through September, 2022

	Day-Ahead			Real-Time		
2022	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	80,695	852,120	9.5%	69,275	799,250	8.7%
Feb	71,587	778,104	9.2%	60,587	713,491	8.5%
Mar	81,695	873,766	9.3%	62,118	738,675	8.4%
Apr	86,781	848,640	10.2%	64,661	682,293	9.5%
May	102,572	875,112	11.7%	78,010	750,802	10.4%
Jun	98,680	832,128	11.9%	82,437	770,067	10.7%
Jul	115,403	858,624	13.4%	102,174	814,863	12.5%
Aug	120,562	857,832	14.1%	104,894	810,338	12.9%
Sep	113,028	827,616	13.7%	97,403	743,300	13.1%
Total	871,003	7,603,942	11.5%	721,559	6,823,079	10.6%

Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-106 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price based offer.

Table 3-106 Units offered with lower minimum run time on price compared to cost and with positive markup: January through September, 2022

	Day-Ahead			Real-Time		
2022	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	5,821	852,120	0.7%	4,948	799,250	0.6%
Feb	4,838	778,104	0.6%	4,158	713,491	0.6%
Mar	7,678	873,766	0.9%	6,523	738,675	0.9%
Apr	8,662	848,640	1.0%	7,171	682,293	1.1%
May	10,132	875,112	1.2%	9,449	750,802	1.3%
Jun	9,897	832,128	1.2%	9,599	770,067	1.2%
Jul	10,656	858,624	1.2%	10,578	814,863	1.3%
Aug	11,416	857,832	1.3%	11,337	810,338	1.4%
Sep	10,680	827,616	1.3%	9,117	743,300	1.2%
Total	79,780	7,603,942	1.0%	72,880	6,823,079	1.1%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-59 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-59 Offers with a positive markup but different economic minimum MW

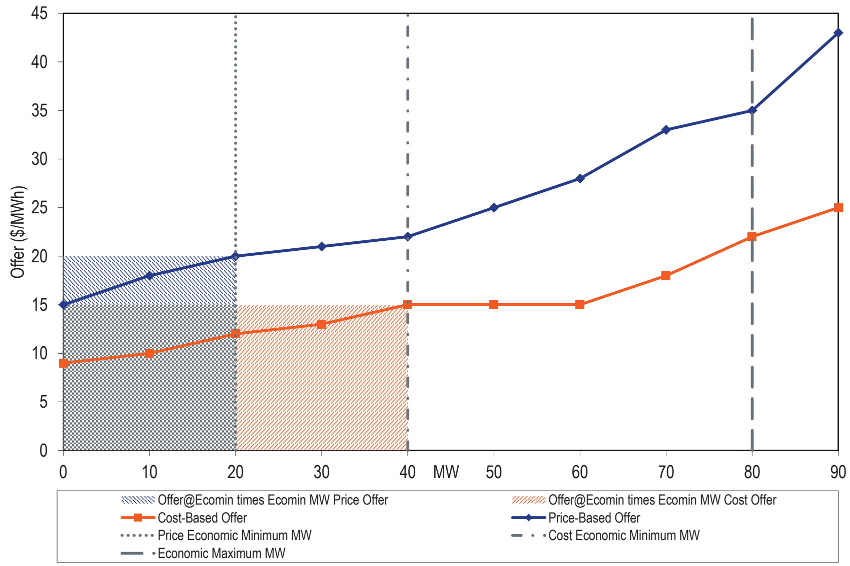


Table 3-107 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-107 Units offered with lower economic minimum MW on price compared to cost and with positive markup: January through September, 2022

	Day-Ahead			Real-Time		
2022	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	0	852,120	0.0%	0	799,250	0.0%
Feb	0	778,104	0.0%	0	713,491	0.0%
Mar	0	873,766	0.0%	0	738,675	0.0%
Apr	0	848,640	0.0%	0	682,293	0.0%
May	0	875,112	0.0%	0	750,802	0.0%
Jun	336	832,128	0.0%	312	770,067	0.0%
Jul	264	858,624	0.0%	264	814,863	0.0%
Aug	336	857,832	0.0%	333	810,338	0.0%
Sep	216	827,616	0.0%	168	743,300	0.0%
Total	1,152	7,603,942	0.0%	1,077	6,823,079	0.0%

In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-60 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup. Table 3-108 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and contains a negative markup. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first nine months of 2022.

Figure 3-60 Dual fuel unit offers

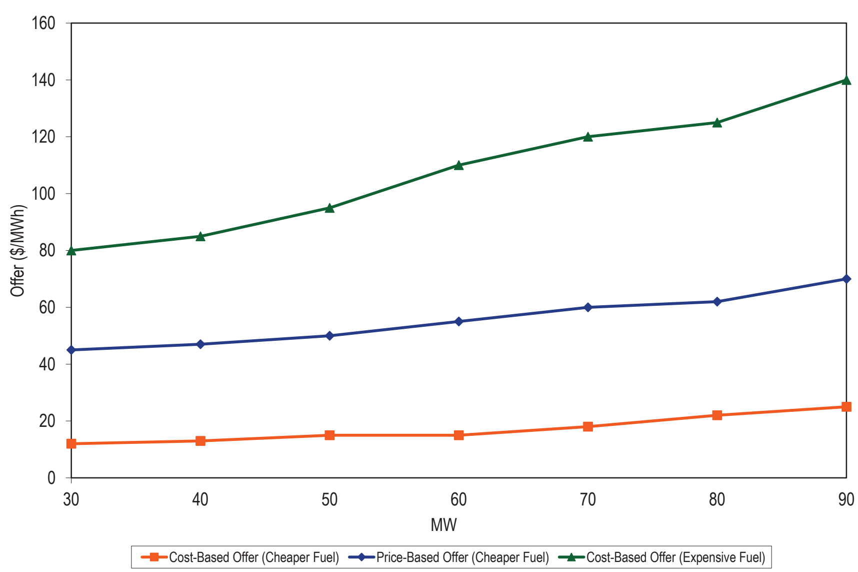


Table 3-108 Dual fuel unit offers with negative markup but different fuel: January through September, 2022

	Day-Ahead			Real-Time		
2021	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	6,496	198,768	3.3%	6,496	191,950	3.4%
Feb	6,904	185,328	3.7%	6,904	172,135	4.0%
Mar	6,099	207,881	2.9%	6,099	168,266	3.6%
Apr	3,998	205,968	1.9%	3,998	167,623	2.4%
May	9,494	205,368	4.6%	9,494	184,625	5.1%
Jun	11,758	193,320	6.1%	11,758	182,862	6.4%
Jul	8,073	200,568	4.0%	8,073	195,537	4.1%
Aug	6,710	199,320	3.4%	6,710	192,313	3.5%
Sep	5,865	188,256	3.1%	5,865	173,195	3.4%
Total	65,397	1,784,777	3.7%	65,397	1,628,506	4.0%

These issues can be solved by simple rule changes.[168] 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. This means that the cost-based and price-based offer curves never cross.[169]

Levels of offer capping have historically been low in PJM, as shown in Table 3-110. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[170] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-109 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[171] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update.

Table 3-109 Offer capping statistics – energy only: January through September, 2017 to 2022

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.3%	0.1%	0.0%	0.1%
2018	1.0%	0.5%	0.1%	0.1%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.3%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.3%	1.1%	1.4%	1.0%

168 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

169 See related recommendations about mitigation of operating parameters and financial offer parameters.

170 See OA Schedule 1 § 6.4.1.

171 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-110 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loop interfaces, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-111. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-109. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-111.

Table 3-110 Offer capping statistics for energy and reliability: January through September, 2017 to 2022

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.4%	0.4%	0.1%	0.3%
2018	1.2%	0.8%	0.2%	0.4%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.5%	1.4%	1.5%	1.1%

Table 3-111 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. 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. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-111 Offer capping statistics for reliability: January through September, 2017 to 2022

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.10%	0.30%	0.10%	0.20%
2018	0.14%	0.29%	0.12%	0.23%
2019	0.01%	0.02%	0.01%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.02%	0.04%	0.02%	0.02%
2022	0.15%	0.27%	0.06%	0.12%

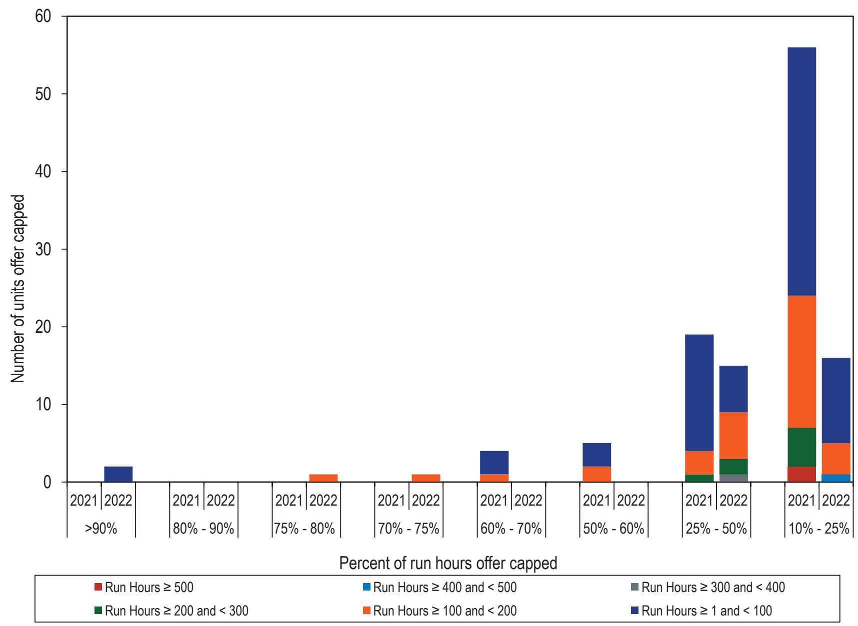
Table 3-112 presents data on the frequency with which units were offer capped in the first nine months of 2021 and 2022 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-112 shows that two units were offer capped for 90 percent or more of their run hours in the first nine months of 2022 compared to zero units in the first nine months of 2021.

Table 3-112 Real-time offer capped unit statistics: January through September, 2021 and 2022

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Sep	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2021	0	0	0	0	0	0
	2022	0	0	0	0	0	2
80% and < 90%	2021	0	0	0	0	0	0
	2022	0	0	0	0	0	0
75% and < 80%	2021	0	0	0	0	0	0
	2022	0	0	0	0	1	0
70% and < 75%	2021	0	0	0	0	0	0
	2022	0	0	0	0	1	0
60% and < 70%	2021	0	0	0	0	1	3
	2022	0	0	0	0	0	0
50% and < 60%	2021	0	0	0	0	2	3
	2022	0	0	0	0	0	0
25% and < 50%	2021	0	0	0	1	3	15
	2022	0	0	1	2	6	6
10% and < 25%	2021	2	0	0	5	17	32
	2022	0	1	0	0	4	11

Figure 3-61 shows the frequency with which units were offer capped in the first nine months of 2021 and 2022 for failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons.

Figure 3-61 Real-time offer capped unit statistics: January through September, 2021 and 2022



Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[172] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-113 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-114 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[173] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

172 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

173 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[174]

In the first nine months of 2022, the average dollar markups of units with offer prices less than $10 was negative (-$4.20 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$5.08 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2022, 4.1 percent had offer prices above $150 per MWh. Among the units that were marginal in the first nine months of 2021, 1.4 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2022 was more than $900, and the highest markup in the first nine months of 2021 was more than $400.

174 See PJM. "Manual 15: Cost Development Guidelines," Rev. 39 (Jan. 18, 2022).

Table 3-113 Real-time average marginal unit markup index (By offer price category unadjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.14	($5.26)	6.2%	4.27	($4.20)	13.5%
$10 to $15	(0.07)	($1.26)	5.0%	(0.18)	($5.08)	0.5%
$15 to $20	(0.04)	($0.94)	21.4%	(0.13)	($3.10)	1.2%
$20 to $25	(0.03)	($0.87)	23.2%	(0.03)	($1.64)	2.1%
$25 to $50	0.01	($0.34)	37.1%	0.01	($0.21)	41.6%
$50 to $75	0.15	$7.79	4.3%	0.02	$0.65	21.8%
$75 to $100	0.26	$21.55	0.8%	0.04	$1.94	9.4%
$100 to $125	0.24	$26.21	0.4%	0.09	$9.09	4.2%
$125 to $150	0.33	$43.81	0.2%	0.14	$18.85	1.6%
>= $150	0.11	$24.28	1.4%	0.07	$16.21	4.1%
All Offers	(0.00)	$0.11	100.0%	0.23	$0.92	100.0%

Table 3-114 Real-time average marginal unit markup index (By offer price category adjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.14	($5.19)	6.2%	4.23	($4.14)	13.5%
$10 to $15	0.00	($0.13)	5.0%	(0.13)	($3.60)	0.5%
$15 to $20	0.03	$0.46	21.4%	(0.05)	($1.35)	1.3%
$20 to $25	0.05	$0.98	23.2%	0.04	$0.43	2.1%
$25 to $50	0.08	$2.30	37.1%	0.08	$2.81	41.6%
$50 to $75	0.21	$11.72	4.3%	0.09	$5.01	21.8%
$75 to $100	0.32	$26.51	0.8%	0.11	$8.17	9.4%
$100 to $125	0.31	$33.05	0.4%	0.16	$17.21	4.1%
$125 to $150	0.38	$51.06	0.2%	0.21	$27.88	1.6%
>= $150	0.20	$40.80	1.4%	0.15	$38.05	4.1%
All Offers	0.07	$2.36	100.0%	0.30	$5.16	100.0%

Table 3-115 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[175] Table 3-116 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first nine months of 2022, using unadjusted cost-based offers for coal units,

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

32.28 percent of marginal coal units had negative markups. In the first nine months of 2022, using adjusted cost-based offers for coal units, 17.11 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve decreased from 47.51 percent in the first nine months of 2021 to 42.83 percent in the first nine months of 2022 when using unadjusted cost based offers.

Table 3-115 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2021 and 2022

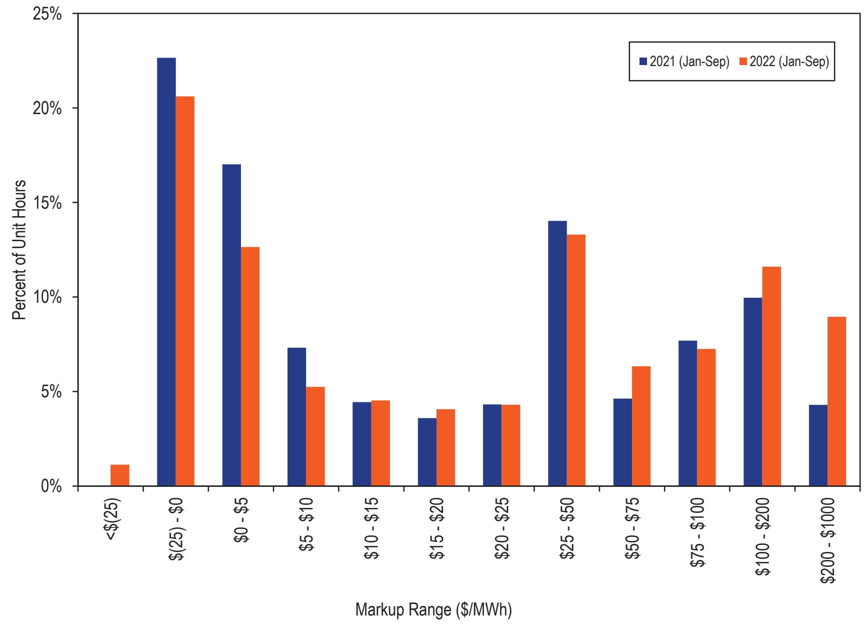
	2021 (Jan - Sep)			2022 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	50.47%	24.25%	25.29%	32.28%	17.11%	50.61%
Gas	47.51%	17.44%	35.05%	42.83%	18.25%	38.92%
Oil	4.92%	93.54%	1.54%	1.74%	98.12%	0.14%

Table 3-116 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	30.81%	13.98%	55.22%	17.89%	8.50%	73.60%
Gas	29.05%	8.47%	62.48%	28.52%	11.64%	59.83%
Oil	1.04%	92.60%	6.36%	1.72%	97.81%	0.47%

Figure 3-62 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2021 and 2022 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[176] Of the gas units offered in the PJM market in the first nine months of 2022, 21.7 percent of gas unit hours had a maximum markup that was negative and 20.5 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative decreased in the first nine months of 2022 compared to the first nine months of 2021 and the share of marginal gas units with negative markups also decreased.

Figure 3-62 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2021 and 2022



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

Figure 3-63 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2021 and 2022 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2022, 24.2 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 21.9 in the first nine months of 2021. The share of offered coal units with maximum markup that was negative increased in the first nine months of 2022 and the share of marginal coal units with negative markups decreased in the first nine months of 2022 compared to the first nine months of 2021.

Figure 3-63 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2021 and 2022

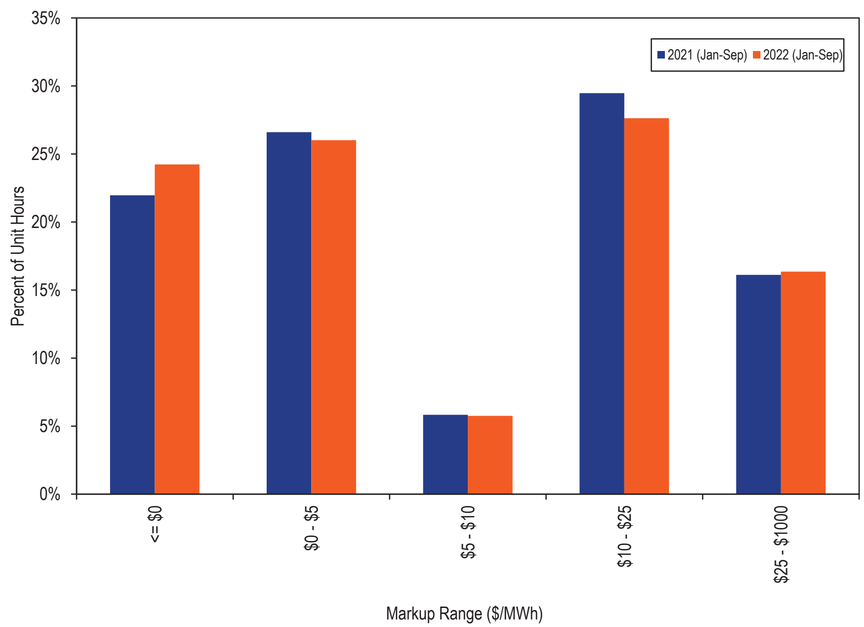
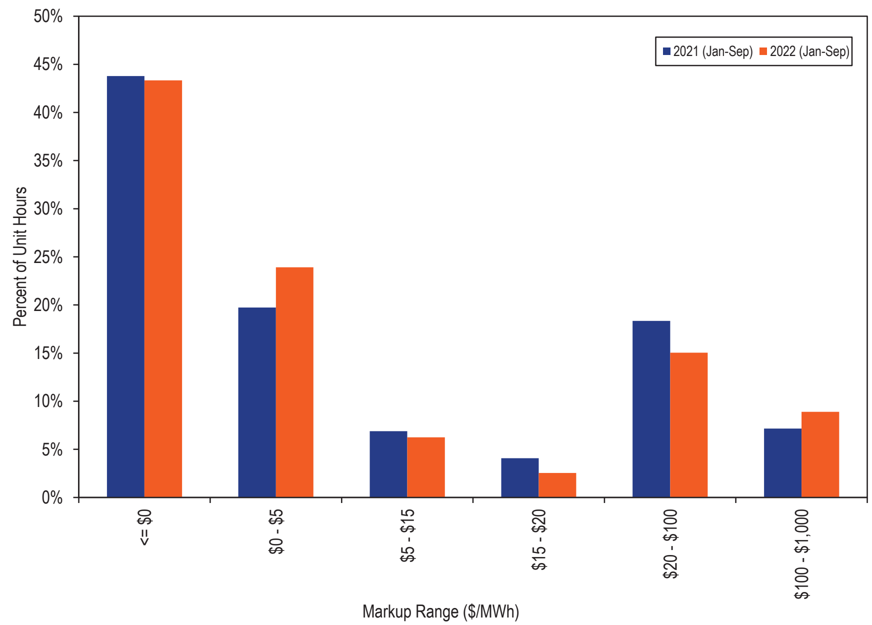


Figure 3-64 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2021 and the first nine months of 2022 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2022, 43.3 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 8.8 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-64 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2021 and 2022

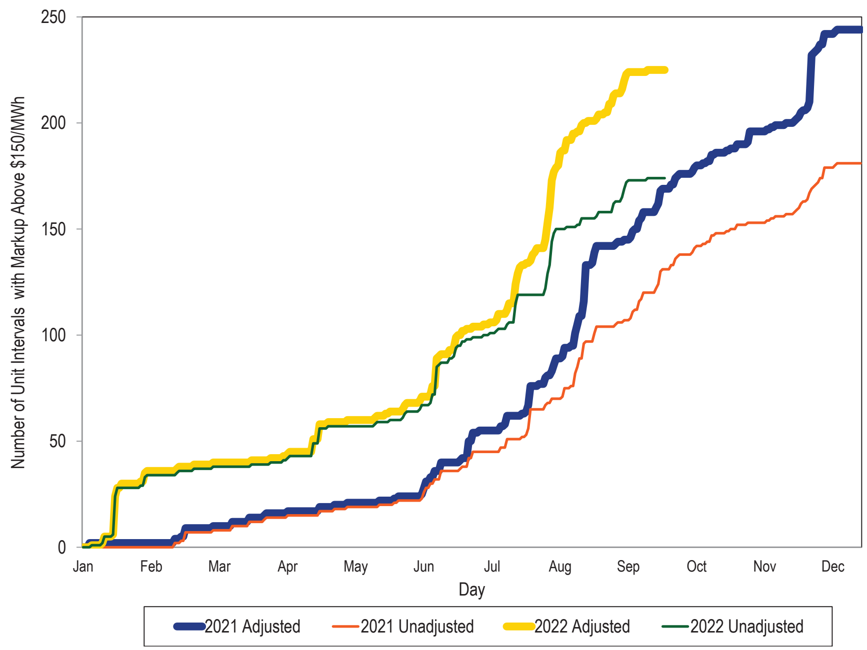


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion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

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-65 shows the number of marginal unit intervals in the first nine months of 2022 and 2021 with markup above $150 per MWh. For several of the marginal unit intervals with markups above $150 per MWh, the units failed the TPS test for the hour. These exercises of market power are a result of PJM's failure to address the issues with the offer capping process identified by the MMU. If PJM adopted the MMU's recommendations, these exercises of market power would not occur.

Figure 3-65 Cumulative number of unit intervals with markups above $150 per MWh: 2021 and January through September, 2022



Day-Ahead Markup Index

Table 3-117 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than $10 was positive ($6.93 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($21.72 per MWh) when using unadjusted cost-based offers. In the first nine months of 2022, the average markup index and average dollar markups increased significantly in all price offer categories except offer prices between $50 and $125 compared to the first nine months of 2021 due to high markups of some units during the cold weather days in January and February of 2022.

Some marginal units did have substantial markups. Using the unadjusted cost-based offers, 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 while the highest markup in the first nine months of 2021 was more than $100 per MWh.

Table 3-117 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.11	($1.07)	0.7%	8.35	$6.93	0.6%
$10 to $15	(0.01)	($0.53)	0.3%	2.00	$21.72	0.1%
$15 to $20	0.07	$0.91	2.7%	0.77	$13.10	0.4%
$20 to $25	0.00	($0.24)	3.7%	0.44	$8.38	0.3%
$25 to $50	0.04	$0.64	6.0%	0.13	$4.22	6.3%
$50 to $75	0.14	($1.06)	0.7%	0.09	$5.15	4.9%
$75 to $100	0.31	$26.61	0.1%	0.15	$11.18	2.2%
$100 to $125	0.24	$24.10	0.1%	0.25	$26.70	0.9%
$125 to $150	0.12	$15.86	0.0%	0.24	$32.79	0.3%
>= $150	0.05	$8.48	0.1%	0.17	$30.87	0.4%
All Offers	0.04	$0.60	14.3%	0.49	$8.42	16.5%

Table 3-118 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In the first nine months of 2022, 0.4 percent of day-ahead marginal resources had offers between $15 and $20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.14 in the first nine months of 2021, to 8.36 in the first nine months of 2022 in the offer price category less than $10.

Table 3-118 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.14	($0.84)	0.7%	8.36	$6.94	0.6%
$10 to $15	0.07	$0.72	0.3%	2.03	$22.30	0.1%
$15 to $20	0.15	$2.46	2.7%	0.84	$14.16	0.4%
$20 to $25	0.09	$1.84	3.7%	0.50	$10.02	0.3%
$25 to $50	0.12	$3.61	6.0%	0.20	$7.49	6.3%
$50 to $75	0.22	$4.25	0.7%	0.17	$10.19	4.9%
$75 to $100	0.37	$32.10	0.1%	0.22	$17.97	2.2%
$100 to $125	0.31	$32.15	0.1%	0.32	$34.34	0.9%
$125 to $150	0.16	$21.40	0.0%	0.31	$42.06	0.3%
>= $150	0.13	$24.55	0.1%	0.25	$51.98	0.4%
All Offers	0.12	$3.11	14.3%	0.56	$13.25	16.5%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly. Table 3-119 shows the caps on the three parts of cost-based and price-based offers.

Table 3-119 Cost-based and price-based offer caps

<table>
<tr><th>Offer Type</th><th>No Load and Start Cost Option</th><th>Incremental Offer Curve Cap</th><th>No Load Cost Cap</th><th>Start Cost Cap</th></tr>
<tr><td>Cost-Based</td><td>Cost-Based</td><td colspan="3">Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td rowspan="2">Price-Based</td><td>Cost-Based</td><td rowspan="2">$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td>Price-Based</td><td>No cap but can only be changed twice a year.</td><td>No cap but can only be changed twice a year.</td></tr>
</table>

Table 3-120 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2022, 89 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, three percentage points lower than in the first nine months of 2021.

Table 3-120 Number of units selecting cost-based and price-based no load and start costs: January through September, 2021 and 2022

	2021		2022	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	535	92%	511	89%
Price-Based	46	8%	62	11%
Total	581	100%	573	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-121 shows the average markup in the no load and start costs in the first nine months of 2021 and 2022. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were actually lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost but with very large positive markups on the start costs.

Table 3-121 No load and start cost markup: January through September, 2021 and 2022

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2021	Cost-Based	(8%)	(8%)	(9%)	(9%)
	Price-Based	(55%)	324%	377%	479%
2022	Cost-Based	(8%)	(8%)	(7%)	(7%)
	Price-Based	(52%)	111%	109%	129%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2022, 7.6 percent of the marginal units set prices based on cost-based offers, 0.5 percentage points higher than in the first nine months of 2021.

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

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers. FERC's decision to permit maintenance costs in cost-based offers that are not short run marginal costs also results in overstated cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[177]

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[178]

177 See 167 FERC ¶ 61,030 (2019).
178 See OA Schedule 2 § 1.1(a).

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

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

Fuel Cost Policies

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

Fuel Cost Policy Review

Table 3-122 shows the status of all fuel cost policies (FCP). As of September 30, 2022, 729 units (88 percent) had an FCP passed by the MMU and 96 units (12 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 20,991 MW. All units' FCPs were approved by PJM. As of September 30, 2022, 478 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[179]

179 See OA Schedule 2 § 2.1.

Table 3-122 FCP Status for PJM generating units: September 30, 2022

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	729	0	96	825
Total	729	0	96	825

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

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[180] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[181] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[182] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[183]

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

180 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
181 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
182 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
183 September 16th Filing at P 8.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are:[184] accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

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

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost polices include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost-Based Offer Penalties

Market Sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[185] Penalties are assessed when both PJM and the MMU are in agreement.

In the first nine months of 2022, 53 penalty cases were identified, 52 resulted in assessed cost-based offer penalties and one remains pending PJM's determination. These cases were for 50 units owned by 15 different companies. Table 3-124 shows the penalties by the year in which participants were notified.

184 See PJM Operating Agreement Schedule 2 § 2.3 (a).

185 See OA Schedule 2 § 6.

Table 3-123 Cost-based offer penalty cases by year notified: May 2017 through September 2022

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	137	24	5	0	124	25
2021	129	124	42	5	0	124	21
2022 (Jan-Sep)	53	52	16	0	1	50	15
Total	625	587	82	37	1	418	64

Since 2017, 625 penalty cases have been identified, 587 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, one remains pending PJM's determination and 82 were self identified by market sellers. The 587 cases were from 418 units owned by 64 different companies. The total penalties were $3.8 million, charged to units that totaled 115,831 available MW. The average penalty was $1.49 per available MW. This means that a 100 MW unit would have paid a penalty of $3,570.[186] In some cases where the penalized unit operates, the increase to LMP and/or uplift due to the incorrect offer exceeds the amount of the penalty. Table 3-124 shows the total cost-based offer penalties since 2017 by year.

Table 3-124 Cost-based offer penalties by year: May 2017 through September 2022

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	20	$556,826	16,930	$1.56
2018	127	34	$1,242,102	25,743	$2.28
2019	73	22	$378,245	15,073	$1.14
2020	140	26	$407,283	21,908	$0.85
2021	125	24	$753,463	24,808	$1.31
2022 (Jan-Sep)	54	14	$470,705	11,369	$1.73
Total	611	63	$3,808,624	115,831	$1.49

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

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

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.[187]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

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.

187 172 FERC ¶ 61,094 (2020).

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

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.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. In the first nine months of 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.[188]

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[189] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[190] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[191] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start.

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to

188 See PJM Manual 15: Cost Development Guidelines, Revision 39 (January 18, 2022).

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

190 167 FERC ¶ 61,030 (2019).

191 168 FERC ¶ 61,134 (2019).

electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data and PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.[192]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

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.

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 operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[193]

192 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

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

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

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

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

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many situations, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many market sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that market sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[194] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In the first nine months of 2022, no units qualified for an FMU adder.

Table 3-125 shows, by month, the number of FMUs and AUs from January 2021 through September 2022. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

Table 3-125 Number of frequently mitigated units and associated units (By month): January 2021 through September 2022

	2021				2022			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	1	0	1	0	0	0	0
February	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0
October	0	0	0	0				
November	0	0	0	0				
December	0	0	0	0				

For the 2020/2021 through 2022/2023 planning years, default Avoidable Cost Rates were not defined in the tariff. During this period, if a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) were greater than zero, and if the generating unit did not have an approved unit specific Avoidable Cost Rate, the generating unit would not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

194 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume II, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-126 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[195] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2022, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2022, the offers of one company resulted in 14.6 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 44.0 percent of the real-time load-weighted average PJM system LMP. In the first nine months of 2022, the offers of one company resulted in 14.2 percent of the peak hour real-time load-weighted PJM system LMP.

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

Table 3-126 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2021 and 2022

2021 (Jan - Sep)						2022 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	12.2%	12.2%	1	12.9%	12.9%	1	14.6%	14.6%	1	14.2%	14.2%
2	10.4%	22.6%	2	11.1%	24.0%	2	11.5%	26.0%	2	13.5%	27.6%
3	10.2%	32.8%	3	10.7%	34.6%	3	9.0%	35.0%	3	8.9%	36.6%
4	5.8%	38.6%	4	5.1%	39.7%	4	9.0%	44.0%	4	8.8%	45.3%
5	5.4%	44.0%	5	5.1%	44.8%	5	5.3%	49.3%	5	5.4%	50.7%
6	4.5%	48.5%	6	4.7%	49.5%	6	4.4%	53.7%	6	5.1%	55.9%
7	3.8%	52.3%	7	4.2%	53.7%	7	4.0%	57.7%	7	4.5%	60.3%
8	3.7%	56.0%	8	4.0%	57.7%	8	3.6%	61.3%	8	3.2%	63.5%
9	3.5%	59.5%	9	3.5%	61.2%	9	3.1%	64.5%	9	2.8%	66.4%
Other (76 companies)	40.5%	100.0%	Other (76 companies)	38.8%	100.0%	Other (75 ompanies)	35.5%	100.0%	Other (74 companies)	33.6%	100.0%

Figure 3-66 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for the first nine months of every year since 2012.

Figure 3-66 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2012 through 2022

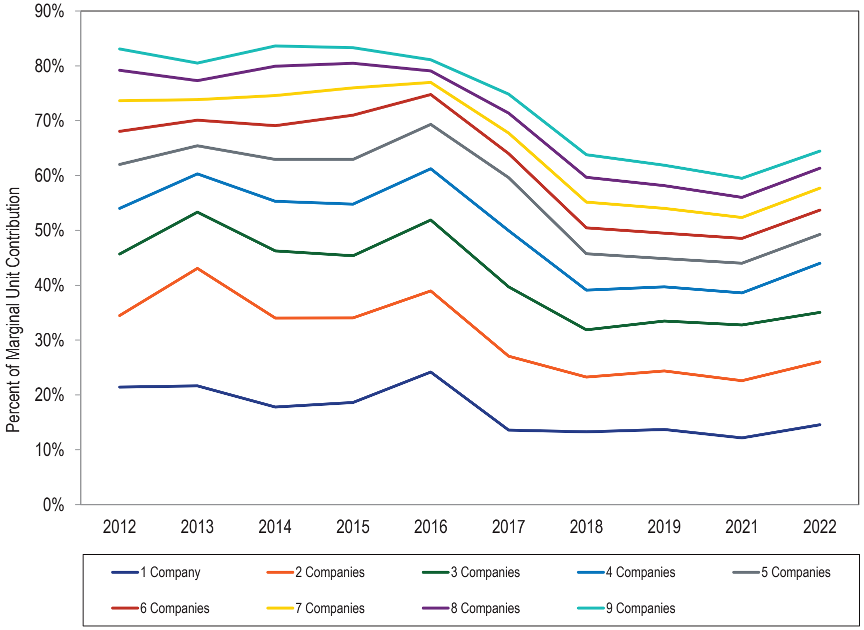


Table 3-127 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[196] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in the first nine months of 2022, the offers of one company contributed 9.7 percent of the day-ahead load-weighted average PJM system LMP and that the offers of the top four companies contributed 30.4 percent of the day-ahead load-weighted average PJM system LMP.

Table 3-127 Marginal resource contribution to day-ahead load-weighted LMP (By parent company): January through September, 2021 and 2022

2021 (Jan - Sep)						2022 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	6.1%	6.1%	1	7.4%	7.4%	1	9.7%	9.7%	1	9.8%	9.8%
2	5.8%	11.9%	2	7.4%	14.8%	2	8.4%	18.1%	2	9.1%	18.9%
3	5.0%	16.9%	3	4.4%	19.2%	3	6.4%	24.6%	3	8.5%	27.4%
4	4.7%	21.6%	4	4.2%	23.3%	4	5.9%	30.4%	4	7.5%	35.0%
5	4.6%	26.2%	5	4.1%	27.4%	5	4.7%	35.1%	5	5.5%	40.5%
6	4.0%	30.2%	6	4.0%	31.4%	6	4.4%	39.5%	6	4.2%	44.7%
7	3.6%	33.9%	7	3.9%	35.2%	7	3.3%	42.7%	7	3.4%	48.1%
8	3.5%	37.4%	8	3.8%	39.0%	8	3.0%	45.8%	8	3.3%	51.4%
9	3.1%	40.5%	9	3.7%	42.6%	9	3.0%	48.7%	9	3.3%	54.7%
Other (145 companies)	59.5%	100.0%	Other (140 companies)	57.4%	100.0%	Other (155 companies)	51.3%	100.0%	Other (144 companies)	45.3%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[197] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

196 Id.

197 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-128 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $3.60 per MWh in the first nine months of 2021 to $8.02 per MWh in the first nine months of 2022. The adjusted markup contribution of coal units in the first nine months of 2022 was $2.72 per MWh. The adjusted markup component of gas fired units in the first nine months of 2022 was $5.35 per MWh, an increase of $2.44 per MWh from the first nine months of 2021. The markup component of wind units was less than $0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2022, among the wind units that were marginal, 55.8 percent had negative offer prices.

Table 3-128 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through September, 2021 and 2022[198]

		2021 (Jan - Sep)		2022 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.28	$0.78	$1.96	$2.72
Gas	CC	$0.64	$1.96	$1.41	$3.74
Gas	CT	$0.47	$0.92	($0.09)	$1.48
Gas	RICE	($0.00)	$0.01	($0.02)	$0.04
Gas	Steam	($0.02)	$0.03	($0.03)	$0.10
Landfill Gas	CT	($0.00)	($0.00)	$0.00	$0.00
Municipal Waste	RICE	$0.00	$0.00	($0.00)	($0.00)
Oil	CC	$0.00	$0.00	($0.00)	($0.00)
Oil	CT	($0.00)	$0.01	($0.05)	$0.02
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.09)	($0.07)	($0.09)	($0.07)
Other	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	($0.04)	($0.04)	($0.00)	($0.00)
Total		$1.25	$3.60	$3.08	$8.02

Markup Component of Real-Time Price

Table 3-129 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-130 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first nine months of 2022, when using unadjusted cost-based offers, $3.08 per MWh of the PJM real-time load-weighted average LMP was attributable

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

to markup. Using adjusted cost-based offers, $8.02 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2022, the peak markup component was highest in July, $7.52 per MWh using unadjusted cost-based offers and peak markup component was highest in July, $15.04 per MWh using adjusted cost-based offers. This corresponds to 6.6 percent and 13.2 percent of the real-time, peak, load-weighted, average LMP in July.

Table 3-129 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2021 through September 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.46)	($0.30)	($0.60)	$1.55	$0.45	$2.55
Feb	($0.53)	$0.06	($1.12)	$2.24	$2.13	$2.35
Mar	$0.02	$0.16	($0.13)	$1.50	$1.29	$1.73
Apr	($1.69)	($2.56)	($0.72)	$3.34	$4.57	$2.12
May	($0.02)	$0.62	($0.62)	$2.27	$3.71	$0.89
Jun	$1.75	$2.76	$0.58	$4.62	$7.03	$1.60
Jul	$2.61	$3.37	$1.80	$5.07	$7.52	$2.73
Aug	$4.83	$6.68	$2.71	$5.20	$4.79	$5.71
Sep	$3.30	$4.19	$2.34	$1.20	$0.82	$1.60
Oct	$4.43	$5.52	$3.35			
Nov	$3.15	$4.12	$2.20			
Dec	$1.89	$2.46	$1.26			
Total	$1.69	$2.41	$0.94	$3.08	$3.71	$2.42

Table 3-130 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2021 through September 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.47	$1.73	$1.24	$5.65	$4.58	$6.62
Feb	$2.41	$3.21	$1.60	$5.49	$5.36	$5.61
Mar	$1.63	$1.85	$1.39	$4.56	$4.52	$4.61
Apr	($0.08)	($0.97)	$0.91	$7.36	$8.91	$5.82
May	$1.93	$2.75	$1.17	$7.39	$9.35	$5.49
Jun	$3.96	$5.22	$2.52	$10.36	$13.76	$6.10
Jul	$5.11	$6.20	$3.95	$11.25	$15.04	$7.64
Aug	$7.75	$9.92	$5.27	$12.01	$12.40	$11.54
Sep	$6.52	$7.71	$5.23	$6.77	$7.04	$6.49
Oct	$8.34	$9.96	$6.73			
Nov	$6.43	$7.73	$5.16			
Dec	$4.28	$4.92	$3.57			
Total	$4.23	$5.18	$3.24	$8.02	$9.25	$6.75

Hourly Markup Component of Real-Time Prices

Figure 3-67 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2021 and the first nine months of 2022. Figure 3-68 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2021 and the first nine months of 2022.

Figure 3-67 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2021 and January through September, 2022

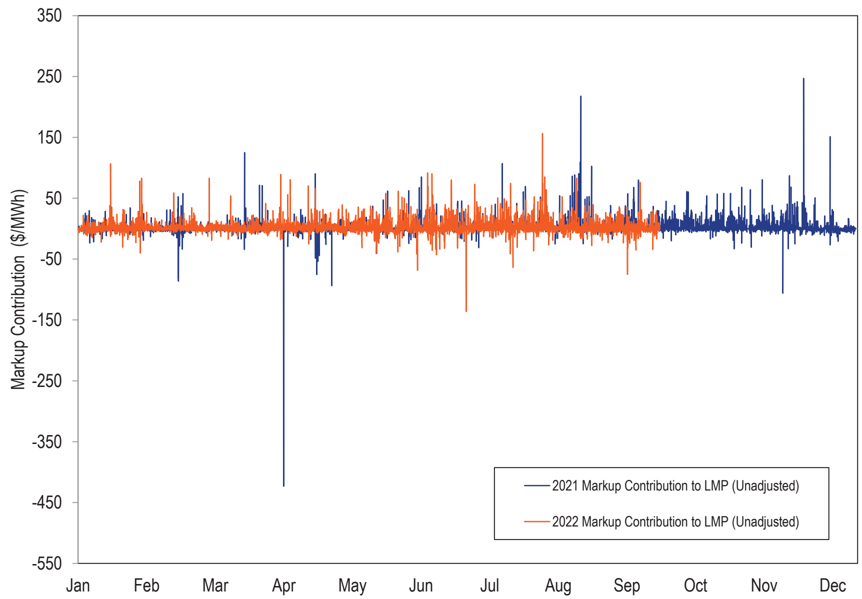
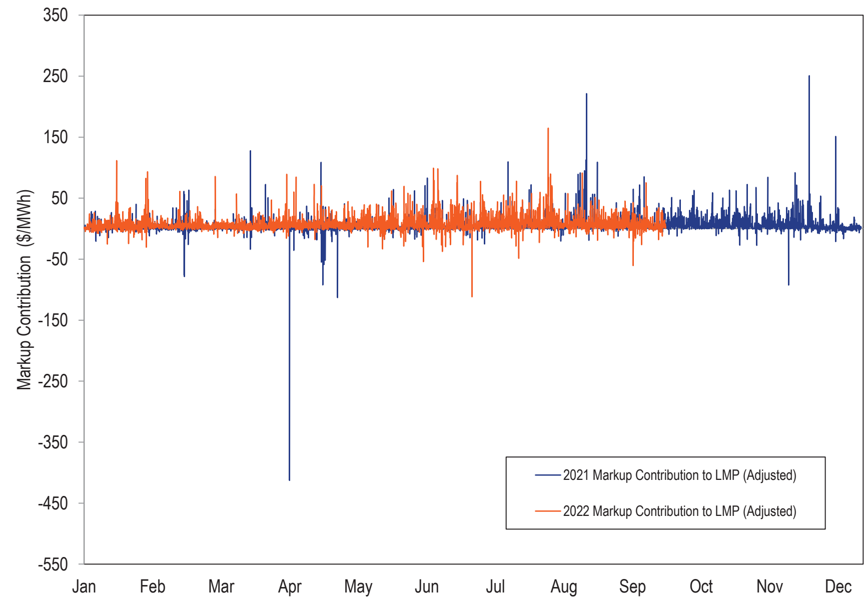


Figure 3-68 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2021 and January through September, 2022



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2021 and 2022 in Table 3-131 and for adjusted offers in Table 3-132.[199] The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2022, was in the PECO Control Zone, $2.15 per MWh, while the highest was in the BGE Control Zone, $4.08 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2022, was in the DPL Control Zone, $2.40 per MWh, while the highest was in the BGE Control Zone, $4.91 per MWh.

199 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-131 Real-time average zonal markup component (Unadjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.80	$1.44	$0.15	$2.34	$2.60	$2.07
AEP	$1.34	$2.08	$0.58	$3.16	$3.97	$2.33
APS	$1.31	$2.04	$0.56	$3.19	$3.85	$2.50
ATSI	$1.38	$2.06	$0.67	$3.04	$3.78	$2.28
BGE	$1.57	$2.31	$0.81	$4.08	$4.91	$3.21
COMED	$1.34	$2.13	$0.54	$2.56	$3.40	$1.70
DAY	$1.40	$2.11	$0.68	$3.24	$4.05	$2.39
DOM	$1.29	$2.06	$0.50	$3.69	$4.24	$3.11
DPL	$1.01	$1.74	$0.26	$2.15	$2.40	$1.90
DUKE	$1.31	$1.97	$0.63	$3.16	$3.99	$2.31
DUQ	$1.30	$1.94	$0.64	$3.05	$3.84	$2.23
EKPC	$1.29	$1.96	$0.61	$3.17	$3.97	$2.33
JCPLC	$0.89	$1.47	$0.28	$2.47	$2.77	$2.16
MEC	$1.33	$2.27	$0.35	$3.25	$3.63	$2.85
OVEC	$1.30	$1.80	$0.78	$3.01	$3.77	$2.23
PE	$1.27	$2.03	$0.48	$2.81	$3.44	$2.17
PECO	$0.85	$1.52	$0.16	$2.24	$2.52	$1.95
PEPCO	$1.58	$2.20	$0.95	$3.88	$4.63	$3.11
PPL	$1.03	$1.73	$0.31	$2.90	$3.29	$2.49
PSEG	$0.97	$1.58	$0.34	$2.72	$3.21	$2.22
REC	$1.28	$2.05	$0.49	$2.99	$3.67	$2.29

Table 3-132 Real-time average zonal markup component (Adjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$2.96	$3.74	$2.14	$6.41	$6.83	$5.97
AEP	$3.76	$4.73	$2.75	$8.22	$9.71	$6.69
APS	$3.73	$4.70	$2.73	$8.32	$9.61	$6.97
ATSI	$3.78	$4.69	$2.85	$8.03	$9.42	$6.58
BGE	$4.25	$5.29	$3.19	$10.10	$11.88	$8.26
COMED	$3.68	$4.69	$2.64	$7.28	$8.88	$5.62
DAY	$3.93	$4.90	$2.93	$8.45	$9.97	$6.88
DOM	$3.83	$4.87	$2.75	$9.40	$10.76	$7.99
DPL	$3.20	$4.07	$2.31	$6.35	$6.78	$5.90
DUKE	$3.74	$4.66	$2.80	$8.24	$9.76	$6.67
DUQ	$3.65	$4.49	$2.78	$7.94	$9.38	$6.46
EKPC	$3.70	$4.61	$2.76	$8.23	$9.72	$6.69
JCPLC	$3.07	$3.83	$2.29	$6.69	$7.20	$6.15
MEC	$3.66	$4.86	$2.42	$8.08	$8.95	$7.18
OVEC	$3.66	$4.38	$2.91	$7.98	$9.40	$6.51
PE	$3.59	$4.56	$2.59	$7.57	$8.70	$6.40
PECO	$2.97	$3.80	$2.13	$6.18	$6.58	$5.77
PEPCO	$4.15	$5.03	$3.25	$9.63	$11.18	$8.02
PPL	$3.25	$4.16	$2.30	$7.38	$8.12	$6.60
PSEG	$3.21	$4.04	$2.36	$6.98	$7.71	$6.23
REC	$3.62	$4.69	$2.53	$7.45	$8.48	$6.38

Markup by Real-Time Price Levels

Table 3-133 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-133 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($10.48)	0.0%	($6.54)	0.1%
$10 to $15	($1.56)	0.7%	($5.71)	0.1%
$15 to $20	($0.93)	15.6%	($3.42)	0.3%
$20 to $25	($0.90)	25.3%	($2.03)	0.6%
$25 to $50	$0.32	47.0%	($0.12)	33.4%
$50 to $75	$5.37	7.1%	$1.19	31.7%
$75 to $100	$10.93	2.2%	$3.89	16.6%
$100 to $125	$18.34	1.1%	$5.19	8.4%
$125 to $150	$28.61	0.4%	$9.79	4.2%
>= $150	$39.41	0.5%	$17.58	4.6%

Table 3-134 Real-time markup contribution (By load-weighted LMP category, adjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($9.88)	0.0%	($5.41)	0.1%
$10 to $15	($0.35)	0.7%	($3.65)	0.1%
$15 to $20	$0.53	15.6%	($1.69)	0.3%
$20 to $25	$0.94	25.3%	($0.04)	0.6%
$25 to $50	$2.77	47.0%	$3.05	33.4%
$50 to $75	$8.79	7.1%	$5.60	31.7%
$75 to $100	$15.00	2.2%	$9.70	16.6%
$100 to $125	$22.92	1.1%	$12.43	8.4%
$125 to $150	$33.67	0.4%	$17.80	4.2%
>= $150	$43.08	0.5%	$25.53	4.6%

Markup by Company

Table 3-135 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2022, when using unadjusted cost-based offers, the markup of one company accounted for 1.2 percent of the load-weighted average LMP, the markup of the top five companies accounted for 3.5 percent of the load-weighted average LMP and the markup of all companies accounted for 4.0 percent of the load-weighted average LMP. The top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup increased in the first nine months of 2022. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP also increased in the first nine months of 2022. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-135 Markup component of real-time load-weighted average LMP by Company: January through September, 2021 and 2022

	2021 (Jan - Sep)				2022 (Jan - Sep)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.46	1.3%	$0.71	2.0%	$0.92	1.2%	$1.48	1.9%
Top 2 Companies	$0.90	2.5%	$1.34	3.8%	$1.81	2.3%	$2.57	3.3%
Top 3 Companies	$1.11	3.1%	$1.64	4.6%	$2.33	3.0%	$3.33	4.3%
Top 4 Companies	$1.26	3.5%	$1.94	5.4%	$2.70	3.5%	$3.90	5.0%
Top 5 Companies	$1.37	3.9%	$2.20	6.2%	$2.97	3.8%	$4.46	5.7%
All Companies	$1.25	3.5%	$3.60	10.1%	$3.08	4.0%	$8.02	10.3%

Day-Ahead Markup

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

The markup component of the PJM day-ahead load-weighted average LMP by primary fuel and unit type is shown in Table 3-136. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 44.1 percent of marginal resources, INCs were 18.3 percent of marginal resources and DECs were 20.8 percent of marginal resources in the first nine months of 2022.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder. Table 3-136 shows the markup component of LMP for marginal generating resources. Generating resources were only 16.5 percent of marginal resources in the first nine months of 2022. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from $0.71 to $2.54 per MWh and increased for gas fired CC units from $1.40 to $2.47 per MWh.[200]

Table 3-136 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: January through September, 2021 and 2022

		2021 (Jan - Sep)			2022 (Jan - Sep)		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	$0.12	$0.71	34.7%	$1.79	$2.54	23.7%
Gas	CC	$0.42	$1.40	54.5%	$0.92	$2.47	57.3%
Gas	CT	$0.05	$0.05	1.4%	($0.03)	$0.12	4.5%
Gas	RICE	($0.00)	$0.00	0.7%	($0.01)	$0.01	0.9%
Gas	Steam	($0.00)	$0.05	3.2%	($0.13)	$0.00	3.8%
Municipal Waste	RICE	$0.00	$0.00	0.2%	$0.00	$0.00	0.0%
Municipal Waste	Steam	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Oil	CC	$0.00	$0.00	0.0%	($0.00)	$0.00	0.1%
Oil	CT	$0.00	$0.00	0.3%	$0.00	$0.01	2.0%
Oil	RICE	$0.00	$0.00	0.1%	$0.00	$0.01	0.3%
Oil	Steam	($0.12)	($0.10)	0.2%	($0.02)	($0.02)	0.0%
Other	Solar	$0.04	$0.04	0.3%	$0.30	$0.30	0.4%
Other	Steam	$0.00	$0.00	0.2%	$0.00	$0.00	0.1%
Uranium	Steam	$0.00	$0.00	0.2%	$0.00	$0.00	0.0%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.32	$0.32	3.9%	$0.43	$0.43	6.9%
Total		$0.84	$2.48	100.0%	$3.27	$5.89	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-137 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In the first nine months of 2022, when using unadjusted cost-based offers, $3.27 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2022, the peak markup component was highest in June, $7.21 per MWh using unadjusted cost-based offers.

200 May 21, 2022, HE 1700, September 15, 2022, HE 0200, and September 21, 2022, HE 1500 had abnormal unit participant factor (UPF) values and the marginal resources data in that hour was removed from 2022 pricing run data.

Table 3-137 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: January through September, 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.41)	($0.19)	($0.59)	$4.44	$6.17	$2.85
Feb	($0.30)	$2.25	($2.91)	$1.28	$1.28	$1.28
Mar	$0.62	$0.56	$0.69	$3.45	$4.86	$1.92
Apr	$0.38	$0.84	($0.14)	$3.90	$3.44	$4.35
May	$1.06	$1.26	$0.88	$2.86	$5.11	$0.67
Jun	$0.16	$0.41	($0.13)	$4.82	$7.21	$1.80
Jul	$1.97	$3.19	$0.65	$1.27	($0.50)	$2.98
Aug	$1.59	$2.32	$0.73	$3.51	$4.79	$1.92
Sep	$4.62	$6.89	$2.13	$4.03	$5.60	$2.37
Oct	$9.74	$16.13	$3.32			
Nov	$4.72	$4.23	$5.21			
Dec	$0.73	$2.47	($1.23)			
Total	$1.99	$3.24	$0.67	$3.27	$4.24	$2.25

Table 3-138 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first nine months of 2022, when using adjusted cost-based offers, $5.89 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In the first nine months of 2022, the peak markup component was highest in January, $10.34 per MWh using adjusted cost-based offers.

Table 3-138 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: January through September, 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.16	$1.31	$1.03	$8.04	$10.34	$5.93
Feb	$2.21	$4.69	($0.33)	$2.83	$1.95	$3.69
Mar	$1.78	$1.72	$1.84	$6.39	$8.58	$4.02
Apr	$1.64	$1.98	$1.26	$5.93	$5.32	$6.55
May	$2.45	$2.58	$2.33	$5.67	$7.51	$3.88
Jun	$1.49	$1.75	$1.19	$7.42	$9.51	$4.77
Jul	$3.62	$4.73	$2.41	$4.20	$2.76	$5.59
Aug	$3.40	$3.99	$2.71	$6.78	$7.85	$5.44
Sep	$8.51	$10.26	$6.58	$5.44	$5.42	$5.45
Oct	$13.77	$19.69	$7.82			
Nov	$8.88	$8.22	$9.53			
Dec	$4.14	$5.84	$2.21			
Total	$4.30	$5.41	$3.14	$5.89	$6.67	$5.06

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-139. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-140. The smallest zonal all hours average markup component using adjusted cost-based offers for the first nine months of 2022 was in the PEPCO Zone, $4.33 per MWh, while the highest was in the COMED Control Zone, $7.01 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the MEC Control Zone, $3.56 per MWh, while the highest was in the COMED Control Zone, $8.68 per MWh.

Table 3-139 Day-ahead average zonal markup component (Unadjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.58	$1.00	$0.14	$2.52	$2.26	$2.78
AEP	$0.78	$1.63	($0.10)	$3.66	$4.87	$2.40
APS	$0.64	$1.47	($0.23)	$3.31	$4.41	$2.17
ATSI	$0.27	$0.71	($0.19)	$2.81	$3.39	$2.19
BGE	$1.20	$2.46	($0.13)	$2.24	$2.86	$1.61
COMED	$0.73	$1.28	$0.15	$4.00	$5.45	$2.46
DAY	$0.99	$1.88	$0.01	$3.54	$4.66	$2.31
DOM	$0.94	$1.79	$0.08	$2.34	$3.31	$1.36
DPL	$0.35	$0.35	$0.36	$3.02	$3.64	$2.39
DUKE	$0.88	$1.71	($0.00)	$3.95	$5.14	$2.69
DUQ	$0.33	$0.71	($0.08)	$3.07	$4.03	$2.06
EKPC	$2.30	$4.87	($0.30)	$3.68	$4.80	$2.56
JCPLC	$0.60	$0.98	$0.18	$2.72	$2.76	$2.66
MEC	$0.59	$1.10	$0.03	$1.67	$1.07	$2.32
OVEC	$0.44	$0.77	($0.05)	$3.96	$4.23	$3.74
PE	$0.42	$0.81	($0.02)	$3.80	$5.07	$2.33
PECO	$0.51	$0.78	$0.22	$2.87	$2.89	$2.84
PEPCO	$1.09	$2.12	($0.03)	$2.19	$2.23	$2.15
PPL	$0.59	$1.02	$0.14	$3.04	$3.33	$2.74
PSEG	$0.62	$0.94	$0.28	$3.23	$3.70	$2.73
REC	$0.60	$1.04	$0.09	$2.20	$2.23	$2.17

Table 3-140 Day-ahead average zonal markup component (Adjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)			2022 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$2.36	$2.84	$1.85	$5.40	$5.27	$5.53
AEP	$2.39	$3.14	$1.61	$6.67	$7.98	$5.30
APS	$2.27	$3.02	$1.49	$6.12	$7.13	$5.08
ATSI	$1.98	$2.34	$1.59	$5.29	$5.46	$5.11
BGE	$2.77	$3.83	$1.65	$4.37	$4.17	$4.57
COMED	$2.38	$2.92	$1.81	$7.01	$8.68	$5.23
DAY	$2.68	$3.48	$1.81	$6.25	$7.33	$5.07
DOM	$2.55	$3.19	$1.90	$4.97	$5.67	$4.27
DPL	$2.00	$1.99	$2.02	$5.65	$6.38	$4.90
DUKE	$2.48	$3.19	$1.73	$6.90	$8.20	$5.52
DUQ	$1.95	$2.25	$1.63	$5.77	$6.55	$4.94
EKPC	$3.84	$6.12	$1.53	$6.64	$7.96	$5.32
JCPLC	$2.37	$2.77	$1.92	$5.55	$5.79	$5.30
MEC	$2.13	$2.54	$1.68	$4.38	$3.56	$5.28
OVEC	$2.20	$2.49	$1.77	$6.41	$6.61	$6.26
PE	$2.06	$2.42	$1.66	$6.20	$7.16	$5.09
PECO	$2.24	$2.55	$1.91	$5.69	$5.82	$5.54
PEPCO	$2.70	$3.54	$1.79	$4.33	$3.70	$5.02
PPL	$2.21	$2.60	$1.78	$6.07	$6.69	$5.41
PSEG	$2.38	$2.74	$1.99	$5.98	$6.58	$5.34
REC	$2.29	$2.73	$1.79	$4.35	$3.96	$4.79

Markup by Day-Ahead Price Levels

Table 3-141 and Table 3-142 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-141 Day-ahead average markup component (By LMP category, unadjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
$10 to $15	($0.00)	0.1%	$0.00	0.0%
$15 to $20	$0.03	11.4%	($0.00)	0.1%
$20 to $25	($0.06)	25.1%	($0.00)	0.1%
$25 to $50	$0.42	52.8%	$0.54	28.0%
$50 to $75	$0.25	8.0%	$0.59	37.4%
$75 to $100	$0.11	1.5%	$0.84	17.2%
$100 to $125	$0.04	0.6%	$0.62	10.0%
$125 to $150	($0.00)	0.3%	$0.46	3.7%
>= $150	$0.06	0.1%	$0.23	3.5%

Table 3-142 Day-ahead average markup component (By LMP category, adjusted): January through September, 2021 and 2022

	2021 (Jan - Sep)		2022 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
$10 to $15	($0.00)	0.1%	$0.00	0.0%
$15 to $20	$0.13	11.4%	$0.00	0.1%
$20 to $25	$0.28	25.1%	$0.00	0.1%
$25 to $50	$1.38	52.8%	$1.15	28.0%
$50 to $75	$0.41	8.0%	$1.38	37.4%
$75 to $100	$0.13	1.5%	$1.47	17.2%
$100 to $125	$0.06	0.6%	$0.97	10.0%
$125 to $150	$0.01	0.3%	$0.58	3.7%
>= $150	$0.06	0.1%	$0.32	3.5%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which that participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[201]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, *P* is the market price, and *MC* is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. As HHI decreases, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices can reach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that

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

connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[202] Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[203]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $74.77 per MWh and an average HHI of 690 in the first nine months of 2022, average PJM prices would theoretically range from $90 to $114 per MWh using the elasticity range of -0.2 to -0.4.[204] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $77.84 per MWh with markups at 3.9 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup.

202 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

203 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

204 The average HHI is found in Table 3-92. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-72.

With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-143 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2022, 6.2 percent of real-time marginal unit intervals and 6.6 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-143 Percent of real-time marginal unit intervals with markup and local market power: January through September, 2022

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	22.6%	4.4%	27.0%	29.9%	7.9%	37.8%
Zero Markup	16.1%	5.2%	21.4%	15.3%	9.6%	24.9%
$0 to $5	12.0%	1.4%	13.4%	15.5%	3.2%	18.7%
$5 to $10	6.8%	0.9%	7.8%	5.5%	0.7%	6.2%
$10 to $15	6.3%	1.0%	7.2%	2.8%	0.4%	3.2%
$15 to $20	5.0%	0.7%	5.7%	2.6%	0.3%	2.9%
$20 to $25	4.6%	0.6%	5.2%	1.5%	0.3%	1.8%
$25 to $50	6.9%	1.2%	8.1%	2.1%	0.6%	2.7%
$50 to $75	2.4%	0.6%	3.0%	0.6%	0.3%	0.9%
$75 to $100	0.6%	0.1%	0.8%	0.2%	0.1%	0.4%
Above $100	0.3%	0.1%	0.4%	0.2%	0.2%	0.4%
Total Positive Markup	45.0%	6.6%	51.6%	31.1%	6.2%	37.3%
Total	83.7%	16.3%	100.0%	76.3%	23.7%	100.0%

The markup of marginal units was zero or negative in 62.8 percent of real-time marginal unit intervals and 48.4 percent of day-ahead marginal unit intervals in the first nine months of 2022. Pivotal suppliers in the aggregate market also set prices with high markups in the first nine months of 2022. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges, and are treated for uplift purposes as equivalent to a decrement bid (DEC) at the sink point of the UTC.[2]

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[3] [4] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design incorporates efficient prices with minimal uplift payments. Actual results in PJM do not minimize actual uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[5]

Overview

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.

1 Loss exists when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 See 172 FERC ¶ 61,046 (2020).

3 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

4 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

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

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.

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.)[6]
- 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.)

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.

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

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.[7] 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.[8] 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.[9] The uplift payments for UTCs began on November 1, 2020.[10] 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

7 See 173 FERC ¶ 61,244 (2020).

8 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).

9 See 172 FERC ¶ 61,046 (2020).

10 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).

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 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.

Energy Uplift Credits Results

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift.

Table 4-1 shows the totals for each credit category for the first nine months of 2021 and 2022.[11] In the first nine months of 2022, energy uplift credits increased by $49.4 million or 37.7 percent compared to 2021.

The dispatch differential lost opportunity cost is a credit paid to resources that, in order to accommodate inflexible fast start resources, are dispatched down to an output below the level that is economic for them at the market prices that result from fast start pricing. Because fast start pricing was introduced on September 1, 2021, the dispatch differential lost opportunity cost credit did not exist for the first eight months of 2021, and the 2021 data in this report include only one month (September) of these credits.

11 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on October 13, 2022.

Table 4-1 Energy uplift credits by category: January through September, 2021 and 2022[12]

Category	Type	(Jan - Sep) 2021 Credits (Millions)	(Jan - Sep) 2022 Credits (Millions)	Change	Percent Change	2021 Share	2022 Share
Day-Ahead	Generators	$10.8	$35.3	$24.5	227.6%	8.2%	19.5%
	Imports	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$97.1	$113.4	$16.4	16.8%	74.1%	62.8%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$4.7	$1.2	($3.5)	(73.9%)	3.6%	0.7%
	Lost Opportunity Cost	$17.5	$25.4	$7.8	44.7%	13.4%	14.0%
	Dispatch Differential Lost Opportunity Cost	$0.1	$3.6	NA	NA	NA	2.0%
Reactive Services	Day-Ahead	$0.3	$0.7	$0.5	185.5%	0.2%	0.4%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.2	$0.2	1,357.1%	0.0%	0.1%
	Reactive Services	$0.5	$0.3	($0.2)	(44.8%)	0.4%	0.1%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Testing	$0.2	$0.3	$0.1	71.4%	0.2%	0.2%
Total		$131.1	$180.5	$49.4	37.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for the first nine months of 2021 and 2022. A combination of factors led to increased uplift payments for day ahead operating reserves and balancing operating reserves including increased need for reliability generation by steam (coal and other fuels) units, and higher fuel prices.

Uplift credits paid to combustion turbines increased by $8.8 million or 7.7 percent in the first nine months of 2022 compared to the same period in 2021. In the first nine months of 2022, CTs received 80.2 percent of lost opportunity cost credits, which increased by $7.8 million or 44.7 percent from the first nine months of 2021.

Uplift credits paid to steam coal units increased by $20.1 million or 202.7 percent during the first nine months of 2022 compared to the same time period of 2021. A small number of coal units committed for reliability in the BGE and PPL Zones were responsible for 64.1 percent of day-ahead credits, and were responsible for 79.6 percent of the increase in day-ahead credits. Uplift credits paid to other (gas or oil fired) steam units increased by $12.3 million or 492.8 percent during the first nine months of 2022 compared to the same time period of 2021. The increase in payments to non-coal burning steam units can be attributed to a small number of units in the PEPCO, BGE, and PPL Zones. Non-coal burning steam units were responsible for 34.1 percent of the increase in day-ahead credits during the first nine months of 2022 compared to the first nine months of 2021. In the first nine months of 2022, non-coal burning steam units received $14.7 million, or 8.2 percent of total credits, compared to $2.5 million and 1.9 percent in the first nine months of 2021.

12 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.

In the first nine months of 2022, uplift credits to wind units were $0.6 million, up by 193.5 percent compared to 2021. During the first nine months of 2022, uplift credits to combined cycle units increased by $6.3 million or 154.0 percent compared to the same period last year.

Table 4-2 Total energy uplift credits by unit type January through September, 2021 and 2022[13 14]

Unit Type	(Jan - Sep) 2021 Credits (Millions)	(Jan - Sep) 2022 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2021 Share	(Jan - Sep) 2022 Share
Combined Cycle	$4.1	$10.3	$6.3	154.0%	3.1%	5.7%
Combustion Turbine	$113.2	$121.9	$8.8	7.7%	86.3%	67.6%
Diesel	$1.2	$1.9	$0.7	61.4%	0.9%	1.0%
Hydro	$0.1	$0.9	$0.8	1,236.0%	0.0%	0.5%
Nuclear	$0.0	$0.0	($0.0)	(93.2%)	0.0%	0.0%
Solar	$0.0	$0.1	$0.1	1,029.5%	0.0%	0.0%
Steam - Coal	$9.9	$30.1	$20.1	202.7%	7.6%	16.7%
Steam - Other	$2.5	$14.7	$12.3	492.8%	1.9%	8.2%
Wind	$0.2	$0.6	$0.4	193.5%	0.1%	0.3%
Total	$131.1	$180.5	$49.4	37.7%	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2022. The characteristics of the different unit types explain why uplift in specific categories is paid primarily to specific unit types. For example, the highest share of day-ahead credits, 69.2 percent, went to steam units because steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead credits. The PJM market rules permit combustion turbines, unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 86.4 percent of balancing credits and 80.2 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-3 Energy uplift credits by unit type: January through September, 2022

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	2.4%	5.0%	0.0%	0.0%	10.7%	0.0%	0.0%	25.6%	28.5%
Combustion Turbine	1.6%	86.4%	0.0%	91.1%	80.2%	20.3%	0.0%	74.3%	39.8%
Diesel	0.0%	0.8%	0.0%	6.6%	3.4%	0.7%	0.0%	0.1%	0.4%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.1%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.1%
Steam - Coal	69.2%	3.9%	0.0%	0.0%	2.4%	39.6%	0.0%	0.0%	5.2%
Steam - Other	26.8%	4.0%	0.0%	0.0%	1.0%	39.4%	0.0%	0.0%	1.0%
Wind	0.0%	0.0%	0.0%	2.3%	1.9%	0.0%	0.0%	0.0%	1.0%
Total (Millions)	$35.3	$113.4	$0.0	$1.2	$25.4	$1.2	$0.0	$0.3	$3.6

13 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.
14 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, the reactive transfer interface control needed to maintain system reliability in a zone, or reactive service.[15] Participants can submit units as self scheduled, meaning that the unit must be committed, but a unit submitted as self scheduled (must run) by a participant is not eligible for day-ahead operating reserve credits.[16] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal.

Table 4-4 shows total day-ahead generation and day-ahead generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 109.3 percent from the first nine months of 2021 to the first nine months of 2022, from 1,079.0 GWh in 2021 to 2,258.4 GWh in 2022. The increase in day-ahead generation committed for reliability by PJM was due to an increased need to commit uneconomic units in the BGE, PPL, and PEPCO Zones for reliability.

Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift (operating reserve credits). Total day-ahead operating reserve credits in the first nine months of 2021 were $35.3 million. The top 10 units received $32.9 million or 93.3 percent of all day-ahead operating reserve credits. These units were large units with operating parameters less flexible than PLS parameters, including long minimum run times.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In the first nine months of 2022, 58.8 percent of the day-ahead generation committed for reliability by PJM was paid day-ahead operating reserve credits. The remaining 41.2 percent of the day-ahead generation committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-4 Day-ahead generation committed for reliability (GWh): January 2021 through September 2022

	2021			2022			Percent Change of PJM Day-Ahead Must Run Generation
	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	
Jan	73,635	95	0.1%	81,373	0	0.0%	
Feb	71,354	13	0.0%	68,253	37	0.1%	191.6%
Mar	64,713	209	0.3%	66,579	4	0.0%	(98.2%)
Apr	57,137	13	0.0%	57,663	8	0.0%	(38.2%)
May	60,957	26	0.0%	63,309	389	0.6%	1,407.1%
Jun	72,987	126	0.2%	70,849	417	0.6%	231.9%
Jul	80,025	103	0.1%	81,815	594	0.7%	479.2%
Aug	81,744	86	0.1%	80,627	432	0.5%	403.9%
Sep	66,913	410	0.6%	67,871	378	0.6%	(7.7%)
Oct	61,610	15	0.0%				NA
Nov	62,746	181	0.3%				NA
Dec	69,036	96	0.1%				NA
Total (Jan - Sep)	629,465	1,079	0.2%	638,339	2,258	0.4%	109.3%
Total	822,857	1,372	0.2%	638,339	2,258	0.4%	109.3%

15 See OA Schedule 1 § 3.2.3(b).

16 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through September, 2022

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	17.9	19.6	37.5
Feb	0.0	3.7	0.0	3.7
Mar	0.0	8.1	0.0	8.1
Apr	17.1	79.9	291.5	388.5
May	0.0	214.3	202.7	416.9
Jun	0.0	384.3	209.6	593.9
Jul	0.0	268.8	162.7	431.5
Aug	0.0	332.8	45.4	378.2
Sep	0.0	0.0	0.0	0.0
Total (Jan - Sep)	17.1	1,309.7	931.6	2,258.4
Share	0.8%	58.0%	41.2%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2022 were $35.3 million, of which $32.1 million or 91.1 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. There was no additional day-ahead operating reserves paid to units scheduled to provide reactive services.

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits) and its real-time offer (startup, no load, and energy offer). Combustion turbines (CTs) received $97.9 million or 86.4 percent of all balancing operating reserve (BOR) credits in the first nine months of 2022. The majority of these credits, 99.1 percent, were paid to CTs committed in real time either without or outside of a day-ahead schedule.[17] Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal. Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

PJM's position on the payment of uplift is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units should follow their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving balancing operating reserve credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Balancing operating reserve credits to generators increased by 16.8 percent in the first nine months of 2022 compared to the first nine months of 2021. PJM's increased need to run CTs resulted in increased balancing operating reserve credits during the first nine months of 2022. This increase concealed offsetting regional differences. Balancing operating reserve credits paid to units in the COMED zone decreased by 34.2 percent but credits paid to units in the DOM zone increased by 80.2 percent.

Table 4-6 shows monthly day-ahead and real-time generation by combustion turbines. In the first nine months of 2022, generation by combustion turbines was 7.9 percent higher in the real-time energy market than in the day-ahead energy market, although this varied by month. Table 4-6 shows that only 1.1 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 27.2 percent of generation from combustion turbines in the real-time market was uneconomic and required $97.9 million in BOR

17 Operating outside of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

credits. The relatively low level of uneconomic real-time generation resulted in reduced BOR credits during the first nine months of 2022.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: January through September, 2022

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Ratio of Day-Ahead to Real-Time Generation
Jan	1,754	0.9%	$0.0	1,056	23.4%	$9.2	1.7
Feb	561	3.0%	$0.0	361	19.6%	$2.2	1.6
Mar	254	2.2%	$0.0	306	52.3%	$4.9	0.8
Apr	416	2.2%	$0.0	738	39.7%	$11.0	0.6
May	776	1.0%	$0.1	1,031	30.3%	$8.8	0.8
Jun	1,563	1.6%	$0.2	1,685	22.2%	$11.1	0.9
Jul	2,187	1.0%	$0.0	2,467	24.6%	$18.0	0.9
Aug	1,776	0.8%	$0.1	2,381	26.5%	$23.2	0.7
Sep	1,126	0.4%	$0.0	1,288	29.2%	$9.3	0.9
Total (Jan - Sep)	10,414	1.1%	$0.6	11,312	27.2%	$97.9	0.9

Balancing operating reserve credits to generators in the first nine months of 2022 were $97.9 million, of which $97.1 million, or 85.6 percent of the $113.4 million in total balancing generator credits, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-7).

Table 4-7 shows real-time generation by combustion turbines by day-ahead commitment status in the first nine months of 2022 and 2021. In the first nine months of 2022, 64.7 percent of real-time CT generation was from CTs that operated on a day-ahead schedule.

In the first nine months of 2022, real-time CT generation operating consistent with their day-ahead schedule decreased compared to the first nine months of 2021 and this shift was one of many contributing factor to the increase of BOR. CTs that operate on a day-ahead schedule tend to receive lower BOR credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. Day-ahead LMPs support committing the units because the day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, amounting to greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: January 2021 through September 2022

		Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month-Year		Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
2021	Jan 2021	389	54.0%	44.4%	$0.1	331	46.0%	71.2%	$4.4
	Feb 2021	457	60.3%	43.8%	$0.2	301	39.7%	72.8%	$9.7
	Mar 2021	755	74.5%	35.6%	$0.1	258	25.5%	63.8%	$4.4
	Apr 2021	1,458	65.7%	28.4%	$0.1	760	34.3%	74.4%	$15.9
	May 2021	886	70.8%	32.6%	$0.0	365	29.2%	58.9%	$4.9
	Jun 2021	1,718	65.8%	28.7%	$0.2	891	34.2%	50.5%	$12.1
	Jul 2021	2,391	69.1%	24.5%	$0.3	1,070	30.9%	51.8%	$16.5
	Aug 2021	2,880	69.2%	22.9%	$0.3	1,284	30.8%	50.4%	$17.9
	Sep 2021	1,032	74.5%	20.5%	$0.1	353	25.5%	27.6%	$3.4
	Oct 2021	1,283	65.3%	24.2%	$0.2	683	34.7%	37.9%	$10.8
	Nov 2021	1,259	62.4%	26.3%	$0.1	759	37.6%	46.2%	$12.9
	Dec 2021	1,099	84.2%	32.6%	$0.0	207	15.8%	46.4%	$3.9
	Total 2021 (Jan - Sep)	11,967	68.1%	27.5%	$1.3	5,614	31.9%	56.1%	$89.2
	Total 2021	15,608	68.2%	27.5%	$1.7	7,262	31.8%	53.1%	$116.8
2022	Jan 2022	840	79.5%	15.4%	$0.1	217	20.5%	54.6%	$9.1
	Feb 2022	297	82.3%	12.7%	$0.1	64	17.7%	51.8%	$2.2
	Mar 2022	126	41.1%	33.8%	$0.1	180	58.9%	65.2%	$4.9
	Apr 2022	281	38.1%	25.7%	$0.1	457	61.9%	48.3%	$10.9
	May 2022	551	53.4%	26.0%	$0.0	480	46.6%	35.2%	$8.8
	Jun 2022	1,139	67.6%	18.8%	$0.4	545	32.4%	29.5%	$10.7
	Jul 2022	1,694	68.7%	20.7%	$0.1	772	31.3%	33.2%	$17.9
	Aug 2022	1,506	63.2%	20.2%	$0.1	876	36.8%	37.3%	$23.2
	Sep 2022	880	68.3%	25.0%	$0.0	408	31.7%	38.3%	$9.3
	Total (Jan - Sep)	7,313	64.7%	20.7%	$0.8	3,999	35.3%	39.0%	$97.1

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[18] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

18 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

Table 4-8 shows monthly day-ahead and real-time LOC credits in the first nine months of 2021 and 2022. In the first nine months of 2022, LOC credits increased by $7.8 million or 44.7 percent compared to the first nine months of 2021, comprised of a $4.1 million increase in day-ahead LOC and a $3.8 million increase in real-time LOC.

In the first nine months of 2022, wind units received $0.6 million of real-time LOC, up by $0.4 million compared to the first nine months of 2021. Wind units are not required to procure CIRs equal to the maximum facility output, but are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should be based on the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs).

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2021 through September 2022

	2021			2022		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.4	$0.0	$0.4	$3.3	$0.4	$3.7
Feb	$0.5	$0.0	$0.6	$1.4	$0.4	$1.8
Mar	$3.5	$0.0	$3.5	$0.5	$0.0	$0.5
Apr	$0.6	$0.0	$0.6	$0.7	$0.6	$1.3
May	$2.8	$0.1	$2.9	$0.9	$0.1	$1.0
Jun	$3.0	$0.1	$3.1	$5.1	$0.5	$5.6
Jul	$1.8	$0.1	$1.8	$4.7	$0.1	$4.8
Aug	$1.5	$0.1	$1.6	$2.5	$2.5	$5.0
Sep	$2.5	$0.5	$3.0	$1.5	$0.1	$1.7
Oct	$2.2	$0.2	$2.3			
Nov	$6.7	$0.5	$7.2			
Dec	$3.2	$0.0	$3.2			
Total (Jan - Sep)	$16.6	$0.9	$17.5	$20.7	$4.7	$25.4
Share (Jan - Sep)	94.6%	5.4%	100.0%	81.5%	18.5%	100.0%
Total	$28.6	$1.6	$30.2	$20.7	$4.7	$25.4
Share	94.7%	5.3%	100.0%	81.5%	18.5%	100.0%

Table 4-9 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and day-ahead generation receiving LOC credits. In the first nine months of 2022, 8.4 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 2.4 percentage points higher than in the first nine months of 2021. In the first nine months of 2022, day-ahead generation by combustion turbines decreased by 29.6 percent, day-ahead generation not requested in real time decreased by 1.5 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased by 16.4 percent, compared to the same time period in 2021. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2021 through September 2022

	2021			2022		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	1,293	69	17	2,262	306	101
Feb	1,203	53	12	753	110	38
Mar	1,355	64	16	448	60	13
Apr	2,007	62	15	675	54	18
May	1,556	213	55	1,069	101	20
Jun	2,634	223	76	1,882	138	44
Jul	3,251	149	46	2,603	154	57
Aug	3,856	162	32	2,173	88	43
Sep	1,661	130	46	1,388	97	32
Oct	1,982	140	46			
Nov	2,931	373	142			
Dec	1,980	159	61			
Total (Jan - Sep)	18,815	1,124	315	13,253	1,108	367
Share (Jan - Sep)	100.0%	6.0%	1.7%	100.0%	8.4%	2.8%
Total	25,707	1,795	565	13,253	1,108	367
Share	100.0%	7.0%	2.2%	100.0%	8.4%	2.8%

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-10 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[19] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[20]

Table 4-10 Dispatch status, commitment status and uplift eligibility[21]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

Table 4-11 shows day-ahead and real-time generation by commitment and dispatch status.

Table 4-11 Day-ahead and real-time generation by offer status and eligibility to set LMP (GWh): January through September, 2022

	Self Scheduled			Pool Scheduled						
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	58,113	127,005	160,466	133,998	141,250	17,507	638,339	292,755	345,585	192,111
Share of Day-Ahead	9.1%	19.9%	25.1%	21.0%	22.1%	2.7%	100.0%	45.9%	54.1%	30.1%
Real-Time Generation	51,983	123,631	158,472	128,469	155,177	19,846	637,577	303,492	334,086	180,452
Share of Real-Time	8.2%	19.4%	24.9%	20.1%	24.3%	3.1%	100.0%	47.6%	52.4%	28.3%

19 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
20 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.
21 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

Economic and Noneconomic Generation[22]

Economic generation includes units scheduled day ahead by PJM, or that produce energy in real time, at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units scheduled day ahead by PJM, or that produce energy in real time, at an incremental offer greater than the LMP at the unit's bus.

Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load and startup cost. A unit could be noneconomic for multiple hours and not receive operating reserve credits when the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits, which are defined by PJM as pool scheduled and dispatchable units. In the first nine months of 2022, 89.0 percent of the day-ahead generation MWh eligible for operating reserve credits was economic and 64.8 percent of the real-time generation MWh eligible for operating reserve credits was economic. A unit's generation MWh may be noneconomic for a portion of their daily generation and economic for the rest.

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the entire day or segment. Table 4-12 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2022, 0.8 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.4 percent of the real-time generation eligible for operating reserve credits received credits.

22 The analysis of economic and noneconomic generation is based on units' incremental offers and does not include no load or startup costs.

Table 4-12 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September, 2022

	Energy Market	
Generation	Day-Ahead	Real-Time
Economic Generation	260,667	163,619
Noneconomic Generation	32,078	88,863
Total Eligible Generation	292,745	252,482
Economic Generation Percent	89.0%	64.8%
Noneconomic Generation Percent	11.0%	35.2%
Generation Receiving Operating Reserve Credits	2,306	3,482
Generation Receiving Operating Reserve Credits Percent	0.8%	1.4%

Uplift Resettlement

Some units have been 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. The MMU has requested that PJM correctly resettle the uplift payments in these cases. Since 2018, the cumulative resettlement requests total $15.1 million, of which PJM has agreed and resettled 9.7 percent, and 67.4 percent remain pending. The remaining 22.9 percent occurred prior to October 2020 and would now require a directive from FERC for them to be resettled.[23] PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in

23 OATT § 10.4.

particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[24]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 26.4 percent of total energy uplift credits in the first nine months of 2022, compared to 13.1 percent in the same time period in 2021. In the first nine months of 2022, 275 units received 90 percent of all energy uplift credits, compared to 263 units in the same time period in 2021.

Figure 4-1 Cumulative share of energy uplift credits by unit: January through September, 2021 and 2022

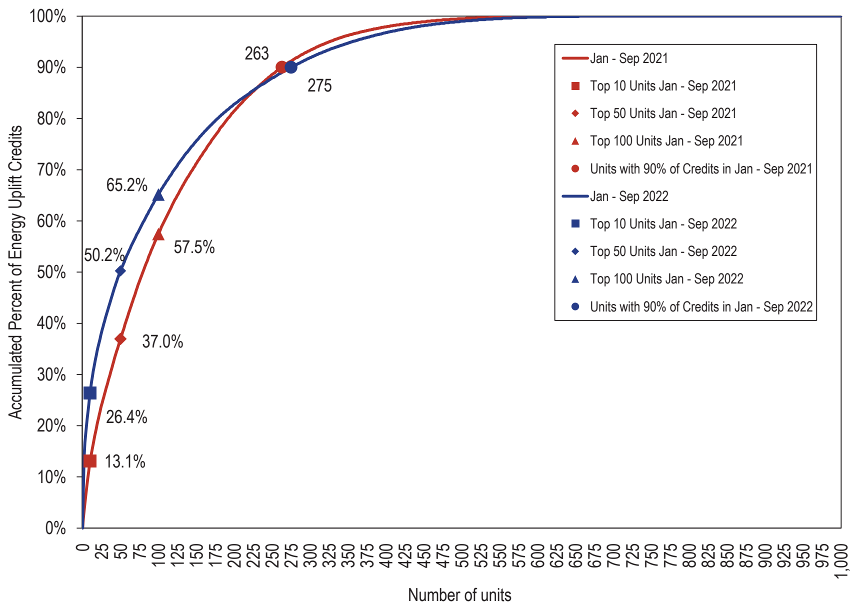


Table 4-13 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first nine months of 2021 and 2022.

Table 4-13 Top 10 units and organizations energy uplift credits: January through September, 2022

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$32.9	93.3%	$35.0	99.3%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$19.4	17.1%	$83.4	73.5%
	Local Constraints Control	$1.1	93.1%	$1.2	100.0%
	Lost Opportunity Cost	$5.4	21.4%	$18.4	72.4%
	Dispatch Differential Lost Opportunity Cost	$0.90	24.9%	$2.5	69.9%
Reactive Services		$1.2	99.8%	$1.2	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	40.1%	$0.3	89.6%
Total		$47.7	26.4%	$136.4	75.6%

In the first nine months of 2022, concentration in all energy uplift credit categories was high.[25] [26] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category.[27] Table 4-14 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8770, for balancing operating reserve credits to generators was 2372, for lost opportunity cost credits was 4992 and for reactive services credits was 3328. All of these HHI values are characterized as highly concentrated.

24 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits incurred on and after July 1, 2019 on September 10, 2019.

25 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

26 Table 4-17 excludes local constraint control categories.

27 Concentration is measured using the entity (or entities) to which the uplift credit is paid.

Table 4-14 Daily energy uplift credits HHI: January through September, 2022

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8770	2138	10000	100.0%	84.1%
	Imports	10000	10000	10000	100.0%	99.4%
	Load Response	10000	10000	10000	100.0%	99.6%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	2372	776	10000	100.0%	14.6%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	4992	1276	10000	100.0%	16.1%
	Dispatch Differential Lost Opportunity Cost	3328	643	10000	100.0%	20.0%
Reactive Services		9618	5428	10000	100.0%	41.1%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9595	4457	10000	100.0%	20.5%
Total		3328	643	10000	99.7%	19.5%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-15 through Table 4-18 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits. The top 10 units receiving uplift credits received 24.6 percent of all credits, with the top recipient receiving 7.7 percent. The top 10 units receiving day-ahead operating reserves received 93.3 percent. The top 10 recipients of balancing operating reserves received 17.1 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 21.4 percent of total lost opportunity cost credits.

Table 4-15 Top 10 recipients of total uplift: January through September, 2022

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$13,934,842	7.7%
2	BC BRANDON SHORES 1 F	BGE	$11,092,892	6.1%
3	PL BRUNNER ISLAND 3 F	PPL	$5,042,148	2.8%
4	VP MARSHRUN 2 CT	DOM	$3,020,814	1.7%
5	VP MARSHRUN 3 CT	DOM	$2,884,168	1.6%
6	VP MARSHRUN 1 CT	DOM	$2,683,083	1.5%
7	VP LOUISA 5 CT	DOM	$2,359,900	1.3%
8	VP FOUR RIVERS 1 CT	DOM	$2,329,071	1.3%
9	PEP CHALKPOINT 4 F	PEPCO	$2,177,659	1.2%
10	PEP CHALKPOINT 3 F	PEPCO	$2,131,415	1.2%
Total of Top 10			$47,655,993	26.4%
Total Uplift Credits			$180,494,813	100.0%

Table 4-16 Top 10 recipients of day-ahead generation credits: January through September, 2022

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$12,562,218	35.6%
2	BC BRANDON SHORES 1 F	BGE	$9,757,613	27.7%
3	PL BRUNNER ISLAND 3 F	PPL	$3,987,464	11.3%
4	BC WAGNER 4 F	BGE	$1,581,996	4.5%
5	PEP CHALKPOINT 4 F	PEPCO	$1,544,627	4.4%
6	PEP CHALKPOINT 3 F	PEPCO	$1,019,611	2.9%
7	PL BRUNNER ISLAND 2 F	PPL	$792,872	2.2%
8	VP YORKTOWN 3 F	DOM	$699,950	2.0%
9	BC WAGNER 1 F	BGE	$572,485	1.6%
10	PEP MORGANTOWN 2 F	PEPCO	$391,168	1.1%
Total of Top 10			$32,910,003	93.3%
Total day-ahead operating reserve credits			$35,283,549	100.0%

Table 4-17 Top 10 recipients of balancing operating reserve credits: January through September, 2022

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	VP MARSHRUN 2 CT	DOM	$2,766,483	2.4%
2	VP MARSHRUN 3 CT	DOM	$2,758,024	2.4%
3	VP MARSHRUN 1 CT	DOM	$2,589,240	2.3%
4	VP LOUISA 5 CT	DOM	$2,025,555	1.8%
5	VP FOUR RIVERS 1 CT	DOM	$1,803,322	1.6%
6	VP DOSWELL 3 CT	DOM	$1,703,970	1.5%
7	VP DOSWELL 2 CT	DOM	$1,573,020	1.4%
8	VP REMINGTON 3 CT	DOM	$1,540,477	1.4%
9	AEP ROBERT P MONE 2 CT	AEP	$1,324,999	1.2%
10	AEP ROBERT P MONE 3 CT	AEP	$1,274,783	1.1%
Total of Top 10			$19,359,873	17.1%
Total balancing operating reserve credits			$113,437,638	100.0%

Table 4-18 Top 10 recipients of lost opportunity cost credits: January through September, 2022

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	DAY DARBY 3 CT	AEP	$612,220	2.4%
2	DAY DARBY 1 CT	AEP	$610,020	2.4%
3	DAY DARBY 2 CT	AEP	$609,754	2.4%
4	DAY DARBY 4 CT	AEP	$553,460	2.2%
5	DAY DARBY 5 CT	AEP	$549,172	2.2%
6	DAY DARBY 6 CT	AEP	$540,156	2.1%
7	VP FOUR RIVERS 1 CT	DOM	$515,029	2.0%
8	DPL DEMEC - CLAYTON 2 CT	DPL	$502,666	2.0%
9	VP REMINGTON 1 CT	DOM	$480,079	1.9%
10	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	DPL	$451,230	1.8%
Total of Top 10			$5,423,786	21.4%
Total lost opportunity cost credits			$25,354,036	100.0%

Table 4-19 Top 10 recipients of dispatch differential lost opportunity cost credits: January through September, 2022

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credit	Share of Dispatch Differential Lost Opportunity Cost Credits
1	PL HOLTWOOD 19	PPL	$215,334	5.9%
2	VP PANDA STONEWALL 1 CC	DOM	$100,976	2.8%
3	ME BIRDSBORO 1 CC	MEC	$99,718	2.8%
4	AP LKLYN 1-4 H	AP	$90,744	2.5%
5	PL HUMMEL STATION 1 CC	PPL	$80,796	2.2%
6	PL SAFEHARBOR 4 H	PPL	$79,811	2.2%
7	PL SAFEHARBOR 12 H	PPL	$70,913	2.0%
8	PL SAFEHARBOR 9 H	PPL	$57,629	1.6%
9	PL SAFEHARBOR 8 H	PPL	$54,657	1.5%
10	PL HOLTWOOD 2	PPL	$51,486	1.4%
Total of Top 10			$902,064	24.9%
Total dispatch differential lost opportunity cost credits			$3,622,999	14.3%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-20 and Table 4-21 show the categories of credits and charges and their relationship. These tables show how the charges are allocated. The dispatch differential lost opportunity cost credit is a new balancing credit that was introduced during the implementation of fast start pricing on September 1, 2021. The new credit is charged and allocated to PJM members in proportion to their real-time load and exports for generator credits provided for reliability.

Table 4-20 Day-ahead and balancing operating reserve credits and charges

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

Table 4-21 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Charges Results

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 $131.3 million to $180.5 million.

Table 4-22 shows total energy uplift charges by category in the first nine months of 2021 and 2022.[28] The increase of $49.4 million is comprised of a $24.5 million increase in day-ahead operating reserve charges, a $24.2 million decrease in balancing operating reserve charges, a $0.5 million increase in reactive service charges, and $0.1 million increase in black start services charges.

Table 4-22 Total energy uplift charges by category: January through September, 2022[29]

Category	(Jan - Sep) 2021 Charges (Millions)	(Jan - Sep) 2022 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$10.8	$35.3	$24.5	227.6%
Balancing Operating Reserves	$119.4	$143.6	$24.2	20.3%
Reactive Services	$0.7	$1.2	$0.5	66.0%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.2	$0.3	$0.1	71.4%
Total	$131.1	$180.5	$49.4	37.7%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	(0.1%)	(21.8%)

28 Table 4-22 includes all categories of charges as defined in Table 4-20 and Table 4-21 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on October 13, 2022.

29 In Table 4-22, 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.

Table 4-23 compares monthly energy uplift charges by category for the first nine months of 2021 and 2022.

Table 4-23 Monthly energy uplift charges: January 2021 through September 2022

	2021 Charges (Millions)						2022 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2	$0.7	$14.6	$0.0	$0.0	$0.0	$15.3
Feb	$0.9	$13.7	$0.1	$0.0	$0.0	$14.6	$0.5	$5.1	$0.0	$0.0	$0.1	$5.6
Mar	$2.8	$8.5	$0.0	$0.0	$0.1	$11.4	$0.5	$7.0	$0.2	$0.0	$0.0	$7.8
Apr	$0.8	$17.0	$0.0	$0.0	$0.0	$17.8	$0.6	$13.4	$0.0	$0.0	$0.1	$14.1
May	$0.6	$8.7	$0.0	$0.0	$0.0	$9.3	$2.3	$12.1	$0.8	$0.0	$0.1	$15.3
Jun	$1.3	$16.5	$0.0	$0.0	$0.0	$17.8	$4.1	$20.0	$0.0	$0.0	$0.0	$24.2
Jul	$0.6	$19.7	$0.0	$0.0	$0.0	$20.3	$11.0	$25.7	$0.0	$0.0	$0.0	$36.7
Aug	$1.1	$21.2	$0.0	$0.0	$0.0	$22.3	$8.3	$32.2	$0.2	$0.0	$0.0	$40.7
Sep	$1.9	$7.3	$0.0	$0.0	$0.0	$9.2	$7.2	$13.5	$0.0	$0.0	$0.0	$20.7
Oct	$0.4	$14.2	$0.0	$0.0	$0.1	$14.7						
Nov	$0.8	$21.6	$0.2	$0.0	$0.0	$22.6						
Dec	$1.6	$8.2	$0.0	$0.0	$0.0	$9.9						
Total (Jan - Sep)	$10.8	$119.4	$0.7	$0.0	$0.2	$131.1	$35.3	$143.6	$1.2	$0.0	$0.3	$180.5
Share (Jan - Sep)	8.2%	91.1%	0.6%	0.0%	0.2%	100.0%	19.5%	79.6%	0.7%	0.0%	0.2%	100.0%
Total	$13.7	$163.4	$0.9	$0.0	$0.3	$178.3	$35.3	$143.6	$1.2	$0.0	$0.3	$180.5
Share	7.7%	91.6%	0.5%	0.0%	0.2%	100.0%	19.5%	79.6%	0.7%	0.0%	0.2%	100.0%

Table 4-24 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges include payments for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[30] [31] Day-ahead operating reserve charges increased by $24.5 million or 227.6 percent in the first nine months of 2022 compared to 2021.

Table 4-24 Day-ahead operating reserve charges: January through September, 2021 and 2022

Type	(Jan - Sep) 2021 Charges (Millions)	(Jan - Sep) 2022 Charges (Millions)	Change (Millions)	(Jan - Sep) 2021 Share	(Jan - Sep) 2022 Share
Day-Ahead Operating Reserve Charges	$10.8	$35.3	$24.5	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$10.8	$35.3	$24.5	100.0%	100.0%

Table 4-25 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $24.2 million or 20.3 percent in the first nine months of 2022 compared to 2021.

30 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.
31 See the *2022 Quarterly State of the Market Report for PJM: January through September*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-25 Balancing operating reserve charges: January through September, 2021 and 2022

Type	(Jan - Sep) 2021 Charges (Millions)	(Jan - Sep) 2022 Charges (Millions)	Change (Millions)	(Jan - Sep) 2021 Share	(Jan - Sep) 2022 Share
Balancing Operating Reserve Reliability Charges	$49.1	$50.9	$1.8	41.1%	35.4%
Balancing Operating Reserve Deviation Charges	$65.6	$91.5	$25.9	55.0%	63.7%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$4.7	$1.2	($3.5)	3.9%	0.9%
Total	$119.4	$143.6	$24.2	100.0%	100.0%

Table 4-26 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are the sum of: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In the first nine months of 2022, energy lost opportunity cost deviation charges decreased by $7.8 million or 44.8 percent, and make whole deviation charges decreased by $18.1 million or 37.5 percent compared to 2021.

Table 4-26 Balancing operating reserve deviation charges: January through September, 2021 and 2022

Charge Attributable To	(Jan - Sep) 2021 Charges (Millions)	(Jan - Sep) 2022 Charges (Millions)	Change (Millions)	(Jan - Sep) 2021 Share	(Jan - Sep) 2022 Share
Make Whole Payments to Generators and Imports	$48.1	$66.2	$18.1	73.3%	72.3%
Energy Lost Opportunity Cost	$17.5	$25.4	$7.8	26.7%	27.7%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$65.6	$91.5	$25.9	100.0%	100.0%

Table 4-27 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $0.5 million or 66.0 percent in the first nine months of 2022, compared to the first nine months of 2021.

Table 4-27 Additional energy uplift charges: January through September, 2021 and 2022

Type	(Jan - Sep) 2021 Charges (Millions)	(Jan - Sep) 2022 Charges (Millions)	Change (Millions)	(Jan - Sep) 2021 Share	(Jan - Sep) 2022 Share
Reactive Services Charges	$0.7	$1.2	$0.5	78.4%	77.8%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.2	$0.3	$0.1	21.6%	22.2%
Total	$0.9	$1.6	$0.6	100.0%	100.0%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates ten separate rates: a day-ahead operating reserve rate, a reliability rate for each region (RTO, East, or West), a deviation rate for each region, a lost opportunity cost rate, a canceled resources rate, and a dispatch differential lost opportunity cost rate.

Table 4-28 illustrates the composition of charges and the transactions included in the charge calculation. For example, balancing operating reserve charges for deviations are calculated by adding the RTO deviation rate, the regional deviation rates, the LOC rate, and the canceled resources rate. For example, the INCs are responsible for paying the RTO deviation rate, the regional deviation rate, the LOC rate, and the canceled resources rate.[32]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2021 and the first nine months of 2022. The average rate during the first nine months of 2022 was $0.050 per MWh, $0.034 per MWh higher than the average in the same time period in 2021. The highest rate during the first nine months of 2022 occurred on August 1 and the rate reached $0.354 per MWh, $0.226 per MWh higher than the $0.128 per MWh reached in in the first nine months of 2021, on May 4. Figure 4-2 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in the first nine months of 2021 or 2022.

Table 4-28 Composition of charges

		Transaction / Resource Type								
Charge	Rate	Load	Generation	Imports[1]	Exports[1]	Wheels	Economic DR	INCs	DECs	UTCs
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X				X	X
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X					
	Regional (East or West) Reliability Rate	X			X					
Balancing Operating Reserves for Deviations[2]	RTO Deviation Rate	X	X	X	X		X	X	X	X
	Regional (East or West) Deviation Rate	X	X	X	X		X	X	X	X
	LOC Rate	X	X	X	X		X	X	X	
	Canceled Resources Rate	X	X	X	X		X	X	X	
Reactive Services	Implicit Rates	X								
Black Start Services	Implicit Rates	X[3]		X[4]	X[4]	X[4]				
Synchronous Condensing	Implicit Rate	X			X					

1 Dynamic scheduled transactions are exempt from operating reserve charges.
2 Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.
3 Load is charged black start services based on their zonal peak load contribution.
4 Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

32 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO Region since these three charges are allocated following the same rules.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): January 2021 through September 2022

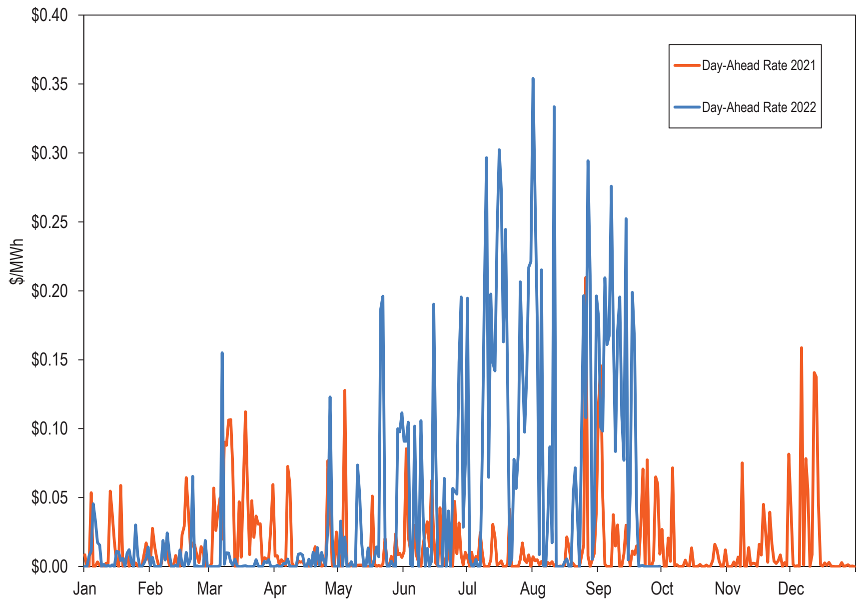


Figure 4-3 shows the RTO and the regional reliability rates for 2021 and the first nine months of 2022. The average RTO reliability rate in the first nine months of 2022 decreased to $0.070 per MWh from $0.073 in 2021. The highest RTO reliability rate in the first nine months of 2022 occurred on January 27 when the rate reached $0.982 per MWh, $0.320 per MWh higher than the $0.662 per MWh rate reached in the first nine months of 2021, on June 29.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): January 2021 through September 2022

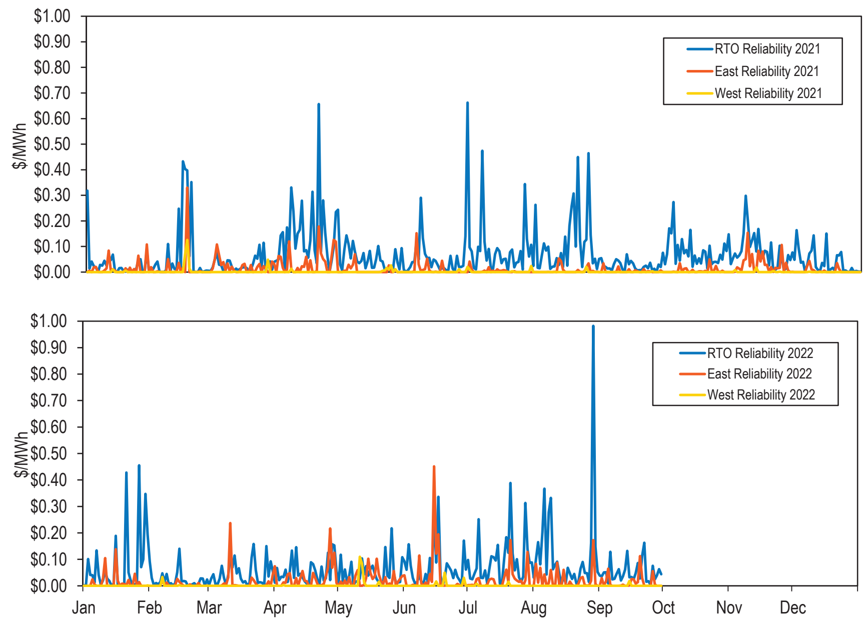


Figure 4-4 shows the RTO and regional deviation rates for 2021 and the first nine months of 2022. The average RTO deviation rate in the first nine months of 2022 was $0.238 per MWh. The highest daily rate during the first nine months of 2022 occurred on July 19, when the RTO deviation rate reached $2.043 per MWh, $0.333 per MWh higher than the $1.710 per MWh rate reached in the first nine months of 2021, on April 19.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): January 2021 through September 2022

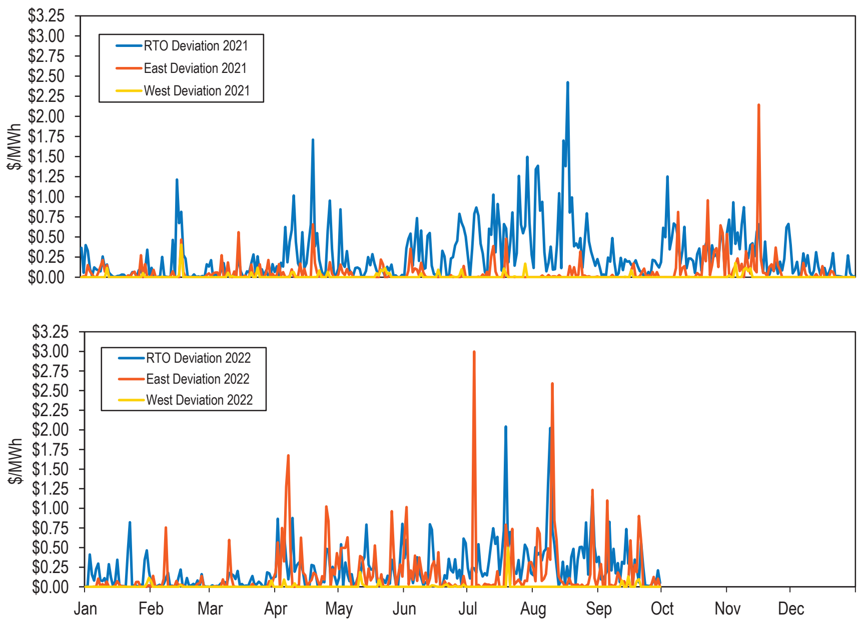


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2021 and the first nine months of 2022. The average lost opportunity cost rate in the first nine months of 2021 was $0.106 per MWh. The highest lost opportunity cost rate in the first nine months of 2022 occurred on June 13, when it reached $3.810 per MWh, $2.613 per MWh more than the $1.197 per MWh rate reached in the first nine months of 2021, on May 25.

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2021 through September 2022

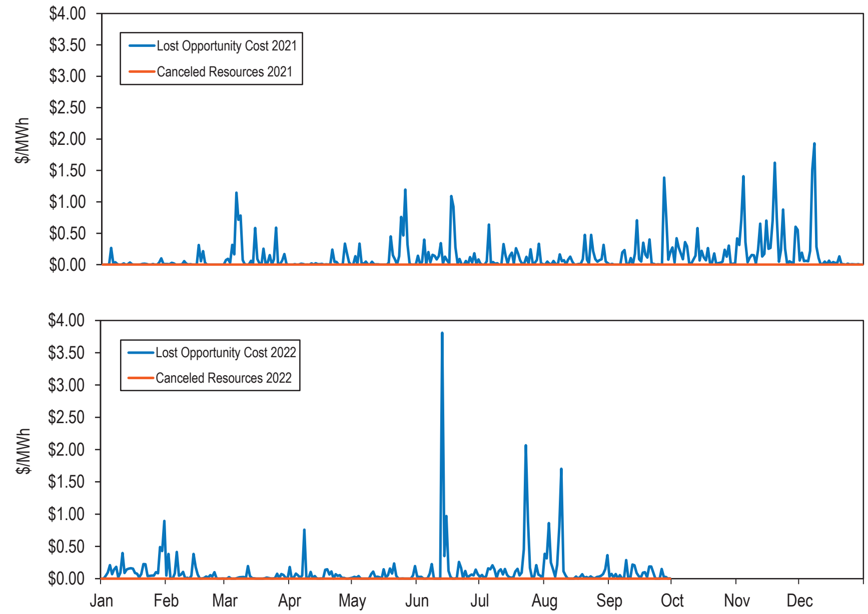


Table 4-29 shows the average rates for each region in each category for the first nine months of 2021 and 2022.

Table 4-29 Operating reserve rates ($/MWh): January through September, 2021 and 2022

Rate	(Jan - Sep) 2021 ($/MWh)	(Jan - Sep) 2022 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.016	0.050	0.034	209.9%
Day-Ahead with Unallocated Congestion	0.016	0.050	0.034	209.9%
RTO Reliability	0.073	0.070	(0.002)	(3.3%)
East Reliability	0.013	0.021	0.008	65.7%
West Reliability	0.002	0.002	(0.000)	(17.7%)
RTO Deviation	0.267	0.238	(0.029)	(10.8%)
East Deviation	0.042	0.157	0.115	271.1%
West Deviation	0.009	0.007	(0.002)	(23.8%)
Lost Opportunity Cost	0.106	0.120	0.014	13.0%
Canceled Resources	0.000	0.000	NA	N/A
Dispatch Differential Lost Opportunity Cost	NA	0.006	NA	N/A

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments if they are committed out of merit to provide reactive, or incur opportunity costs associated with reduced energy output. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[33] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-30 shows the reactive services rates associated with local voltage support in the first nine months of 2021 and 2022. Table 4-30 shows that in 2022 only five zones incurred reactive services charges.

33 See *2021 State of the Market Report for PJM*, Volume 2; Section 10: Ancillary Service Markets.

Table 4-30 Local voltage support rates: January through September, 2021 and 2022

Control Zone	(Jan - Sep) 2021 ($/MWh)	(Jan - Sep) 2022 ($/MWh)	Difference ($/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	(0.000)	(100.0%)
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.011	0.011	NA
COMED	0.000	0.000	0.000	0.0%
DAY	0.000	0.000	0.000	0.0%
DUKE	0.000	0.000	0.000	0.0%
DUQ	0.000	0.000	0.000	0.0%
DOM	0.000	0.002	0.002	NA
DPL	0.000	0.016	0.016	28,504.5%
EKPC	0.000	0.000	(0.000)	(100.0%)
JCPLC	0.000	0.000	0.000	0.0%
MEC	0.001	0.001	0.001	132.4%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PE	0.000	0.000	0.000	0.0%
PEPCO	0.000	0.023	0.023	NA
PPL	0.023	0.000	(0.023)	(100.0%)
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

Geography of Charges and Credits

Table 4-31 shows the geography of charges and credits in the first nine months of 2022. Table 4-31 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the PPL Control Zone paid 4.7 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 5.8 percent of the corresponding credits. The PPL Control Zone received fewer operating reserve credits than operating reserve charges paid and had 3.2 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.5 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 16.8 percent of the corresponding credits. The BGE Control Zone received fewer operating reserve credits than operating reserve charges paid and had 44.8 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-31 also shows that 85.7 percent of all charges were allocated in control zones, 6.2 percent in hubs and aggregates and 8.0 percent in interfaces.

Table 4-31 Geography of regional charges and credits: January through September, 2022

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$2.4	$1.9	($0.5)	1.4%	1.1%	1.0%	0.0%
	AEP	$23.9	$26.1	$2.3	13.4%	14.7%	0.0%	4.2%
	APS	$6.9	$3.7	($3.2)	3.9%	2.1%	6.8%	0.0%
	ATSI	$10.0	$7.2	($2.8)	5.6%	4.0%	6.0%	0.0%
	BGE	$6.3	$29.9	$23.6	3.5%	16.8%	0.0%	43.6%
	COMED	$17.0	$15.4	($1.6)	9.6%	8.7%	3.4%	0.0%
	DAY	$3.1	$6.0	$2.9	1.7%	3.4%	0.0%	5.4%
	DUKE	$5.2	$2.9	($2.4)	2.9%	1.6%	5.0%	0.0%
	DUQ	$2.2	$0.1	($2.1)	1.3%	0.1%	4.5%	0.0%
	DOM	$23.4	$38.3	$14.9	13.2%	21.5%	0.0%	27.5%
	DPL	$4.2	$6.9	$2.7	2.4%	3.9%	0.0%	4.9%
	EKPC	$4.0	$5.8	$1.8	2.2%	3.3%	0.0%	3.4%
	External	$0.0	$3.6	$3.6	0.0%	2.0%	0.0%	6.6%
	JCPLC	$4.4	$1.5	($2.9)	2.5%	0.8%	6.2%	0.0%
	MEC	$3.6	$2.7	($0.9)	2.0%	1.5%	2.0%	0.0%
	OVEC	$0.8	$0.0	($0.7)	0.4%	0.0%	1.5%	0.0%
	PECO	$7.4	$1.5	($5.9)	4.2%	0.8%	12.5%	0.0%
	PE	$4.4	$4.1	($0.3)	2.5%	2.3%	0.5%	0.0%
	PEPCO	$5.7	$6.1	$0.5	3.2%	3.5%	0.0%	0.9%
	PPL	$8.3	$10.2	$1.9	4.7%	5.8%	0.0%	3.5%
	PSEG	$8.1	$3.8	($4.3)	4.6%	2.2%	9.1%	0.0%
	REC	$0.8	$0.0	($0.8)	0.4%	0.0%	1.6%	0.0%
	All Zones	$152.0	$177.7	$25.7	85.5%	100.0%	60.1%	100.0%
Hubs and Aggregates	AEP - Dayton	$2.0	$0.0	($2.0)	1.1%	0.0%	4.3%	0.0%
	Dominion	$1.6	$0.0	($1.6)	0.9%	0.0%	3.3%	0.0%
	Eastern	$0.9	$0.0	($0.9)	0.5%	0.0%	1.9%	0.0%
	New Jersey	$0.9	$0.0	($0.9)	0.5%	0.0%	2.0%	0.0%
	Ohio	$1.9	$0.0	($1.9)	1.1%	0.0%	4.1%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$3.9	$0.0	($3.9)	2.2%	0.0%	8.2%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$11.3	$0.0	($11.3)	6.3%	0.0%	23.9%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.7	$0.0	($0.7)	0.4%	0.0%	1.6%	0.0%
	IMO	$0.6	$0.0	($0.6)	0.3%	0.0%	1.3%	0.0%
	Linden	$0.4	$0.0	($0.4)	0.2%	0.0%	0.9%	0.0%
	MISO	$3.4	$0.0	($3.4)	1.9%	0.0%	7.2%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$0.6	$0.0	($0.6)	0.3%	0.0%	1.2%	0.0%
	NIPSCO	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	NYIS	$1.8	$0.0	($1.8)	1.0%	0.0%	3.8%	0.0%
	South Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South	$6.9	$0.0	($6.9)	3.9%	0.0%	14.6%	0.0%
	All Interfaces	$14.4	$0.0	($14.4)	8.1%	0.0%	16.0%	0.0%
	Total	$177.7	$177.7	$0.0	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[34] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-32 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first nine months of 2022, balancing operating reserve credits would have been $31.3 million or 27.6 percent lower if they were calculated on a daily 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 were calculated on a daily basis.

Table 4-32 Intraday segments and daily balancing operating reserve credits: January 2021 through September 2022

	2021 BOR Credits (Millions)			2022 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$4.8	$4.2	($0.6)	$10.2	$8.5	($1.8)
Feb	$10.6	$9.4	($1.2)	$3.2	$2.5	($0.7)
Mar	$5.0	$4.0	($1.0)	$5.3	$4.5	($0.8)
Apr	$16.4	$15.0	($1.3)	$11.9	$9.9	($1.9)
May	$5.8	$4.7	($1.1)	$10.6	$7.9	($2.7)
Jun	$13.0	$9.8	($3.2)	$13.8	$9.7	($4.1)
Jul	$17.8	$14.0	($3.8)	$20.3	$14.5	($5.8)
Aug	$19.6	$14.5	($5.1)	$26.6	$18.7	($8.0)
Sep	$4.2	$2.4	($1.8)	$11.5	$6.1	($5.4)
Oct	$11.6	$8.7	($2.9)			
Nov	$14.0	$9.9	($4.1)			
Dec	$4.9	$4.0	($0.9)			
Total (Jan - Sep)	$97.1	$77.9	($19.2)	$113.4	$82.2	($31.3)
Total	$127.5	$100.5	($27.0)	$113.4	$82.2	($31.3)

34 See PJM "Manual 28: Operating Reserve Accounting," Rev. 89 (Nov. 1, 2022).

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-33 shows the impact on day-ahead LOC credits to CTs that are committed DA but not RT. The table shows the LOC credits calculated in three ways: with the five minute settlement calculations implemented in April 2018; with hourly settlements prior to the change in April 2018; and with daily settlements. In the first nine months of 2022, LOC credits would have been $ 2.3 million or 11.3 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In the first nine months of 2022, LOC credits would have been $5.4 million or 26.0 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

Table 4-33 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through September, 2022

	2022 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$3.3	$2.7	($0.6)	$1.8	($1.5)
Feb	$1.4	$1.2	($0.2)	$1.0	($0.4)
Mar	$0.5	$0.4	($0.1)	$0.3	($0.2)
Apr	$0.7	$0.6	($0.2)	$0.4	($0.3)
May	$0.9	$0.6	($0.3)	$0.3	($0.6)
Jun	$5.1	$4.8	($0.3)	$4.6	($0.6)
Jul	$4.7	$4.3	($0.4)	$3.9	($0.7)
Aug	$2.5	$2.4	($0.1)	$2.1	($0.4)
Sep	$1.5	$1.3	($0.3)	$0.9	($0.6)
Total (Jan - Sep)	$20.7	$18.3	($2.3)	$15.3	($5.4)

Uplift Credits by Offer Type

Absent market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[35] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power. Offer capping is designed to set offers at competitive levels.

Table 4-34 shows the uplift credits paid to committed and dispatched units in the first nine months of 2022 by offer type. Units received $65.5 million or 57.8 percent of balancing operating reserve credits and $17.4 million or 49.3 percent of day-ahead operating reserve credits in the first nine months of 2022 using price-based offers. Units received $35.8 million or 31.6 percent of balancing operating reserves and $16.9 million or 47.8 percent of day-ahead operating reserves in the first nine months of 2022 using cost-based offers.

Table 4-34 Operating Reserve Credits by Offer Type: January through September, 2022

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total
Cost	$16.9	$35.8	$0.5	$0.2	$53.4
Price	$17.4	$65.5	$0.3	$0.0	$83.2
Price PLS	$1.0	$9.1	$0.0	$0.0	$10.1
Cost & Price	$0.0	$2.3	$0.0	$0.0	$2.3
Cost & PLS	$0.0	$0.6	$0.0	$0.0	$0.6
Price & PLS	$0.0	$0.1	$0.0	$0.0	$0.1
Total	$35.3	$113.4	$0.7	$0.3	$149.7
Share	23.6%	75.8%	0.5%	0.2%	100.0%

Table 4-35 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. Of all the day-ahead credits received during days with weather alerts, 14.6 percent went to units that were committed on price PLS schedules and 0.3 percent went to units committed on price schedules as flexible as PLS.

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

Table 4-35 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through September, 2022

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during Hot and Cold Weather Alerts
Committed on cost (cost capped)	$3,443,646	48.6%
Committed on price schedule as flexible as PLS	$23,411	0.3%
Committed on price schedule less flexible than PLS	$2,587,150	36.5%
Committed on price PLS	$1,034,588	14.6%
Total	$7,088,794	100.0%

Fast Start Pricing

The implementation of fast start pricing on September 1, 2021, included a new credit intended to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. With fast start pricing, cleared and dispatched MW are determined in the dispatch run, identical to the combined dispatch and pricing process prior to fast start, while LMPs are determined in the pricing run, which calculates prices based on the counterfactual assumption that the fast start resources are flexible and can back down to a low economic minimum MW. Fast start pricing creates a divergence between the pricing run LMP that signals a higher MW for some resources and the lower dispatch run MW to which PJM dispatches the resource based on its offer curve. The resources dispatched down would produce more MWh if they responded to the actual market LMP from the pricing run. The resulting dispatch differential lost opportunity cost credit is the revenue lost by the resource as a result of operating at the lower dispatch MW rather than the MW on its offer curve corresponding to the actual market LMP from the pricing run. Table 4-1 shows that the dispatch differential lost opportunity cost for the first nine months of 2022 was $3.6 million. Table 4-3 shows that 28.5 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 39.8 percent to combustion turbines. In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as they are directly counter to the logic of fast start pricing as well as to tariff rules.

The MMU recommends that PJM not make such payments and require refunds where it has already done so. This is part of the broader recommendation that PJM stop paying uplift to resources that do not follow dispatch.

A primary argument made by the proponents of fast start pricing is that it will reduce uplift to fast start units by raising LMP, and thus revenue, when they are operating. This reduction in uplift would be most likely to occur in balancing operating reserves payments. To the extent that fast start pricing increases day-ahead prices, it may also reduce Day-Ahead Operating Reserve payments. But fast start pricing also increases other uplift payments, especially the new dispatch differential lost opportunity cost payment. Day-ahead lost opportunity cost payments to fast start resources may also increase because real-time LMPs are higher than they would be without fast start pricing.

There is not enough data on the implementation of fast start pricing after one month to support clear conclusions about the separable impacts of fast start pricing on uplift.

Table 4-36 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $27.6 million in balancing operating reserve credits, or 24.4 percent of total balancing operating reserves. Fast start units received $6.4 million in day-ahead lost opportunity costs, or 30.9 percent of all lost opportunity costs. Fast start units received less than $0.1 million in day-ahead operating credits, or 0.1 percent of total day ahead operating reserve credits.

Table 4-36 Monthly Day-ahead operating reserves, balancing operating reserves, and day-ahead lost opportunity cost credits for fast start units: January through September, 2022

Month	Day-Ahead Operating Reserves (Millions)	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves (Millions)	Share of Monthly Balancing Operating Reserves	Day Ahead Lost Opportunity Cost Credits (Millions)	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.5%	$1.7	16.6%	$1.2	34.9%
Feb	$0.0	0.0%	$0.6	19.5%	$0.6	43.5%
Mar	$0.0	0.1%	$1.7	32.5%	$0.1	13.1%
Apr	$0.0	0.2%	$2.9	24.7%	$0.1	16.6%
May	$0.0	0.0%	$2.5	23.7%	$0.1	14.9%
Jun	$0.0	0.8%	$2.7	19.3%	$2.1	40.7%
Jul	$0.0	0.0%	$5.8	28.7%	$1.6	34.1%
Aug	$0.0	0.0%	$6.9	26.0%	$0.5	21.2%
Sep	$0.0	0.0%	$2.7	23.6%	$0.1	7.0%
Total (Jan - Sep)	$0.0	0.1%	$27.6	24.4%	$6.4	30.9%

Table 4-37 shows the day-ahead, balancing operating reserves, and day-ahead lost opportunity cost credits for combustion turbines by month.

Table 4-37 Day-ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: January through September, 2022

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves	Share of Monthly Day Ahead Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.5%	$1.6	15.9%	$1.0	28.6%
Feb	$0.0	0.0%	$0.0	0.0%	$0.6	42.3%
Mar	$0.0	0.1%	$0.6	10.6%	$0.1	11.8%
Apr	$0.0	0.2%	$2.8	23.9%	$0.1	14.1%
May	$0.0	1.4%	$2.4	22.8%	$0.1	13.6%
Jun	$0.0	0.0%	$2.6	18.9%	$2.1	40.2%
Jul	$0.0	0.0%	$5.8	28.4%	$1.5	32.6%
Aug	$0.0	0.0%	$6.8	25.5%	$0.5	18.9%
Sep	$0.0	0.0%	$2.6	22.7%	$0.1	6.1%
Total (Jan - Sep)	$0.0	0.1%	$25.4	22.4%	$6.2	30.0%

Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The only reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price. The first, daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. But in order for the PJM markets to be self sustaining, the net 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 and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources, with the current exception of the small amounts of intermittent and storage capacity, are required to offer into the capacity auctions. All LSEs must buy capacity equal to their peak load plus a reserve margin.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the 2023/2024 Base Residual Auction.

Table 5-1 The capacity market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive in the 2023/2024 BRA after the Commission order addressed the definition of the market seller

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

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

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. 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.[4] 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.[5]

4 176 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.
5 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and 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.[6] 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.[7] 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.[8] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[9] 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.[10]

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.[11] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources

6 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
7 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.
8 See 126 FERC ¶ 61,275 at P 86 (2009).
9 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
10 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
11 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.

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 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.[12] 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.[13] [14] [15]
- **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

12 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).

13 See OATT Attachment DD § 6.5.

14 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).

15 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).

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.

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.[16]
- **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.

Recommendations[17]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18] [19] (Priority: High. First reported 2013. Status: Not adopted.)
- 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.)[20]
- 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.[21] (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.)[22]

16 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.

17 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.

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

19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 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).

20 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).

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

22 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 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.)
- 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.)[23]
- 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.[24] [25] 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.)

23 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>.
24 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
25 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- 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 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.)[26]

26 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).

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.[27] (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.[28] (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

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

28 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).

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.)
- 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.)[29]
- 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.)[30]

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.)

29 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).

30 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).

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 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.)

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.[31] [32] 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.[33] [34] [35] 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

31 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).
32 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).
33 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47 (February 21, 2019) ("IMM MSOC Complaint").
34 176 FERC ¶ 61,137 (2021).
35 178 FERC ¶ 61,121 (2022).

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 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.[36] 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."[37] 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.[38] 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.[39] 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."[40] 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.[41] 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.[42] 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.[43] The logical circularity of the argument as

36 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.

37 See page 55 of CP Filing.

38 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.

39 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).

40 See page 43 of CP Filing.

41 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).

42 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).

43 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>.

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 CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[44] [45]

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.[46] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

44 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").
45 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.

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.[47] 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

46 174 FERC ¶ 61,212 ("March 18th Order") at 65.
47 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.

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 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.[48] [49] [50] [51] [52] [53] [54] [55] 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.[56] A majority of capacity investments in PJM were financed by market sources.[57] 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.

48 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).
49 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).
50 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).
51 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).
52 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).
53 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).
54 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).
55 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).
56 The calculated reserve margin for June 1, 2023, does not account for cleared buy bids that have not been used in replacement capacity transactions.
57 "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).

Table 5-2 RPM related MMU reports: January 2021 through September 30, 2022

Date	Name
January 29, 2021	Analysis of NJ Zero Emissions Credit(ZEC)Applications https://www.monitoringanalytics.com/reports/Reports/2021/IMM_Public_Report_Analysis_of_NJ_ZEC_Applications_20210129.pdf
February 19, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20210219.pdf
March 4, 2021	Next Steps in Capacity Market Design https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_Capacity_Market_Workshop_Session_2_Next_Steps_in_Capacity_Market_Design_20210304.pdf
March 5, 2021	IMM Comment re New Jersey FRR Docket No. EO20030203 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_EO20030203_20210305.pdf
March 22, 2021	IMM Comments re ELCC Docket No. ER21-278-001 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-278-001_20210322.pdf
March 31, 2021	IMM Answer re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_Nos_EL21-62_EL21-63_20210331.pdf
April 7, 2021	RPM Capacity Transfer Rights: Education https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_RPM_Capacity_Transfer_Rights_Education_20210407.pdf
April 12, 2021	IMM Commentsr re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_Nos_EL21-62_EL21-63_20210412.pdf
April 19, 2021	IMM Answer to P3 re MSOC Docket Nos. EL19-47-001, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20210419.pdf
April 26, 2021	IMM Comments re Modernizing Electricity Market Design Docket No. AD21-10 https://www.monitoringanalytics.com/filings/2021/IMM_Post_Technical_Conference_Comments_Docket_No_AD21-10_20210426.pdf
April 28, 2021	IMM Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Brief_Docket_No_EL19-47_et_al_20210428.pdf
April 29, 2021	IMM Answer to PJM re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Docket_No_ER21-278_20210429.pdf
May 18, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_RPM_Must_Offer_Obligations_20210518.pdf
May 19, 2021	IMM Answer to Motion re ELCC Docket No. EL19-100 and ER20-584 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Motion_Docket_No_EL19-100_20210519.pdf
May 25, 2021	IMM Comments re PJM Capacity Market CRF Docket No. ER21-1844 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1844_20210525.pdf
June 9, 2021	IMM Reply Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Reply_Brief_Docket_No_EL19-47_EL19-63_20210609.pdf
June 15, 2021	IMM Response to Exelon re 10 Year Report Case No. 9271 https://www.monitoringanalytics.com/filings/2021/IMM_Response_to_Exelon_MDPSC_Case_No_%209271_20210615.pdf
June 16, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MOPR_Matrix_Entries_20210616.pdf
June 22, 2021	IMM Comments re ELCC Docket No. ER21-2043 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_ER21-2043_20210622.pdf
June 25, 2021	IMM Answer to Replies re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_20210625.pdf
June 28, 2021	Data Submission Window Opening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2023-2024_BRA_20210628.pdf
June 30, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_CIFP_MOPR_MOPR_Matrix_Entries_20210630.pdf
August 11, 2021	EE Addback Issue https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_EE_Addback_Issue_20210811.pdf
August 11, 2021	EE Addback Issue Charge Revised https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_EE_Addback_Issue_Charge_Rev%2020210811.pdf
August 27, 2021	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_Quad_Review_Issues_20210827.pdf
September 2, 2021	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_20210902.pdf
September 13, 2021	Data Submission Window Reopening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023_2024_Base_Residual_Auction_20210913.pdf
September 17, 2021	IMM Informational Session on MSOC https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_MSOC_Net_ACR_%20Informational_Session_on_MSOC_20210917.pdf
September 22, 2021	IMM Answer to Comments re MOPR Docket No. ER21-2582 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Comments_Docket_No_ER21-2582_20210922.pdf
September 23, 2021	Market Seller Offer Cap (MSOC) Information https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_MSOC_ACR_Market_Seller_Offer_Cap_20210923.pdf
September 27, 2021	IMM MOPR Review: PA House Environmental Resources & Energy Committee https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_PA_House_E_and_E_MOPR_Review_20210927.pdf
September 28, 2021	Capacity Market Phase 2 Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_Capacity_Market_Workshop_20210928.pdf
September 29, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_BRA_Updated.pdf
September 30, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20210930.pdf
October 5, 2021	Data Submission Window Opening for the 2022/2023 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_20222023_Third_Incremental_Auction_20211005.pdf
October 6, 2021	Data Submission Window Opening for the 2022/2023 RPM Third Incremental Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_%2020222023_Third_Incremental_Auction_20211005-Updated.pdf
October 12, 2021	IMM Motion for Clarification re MSOC Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Motion_for_Clarification_Docket_No_EL19-47_et_al_20211012.pdf
October 20, 2021	IMM Answer to PJM re RGGI Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20211020.pdf
October 22, 2021	Capacity Market Phase 2 Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_RASTF_Capacity_Market_Workshop_202101022.pdf
October 22, 2021	IMM Comments re SOO Green Capacity Complaint Docket No. EL21-103 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_EL21-103_20211022.pdf
October 23, 2021	Unit Specific Net Revenue Calculation (Dispatchable Units) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenue_Calculation_2023_2024_Base_Residual_Auction_20211023.pdf
October 30, 2021	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Revised_20211030.pdf
November 1, 2021	IMM Comments and Market Power Analysis re PSEG-Arclight Transaction Docket No. EC21-128 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_EC21-128_20211101.pdf
November 5, 2021	Net Revenue Calculation Update 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Unit_Specific_Net_Revenue_Calculation_Dispatchable_Units_20232024_BRA_20211105.pdf
November 12, 2021	Net Revenue Calculation Update 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Unit_Specific_Review_Dispatchable_Units_Update_2023_2024_BRA_20211112.pdf

Table 5-2 RPM related MMU reports: January 2021 through September 30, 2022 (continued)

Date	Name
November 18, 2021	IMM Motion for Clarification or Waiver re MSOC Deadlines Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Motion_for_Clarification_or_Waiver_Docket_No_EL19-47_20211118.pdf
November 19, 2021	IMM Comments re ArcLight/PSEG Transaction Docket No. EC21-128 https://www.monitoringanalytics.com/filings/2021/IMM_Letter_Merger_Docket_No_EC21-128_20211119.pdf
November 23, 2021	Alternative MSOC Agreement Template https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Alternative_MSOC_Agreement_Template_20211123.docx
November 23, 2021	Alternative Market Seller Offer Caps for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Alternative_MSOC_2023-2024_Base_Residual_Auction_20211123.pdf
November 30, 2021	IMM Determinations Posted for the PJM 2022/2023 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2022-2023_Third_Incremental_Auction_20211130.pdf
December 1, 2021	IMM Answer to PJM re MSOC Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Answer_Docket_No_EL19-47_20211201.pdf
December 1, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_for_the_20232024_RPM_BRA_20211201.pdf
December 3, 2021	Data Submission Window Reopening- 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_%202023-2024_Base_Residual_Auction_Updated_20211203.pdf
December 29, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20211229.pdf
January 5, 2022	MSOC Issues https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_Issues_20220110.pdf
January 7, 2021	Reactive Power Compensation and the Capacity Market https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RPCTF_Reactive_Power_Compensation_20220107.pdf
January 27, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023-2024_Base_Residual_Auction_Updated_20220127.pdf
February 4, 2022	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_Base_Residual_Auction_Updated_20220204.pdf
February 11, 2022	2022 Quadrennial Review: IMM Proposals and Results https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_IMM_CONE_CT_CC_Study_20220211.pdf
February 22, 2022	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 25, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20220225.pdf
March 2, 2022	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Updated_20220302.pdf
March 7, 2022	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Updated_20220307.pdf
March 25, 2022	Quadrennial Review: VRR Curve https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_VRR_Curve_20220325.pdf
March 25, 2022	Quadrennial Review: IMM Gross and Net CONE Update https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_IMM_CONE_CT_CC_Proposals_and_Results_20220325.pdf
April 11, 2022	MSOC http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_20220411.pdf
April 20, 2022	IMM Comments re MSOC Show Cause Order Docket No. EL22-22 http://www.monitoringanalytics.com/filings/2022/IMM_Comments_Docket_No_EL22-22_et_al_20220420.pdf
April 22, 2022	IMM CONE Study Update http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_2022_Quad_Review_CONE_CT_CC_20220422.pdf
April 22, 2022	Impact of Brattle Proposed VRR Curves http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_2022_Quad_Review_Impact_of_Brattle_Proposed_VRR_Curves_20220422.pdf
May 4, 2022	IMM RASTF MSOC Presentation http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_20220504.pdf
May 23, 2022	IMM Brief of Intervenor for Petitioners re US Court of Appeals Third Circuit EPSA vs. FERC Docket Nos. 21-3205, et al http://www.monitoringanalytics.com/filings/2022/IMM_Brief_of_Intervenor_for_Petitioners_Docket_Nos_21-3205_et_al_20220523.pdf
May 26, 2022	Capacity Definition http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_Capacity_Definition_20220526.pdf
June 7, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 Delivery Year http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20220607.pdf
June 10, 2022	CPQR Simulation Approach http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_CPQR_Simulation_Approach_MSOC_20220610.pdf
June 21, 2022	Quadrennial Review Impact of VRR Shape Proposal http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quad_Review_Impact_of_VRR_Shape_Proposal_20220621.pdf
June 23, 2022	IMM MSOC Package Executive Summary http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_Package_Executive_Summary_20220620.pdf
July 8, 2022	Data Submission Window Opening for the 2024/2025 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_20242025_Base_Residual_Auction_20220708.pdf
July 13, 2022	Impact of VRR Shape Proposals http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_Impact_of_VRR_Shape_Proposals_20220713.pdf
August 24, 2022	Comparison of IMM Net CONE to PJM Net CONE http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_Comparison_IMM_Net_CONE_to_PJM_Net_CONE_20220824.pdf
September 7, 2022	Market Approach to Behind the Generator Load http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_Market_Approach_to_BGL_20220907.pdf
September 9, 2022	IMM Determinations Posted for the PJM 2024/2025 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2024-2025_Base_Residual_Auction_20220908.pdf
September 28, 2022	Estimated Impact of Reactive Offset on Capacity Market Results http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RCPTF_Estimated_Impact_of_Reactive_Offset_on_Capacity_Market_Results_20220928.pdf
September 30, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 and 2024/2025 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20220930.pdf
October 13, 2022	Market Approach to Behind the Generator Load (BGL) http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_Market_Approach_to_BGL_20221013.pdf
October 28, 2022	Analysis of the 2023/2024 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf

Installed Capacity

On January 1, 2022, RPM installed capacity was 186,117.4 MW (Table 5-3).[58] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 181,345.8 MW on September 30, 2022, a decrease of 4,771.6 MW or 2.6 percent from the January 1 level.[59] [60] The 4,771.6 MW decrease was the net result of an increase in exports (341.7 MW), a decrease in imports (469.3 MW), derates (1,187.2 MW), and deactivations or changes in capacity resource status (6,970.9 MW), partially offset by new or reactivated generation (3,870.3 MW) and net capacity modifications (327.2 MW).

At the beginning of the new delivery year on June 1, 2022, RPM installed capacity was 180,903.7 MW, an increase of 2,411.0 MW or 1.3 percent from the May 31, 2022, level of 183,314.7 MW. This change occurs as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

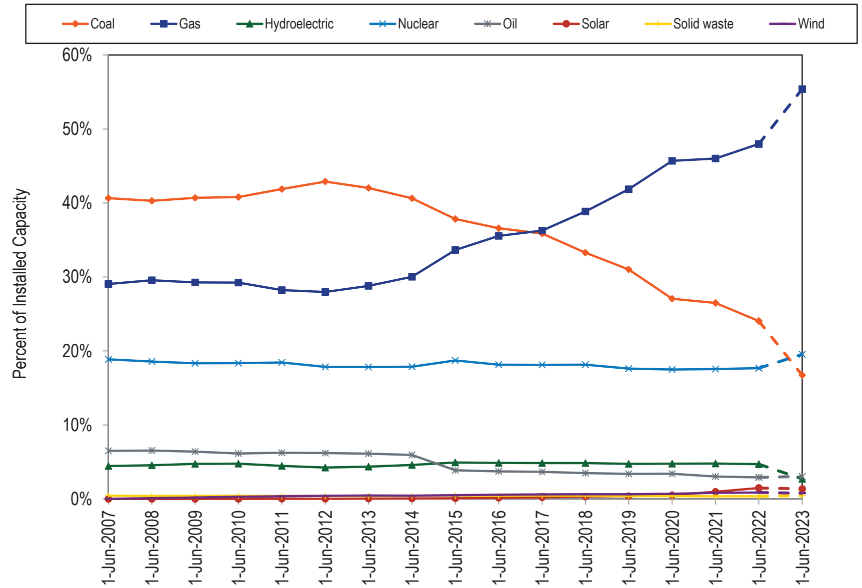
Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2022

	01-Jan-22		31-May-22		01-Jun-22		30-Sep-22	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	48,568.4	26.1%	46,902.0	25.6%	43,492.9	24.0%	42,805.1	23.6%
Gas	85,826.3	46.1%	86,113.3	47.0%	86,801.0	48.0%	87,930.0	48.5%
Hydroelectric	8,792.0	4.7%	8,789.6	4.8%	8,491.7	4.7%	8,491.7	4.7%
Nuclear	32,301.2	17.4%	31,971.0	17.4%	31,971.0	17.7%	31,971.0	17.6%
Oil	5,545.5	3.0%	5,365.4	2.9%	5,267.3	2.9%	5,267.3	2.9%
Solar	1,843.0	1.0%	1,997.0	1.1%	2,665.6	1.5%	2,666.5	1.5%
Solid waste	650.5	0.3%	650.4	0.4%	650.4	0.4%	650.4	0.4%
Wind	2,590.5	1.4%	1,526.0	0.8%	1,563.8	0.9%	1,563.8	0.9%
Total	186,117.4	100.0%	183,314.7	100.0%	180,903.7	100.0%	181,345.8	100.0%

58 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
59 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.
60 Wind resources accounted for 1,563.8 MW, and solar resources accounted for 2,666.6 MW of installed capacity in PJM on September 30, 2022. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 16 (August 1, 2021). The derating approach will be replaced with ELCC starting in the 2023/2024 Delivery Year.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2022, as well as the expected installed capacity for the 2023/2024 Delivery Year, based on the results of all auctions held through September 30, 2022.[61] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 24.0 percent on June 1, 2022, and is projected to decrease to 16.7 percent by June 1, 2023. The share of gas increased from 29.1 percent on June 1, 2007, to 48.0 percent on June 1, 2022, and is projected to increase to 55.4 percent on June 1, 2023.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2023



61 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2022, through September 30, 2022, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and September 30, 2022[62]

	01-Jan-22			31-May-22			01-Jun-22			30-Sep-22		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	20,801.5	12.1%	1	9.5	0.0%	119	7.0	0.0%	125	7.0	0.0%	122
Dominion Resources, Inc.	19,702.1	11.5%	2	19,851.8	11.7%	2	843.2	0.6%	30	828.8	0.6%	31
Vistra Energy Corp.	11,327.8	6.6%	3	9,977.7	5.9%	6	8,668.3	5.9%	5	8,667.3	5.9%	5
LS Power Group	11,253.4	6.5%	4	10,776.4	6.4%	4	10,803.4	7.3%	3	10,803.4	7.3%	3
Riverstone Holdings LLC	10,868.6	6.3%	5	10,719.1	6.3%	5	10,370.4	7.0%	4	10,370.4	7.0%	4
ArcLight Capital Partners, LLC	10,342.5	6.0%	6	14,744.3	8.7%	3	15,146.9	10.3%	2	15,146.9	10.2%	2
Constellation Energy Generation, LLC				20,273.6	12.0%	1	20,310.7	13.8%	1	20,306.9	13.7%	1

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2022, to September 30, 2022, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2022

	01-Jan-22		31-May-22		01-Jun-22		30-Sep-22	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	139,216.8	74.8%	136,451.8	74.4%	133,476.8	73.8%	133,969.1	73.9%
Nonmarket	46,900.6	25.2%	46,862.9	25.6%	47,426.9	26.2%	47,376.7	26.1%
Total	186,117.4	100.0%	183,314.7	100.0%	180,903.7	100.0%	181,345.8	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[63] The FDI_c is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type *i*. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. For all FDI calculations prior to June 1, 2023, the fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. Two additional fuel types, batteries and hybrid solar, are included beginning in the June 2023, calculation. The maximum achievable index with ten fuel types is 0.900.The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[64] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar

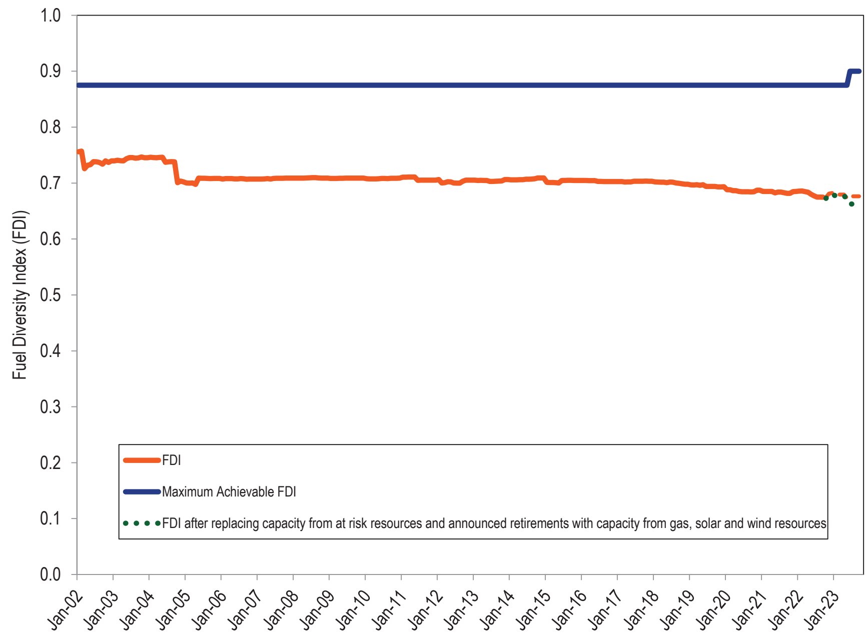
62 On February 2, 2022, Exelon and Constellation separated, with the generation portfolio in Constellation. On February 18, 2022, ArcLight closed on the acquisition of the generating portfolio of Public Service Enterprise Group.
63 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.
64 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.

but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[65] The average FDI_c for first nine months of 2022 decreased 0.5 percent compared to the first nine months of 2021. Figure 5-2 also includes the expected FDI_c through September 2023 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 3,447 MW of capacity were identified as being at risk of retirement. Generation owners that intend to retire a generator are required by the tariff to notify PJM in advance of the retirement (See Table 5-26).[66] There are 5,770.3 MW of generation that have a requested retirement date after September 30, 2022.[67] The dotted green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity from the at risk resources and other resources with deactivation notices is replaced by gas, wind and solar capacity.[68] [69] The FDI_c under these assumptions would decrease by 0.8 percent on average from the expected FDI_c for the period September 1, 2022, through September 1, 2023.

65 See the *2019 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.
66 See OATT Part V § 113.1.
67 See Table 12-11 in the *2022 Quarterly State of the Market Report for PJM: January through June*, Section 12: Generation and Transmission Planning.
68 It is assumed that 1,979.0 MW of replacement capacity is from solar units and 179.2 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 8,632.4 GWh of generation over the first nine months of the year assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-31 and Table 8-34. This level of GWh represents the increase in renewable generation required by RPS in 2023 over the level of renewable generation that was required by RPS in 2022. The split between solar and wind is based on queue data.
69 For this analysis resources for which PJM has received deactivation notifications were replaced with capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with capacity beginning on July 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2023



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for intermittent and storage resources including hydro, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[70]

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

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

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2021/2022 Delivery Year. The 19,655.3 MW increase was the result of new generation capacity resources (37,326.8 MW), reactivated generation capacity resources (1,380.4 MW), uprates (7,989.8 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (950.7 MW), offset by a net decrease in capacity imports (1,013.0 MW), deactivations (45,169.6 MW) and derates (3,777.3 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2018, through June 1, 2023, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2023, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity[71]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2021/2022 Delivery Year, internal installed capacity decreased by 2,249.9 MW after accounting for new capacity resources, reactivations, and uprates (46,697.0 MW) and capacity deactivations and derates (48,946.9 MW).

For the current and future delivery years (2022/2023 through 2023/2024), new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,552.0 MW) and pending deactivations (5,420.1 MW), PJM capacity is expected to decrease by 2,868.1 MW for the 2022/2023 through 2023/2024 Delivery Years.

71 For more details on future changes in generation capacity, see "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).

Table 5-6 Generation capacity changes: 2007/2008 through 2021/2022[72]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
Total	37,326.8	1,380.4	7,989.8	21,967.5	(1,013.0)	(950.7)	45,169.6	3,777.3	19,655.3

As shown in Table 5-7, total reserves on June 1, 2023, will be 24,792.3 MW, of which 7,835.3 MW are in excess of the required level of reserves, which is 16,957.0 MW. In the 2023/2024 BRA, 17,037.1 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,308.3 MW of intermittent and storage resources (3.7 percent of total cleared MW) were not offered in the 2023/2024 BRA.

The sum of cleared MW that were considered categorically exempt from the must offer requirement is 7,534.3 MW, or 44.4 percent of the required reserves and 30.4 percent of total reserves. The cleared MW of DR is 8,203.3 MW, or 48.4 percent of required reserves and 33.1 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.

72 The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2018, to June 1, 2023[73] [74]

	01-Jun-18	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	
Forecast peak load ICAP (MW)	152,407.9	151,643.5	148,355.3	149,482.9	149,263.6	149,680.0	A
FRR peak load ICAP (MW)	12,732.9	12,284.2	11,488.3	11,717.7	28,292.8	28,755.0	B
PRD ICAP (MW)	0.0	0.0	558.0	510.0	230.0	235.0	C
Installed reserve margin (IRM)	16.1%	16.0%	15.5%	14.7%	14.9%	14.8%	D
Pool wide average EFORd	6.07%	6.08%	5.78%	5.22%	5.08%	5.04%	E
Forecast pool requirement (FPR)	1.091	1.090	1.088	1.087	1.091	1.090	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	161,242.6	162,276.1	159,560.4	156,633.6	137,944.8	139,399.5	G
RPM committed less deficiency ICAP (MW) (generation and DR)	171,662.5	172,781.2	169,348.8	165,260.2	145,327.4	146,798.1	H=G/(1-E)
RPM peak load ICAP (MW)	139,675.0	139,359.3	136,309.0	137,255.2	120,740.8	120,690.0	J=A-B-C
Reserve margin ICAP (MW)	31,987.5	33,421.9	33,039.8	28,005.0	24,586.6	26,108.1	K=H-J
Reserve margin (%)	22.9%	24.0%	24.2%	20.4%	20.4%	21.6%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	9,499.8	11,124.4	11,911.9	7,828.5	6,596.3	8,246.0	M=K-D*J
Reserve margin in excess of IRM (%)	6.8%	8.0%	8.7%	5.7%	5.5%	6.8%	N=M/J
RPM peak load UCAP (MW)	131,196.7	130,886.3	128,430.3	130,090.5	114,607.2	114,607.2	P=J*(1-E)
RPM reliability requirement UCAP (MW)	152,315.6	151,832.0	148,331.5	149,210.1	131,679.9	131,564.2	Q=J*F
Reserve margin UCAP (MW)	30,045.9	31,389.8	31,130.1	26,543.1	23,337.6	24,792.3	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	8,927.0	10,444.1	11,228.9	7,423.5	6,264.9	7,835.3	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	22.9%	24.0%	24.2%	20.4%	20.4%	21.6%	U=(H-T/(1-E))/J-1

Sources of Funding[75]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 38,707.2 MW (82.9 percent of all additions), with 29,276.2 MW from market funding and 9,431.0 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 7,989.8 MW (17.1 percent of all additions), with 5,577.6 MW from market funding and 2,412.2 MW from nonmarket funding. In summary, of the 46,697.0 MW of additional capacity from new, reactivated, and uprated generation 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 the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2023/2024 Delivery Year, 2,554.9 MW are not yet in service. Of those 2,554.9 MW that have not yet gone into service, 2,408.7 MW have market funding and 146.2 MW have nonmarket funding. Applying the historical completion rates, 52.1 percent of all the projects in development are expected to go into service (1,232.4 MW of the 2,408.7 MW of in development market funded projects; 99.4 MW of the 146.2 MW of in development nonmarket funded projects). Together, 1,331.9 MW of the 2,554.9 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service in the 2023/2024 Delivery Year.

Of the 1,220.1 MW of the additional generation capacity that cleared in RPM auctions for the 2023/2024 Delivery Years and are already in service, 1,163.6 MW (95.4 percent) are based on market funding and 56.5 MW (4.6 percent) are based on nonmarket funding. In summary, 3,572.3 MW (94.6 percent) of the additional generation capacity (2,408.7 MW not yet in service and 1,163.6 MW in service) that cleared in RPM auctions for the 2023/2024 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 202.7 MW (5.4 percent) of proposed generation that cleared the RPM auction for the 2023/2024 Delivery Years.

73 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
74 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
75 For more details on sources of funding for generation capacity, see "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).

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

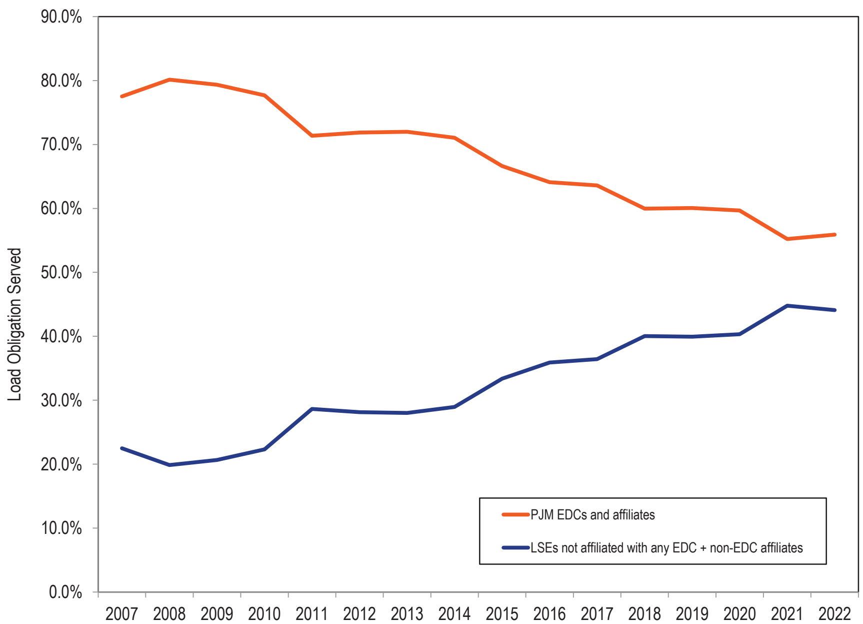
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2022, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 55.9 percent (Table 5-8), up from 55.2 percent on June 1, 2021. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 44.1 percent, down from 44.8 percent on June 1, 2021. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2022, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 55.9 percent on June 1, 2022. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 44.1 percent on June 1, 2022. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2021 and June 1, 2022

	01-Jun-21		01-Jun-22		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	96,306.4	55.2%	100,803.7	55.9%	4,497.4	0.7%
LSEs not affiliated with any EDC + non EDC Affiliates	78,114.1	44.8%	79,537.6	44.1%	1,423.6	(0.7%)
Total	174,420.4	100.0%	180,341.3	100.0%	5,920.9	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2022



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted six months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[76] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. 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.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2023/2024 RPM Base Residual Auction, BGE had 4,644.8 MW of CTRs with a total value of $34,782,061 and DPL South had -15.5 MW of CTRs with a total value of -$34,086.

MAAC had 1,182.2 MW of customer funded ICTRs with a total value of $6,645,843 and BGE had 65.7 MW of customer funded ICTRs with a total value of $491,985.

76 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 54 (Sep. 21, 2022).

MAAC had 560.3 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $3,150,053 and BGE had 306.0 MW with a value of $2,291,438.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[77] Figure 5-4 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2023/2024 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate.[78]

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[79] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the

77 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)]*.
78 See 117 FERC ¶ 61,331 (2006).
79 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

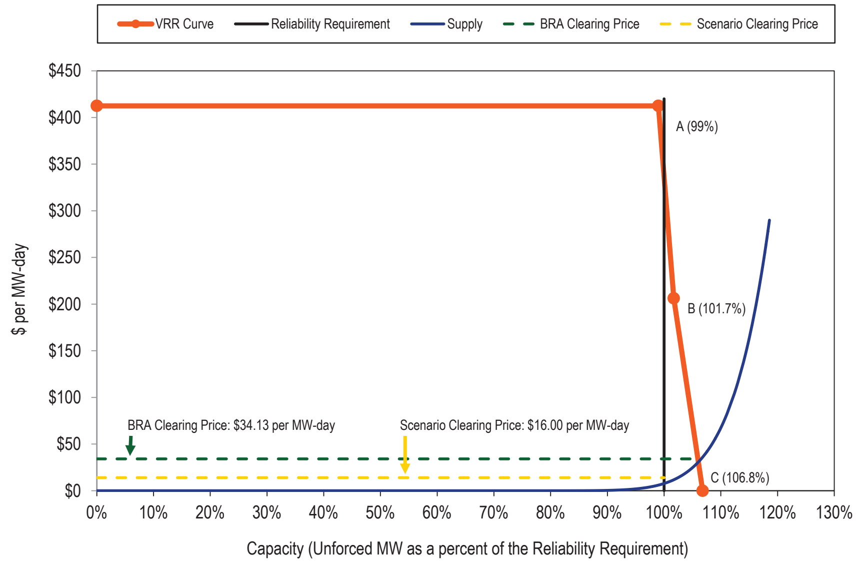
RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the 2023/2024 BRA. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve set equal to the reliability requirement.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If PJM had used a vertical demand curve set equal to the reliability requirement for 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $1,212,977,260, a decrease of $983,467,530, or 44.8 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 81.1 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2023/2024 RPM BRA. The clearing price and cleared quantity would have been lower if a vertical VRR curve set at the reliability requirement had been used in place of the existing VRR curve. In the 2023/2024 BRA, the RTO clearing price would have decreased from $34.13 per MW-day to $16.00 per MW-day, and the clearing quantity would have decreased from 144,870.6 MW to 131,820.4 MW.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2023/2024 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, 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.[80] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[81] [82] [83]

80 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
81 See OATT Attachment DD § 6.5.
82 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
83 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2020/2021 through 2023/2024 RPM Auctions[84]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2022/2023 Third Incremental Auction				
RTO	0.68	0.50	43	43
MAAC	0.40	0.05	9	9
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1

84 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[85] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[86] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[87] [88] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[89]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external

85 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
86 OATT Attachment DD § 5.10 (a) (ii).
87 146 FERC ¶ 61,052 (2014).
88 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Section 5 , "Capacity Market" at "Locational Deliverability Areas (LDAs)".
89 OATT Attachment DD § 5.6.6(b).

resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[90]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[91] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[92] [93] [94] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[95]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[96] [97] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[98] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[99]

90 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).
91 161 FERC ¶ 61,197 (2017).
92 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
93 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 54 (Sep. 21, 2022).
94 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 54 (Sep. 21, 2022).
95 OATT Schedule 1 § 1.10.1A.
96 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
97 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 54 (Sep. 21, 2022).
98 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
99 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

As shown in Table 5-10, of the 1,528.0 MW of imports offered 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.

Table 5-10 RPM imports: 2007/2008 through 2023/2024 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[100] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

There are two categories of demand side products included in the RPM market design:[101] [102]

- **Demand Resources (DR).** Interruptible load resource that is offered in an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the EE is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[103] The peak period definition for the EE Resource type is even more limited than Limited DR, including only the period from the hour ending 15:00 and the hour ending 18:00 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.[104]

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 Effective June 1, 2007, the PJM Active Load Management (ALM) program was replaced by the PJM Load Management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered in RPM Auctions as capacity resources and receive the clearing price.

102 Interruptible load for reliability (ILR) is an interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the Second Incremental Auction. The ILR product was eliminated as of the 2012/2013 Delivery Year.

103 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 6, Section L.

104 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Effective with the 2020/2021 Delivery Year, the Capacity Performance product includes two possible season types, annual and summer.

- Annual Capacity Performance Resources
  - **Annual Demand Resources.** A Demand Resource that is required to be available on any day during the Delivery Year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Efficiency Resource type includes the period between the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT from January 1 through February 28, excluding weekends and federal holidays.
- Seasonal Capacity Performance Resources
  - **Summer-Period Demand Resources.** A Demand Resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer Period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, 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 replacement capacity (574.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2019 to June 1, 2023[105 106 107]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-19	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,866.2	2,821.3	1,139.9	489.2	48.4	294.6	93.8	325.3	949.4	191.8	1,521.9	163.9	661.7	210.5	185.1
	EE cleared	5,734.8	2,303.6	1,265.3	499.4	53.5	431.0	201.6	287.5	485.0	55.9	792.6	211.9	312.4	129.4	186.8
	DR net replacements	(570.0)	(395.4)	(138.0)	(12.6)	1.7	(49.4)	(12.6)	(21.5)	(99.6)	(28.2)	127.5	8.9	(165.2)	(24.1)	24.3
	EE net replacements	(4.0)	11.8	7.0	14.9	0.0	(2.1)	15.4	8.7	(22.2)	(0.5)	0.0	6.2	(9.8)	(13.0)	0.0
	RPM load management	14,027.0	4,741.3	2,274.2	990.9	103.6	674.1	298.2	600.0	1,312.6	219.0	2,442.0	390.9	799.1	302.8	396.2
01-Jun-23	DR cleared	8,096.2	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	851.5	162.8	1,253.2	168.4	583.4	209.3	175.4
	EE cleared	5,471.1	2,198.2	1,178.7	540.1	51.2	383.1	175.9	283.1	424.8	42.9	961.2	257.0	287.9	93.5	157.3
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	13,567.3	4,609.6	2,154.6	883.7	103.4	655.8	302.0	458.3	1,276.3	205.7	2,214.4	425.4	871.3	302.8	332.7

105 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
106 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
107 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2023[108 109 110]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0		8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,510.7	1.091	9,281.7
01-Jun-23	8,096.2	0.0	0.0	8,096.2	0.0	8,096.2	0.0	1.090	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2023[111 112]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	5,734.8	0.0	(4.0)	5,730.8	0.0	5,730.8
01-Jun-23	5,471.1	0.0	0.0	5,471.1	0.0	5,471.1

108 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
109 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
110 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.
111 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.
112 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE addback rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

Capacity Value of Intermittent Resources (ELCC)

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

The contribution of intermittent and storage resources to reliability has been addressed in the PJM capacity market using derating factors in order to help ensure that MW of capacity are comparable, regardless of the source. Derating factors were used in the 2022/2023 BRA. On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[113] The MMU opposed the new ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented (putative) data as key inputs, among other issues, but does not oppose the ELCC approach in concept and when done correctly. [114] PJM's flawed ELCC approach will create new issues for the PJM capacity markets unless addressed promptly. If done correctly, including the application of ELCC to all resources, ELCC could be an advance over the current approach to defining the MW of capacity provided by all resource types, including intermittent resources.

PJM's flawed ELCC approach, based on static average rather than dynamic, market defined marginal values and basing the results on incorrect assumptions about the dispatch of some resource types, will create new issues for the PJM capacity markets unless addressed in the near future. If done correctly, ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly.

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. Both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations used in the 2023/2024 BRA are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity.

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. There is the related issue of ensuring that intermittent resources, like all other resources, are required to pay their own interconnection costs in order to meet their attributed capacity value, consistent with the longstanding PJM market design, or reduce their capacity value.

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs). If the intermittent resource or environmentally limited resource is deemed deliverable by PJM based on the additional CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year. Winter seasonal products have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. But this system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer.

113 See 176 FERC ¶ 61,056 (2021). There are multiple ways to apply the ELCC method. There is not a single ELCC method.

114 Comments and Motions of the Independent Market Monitor for PJM, Docket No. ER21-278 and EL19-100 (November 20, 2020). Answer and Motion for Leave to Answer and Alternative Motion for Consolidation of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 10, 2020). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 18, 2020). Comments and Motions of the Independent Market Monitor for PJM, ER21-278-001 (March 22, 2021). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (April 28, 2021).

PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. Those CIRs are not available to be sold to or provided to intermittent resources because they have been paid for by annual resources. The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[115] [116] [117] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps are defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[118] For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

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 costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[119] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[120] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges.[121] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held

115 See OATT Attachment DD § 6.5.
116 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).
117 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).
118 176 FERC ¶ 61,137 (2021).
119 OATT Attachment DD § 6.8 (b).
120 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).
121 For details on the competitive offer of a capacity performance resource, 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> (August 24, 2018).

after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[122]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[123] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR) including gross ACR, forward looking net revenues and the impact of the resource's performance during performance assessment intervals (A) in the delivery year on its risk and the cost to mitigate that risk.[124]

The competitive offer is based on 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. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices and net revenues. The actual prices in 2022 are about 120 percent higher through the end of September than prices for the same period in 2021. The forward curves reflect this change, but the historical net revenues do not.

But the current PJM method for calculating forward looking E&AS net revenues includes an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[125]

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which

122 OATT Attachment DD § 6.8(a).
123 151 FERC ¶ 61,208.
124 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.
125 *See* "PJM Manual 15: Cost Development Guidelines," Rev. 41 (October 1, 2022) § 12.7.

are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[126]

Under the original Capacity Performance design, the competitive offer of a resource was the larger of the asserted opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap based on its net ACR. But the default offer cap defined in the PJM tariff was based on strong assumptions that are not correct.

The circular logic of the offer cap derivation inevitably concluded that Net CONE times B was the competitive offer. The derivation is based on the assumption that Net CONE is the target clearing price for the capacity market. That assumption is the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, equals the market seller offer cap. The derivation is also based on the assumption that capacity resources have the ability to costlessly switch between capacity resource status and energy only status. That assumption is the basis for the assertion that an offer in the capacity market has an opportunity cost associated with the ability to be an energy only resource. But there is no such opportunity cost. The use of the offer cap is also based on a 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 offer cap 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.

126 OATT Attachment DD § 10A (d).

The PJM Capacity Market has a must offer requirement for a reason; it is required in order to ensure that the market can work, given the must buy obligation of load. A key ancillary benefit is that the must offer requirement helps prevent the exercise of market power by preventing withholding. If a capacity market seller wants to convert to energy only status, the owner must give up its CIRs. Such CIRs are likely to be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market. There have been effectively zero true PAI since the introduction of the capacity performance model. This does not mean that there will never be PAI or that there will never be 360 PAI. It does mean that it is not reasonable to include the assumption of 360 PAI in establishing the definition of a competitive offer in the capacity market. It does mean that there is no accurate way to calculate expected PAI for the market and that a design based on that calculation will not be based on market fundamentals. The bonus rate has been significantly lower than the penalty rate and there is no reason to expect that to change. As a result, it is not reasonable to include the assumption that CPBR equals PPR in defining a competitive offer in the capacity market. PJM's interpretation of the rules has led to the ability of nonperforming or underperforming resources to avoid penalty payments and to a corresponding reduction in bonus payments.

Net CONE times B was clearly well in excess of a competitive offer in the 2021/2022 BRA and 2022/2023 BRA whether compared to net ACR offers or compared to the actual offers of market participants. While the offer cap provided almost unlimited optionality to generation owners in setting offers, the actual clearing prices based on actual offers were generally about half of the offer caps. But some generation owners did successfully exercise market power within this design.

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.

The clearing prices for CP Resources in the 2022/2023 BRA were less than Net CONE times B for every zone. Of the 22 identified zones, the clearing price was less than 50 percent of Net CONE times B in 14 zones and less than 60 percent in 20 zones. The clearing price in BGE Zone was 68.4 of Net CONE times B and the clearing price in Penelec Zone, where Net CONE was lower than other zones, was 78.4 of Net CONE times B. Overall, the average clearing price was 43.6 percent of the average Net CONE times B.

The weighted average clearing prices in the 2023/2024 BRA were less than the corresponding offer cap based on Net CONE times B that would have been used absent the MSOC rule change for every zone. Of the 22 identified zones, the weighted average clearing price was less than 25 percent of Net CONE times B in 19 zones and less than 40 percent in all 22 zones. The weighted average clearing price in BGE Zone was 35.2 of Net CONE times B and the weighted average clearing price in PE Zone, where Net CONE was lower than other zones, was 32.2 of Net CONE times B. Overall, the average clearing price was 22.2 percent of the average Net CONE times B.

2023/2024 RPM Base Residual Auction

As shown in Table 5-14, 1,003 generation resources submitted offers in the 2023/2024 RPM Base Residual Auction. The MMU calculated unit specific ACR based offer caps for 73 generation resources (7.3 percent). Of the 1,003 generation capacity resources offered, 612 generation resources had default ACR based offer caps, 72 generation resources had unit specific ACR based offer caps, one generation resource had a unit specific opportunity cost based offer caps, 17 Planned Generation Capacity Resources had uncapped offers, 27 generation resources had uncapped planned uprates plus default ACR based offer caps for the existing portion of the units, three generation resources had uncapped planned uprates plus price taker status for the existing portion of the units, while the remaining 271 generation resources were price takers. Market power mitigation was applied to 32 Capacity Performance sell offers.

Table 5-14 ACR statistics: RPM auctions held through the first nine months of 2022

	2022/2023 Third Incremental Auction		2023/2024 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	0	0.0%	612	61.0%
Unit specific ACR (APIR)	0	0.0%	33	3.3%
Unit specific ACR (APIR and CPQR)	0	0.0%	9	0.9%
Unit specific ACR (non-APIR)	0	0.0%	13	1.3%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	17	1.7%
Opportunity cost input	0	0.0%	1	0.1%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	178	97.3%	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	27	2.7%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA
Uncapped planned uprate and price taker	0	0.0%	3	0.3%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	2	1.1%	17	1.7%
Existing generation resources as price takers	3	1.6%	271	27.0%
Total Generation Capacity Resources offered	183	100.0%	1,003	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[127] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

127 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[128] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[129]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[130] The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[131]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[132] The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.[133]

128 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
129 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
130 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).
131 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).
132 173 FERC ¶ 61,134 (2020).
133 177 FERC ¶ 61,209 (2021).

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-15, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2023/2024 RPM Base Residual Auction. Of the 12.3 MW offered that were subject to MOPR, 2.7 MW cleared and 9.6 MW did not clear.

Table 5-15 MOPR statistics: RPM auctions held through the first nine months of 2022[134]

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2022/2023 Third Incremental Auction	Capacity Resources with No State Subsidy	Unit Specific Exception	11	1,165.2	29.5	727.1	703.1	691.8
	Capacity Resources with State Subsidy - Cleared	Resource Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	Capacity Resources with State Subsidy - New	Resource Specific Exception	210	492.8	260.0	16.1	17.0	10.8
	Capacity Resources with No State Subsidy	Default	NA	NA	NA	0.0	0.0	0.0
	Capacity Resources with State Subsidy - Cleared	Default	NA	NA	NA	4,190.7	4,171.3	1,326.3
	Capacity Resources with State Subsidy - New	Default	NA	NA	NA	185.9	197.2	61.2
	Total		221	1,658.0	289.5	5,119.8	5,088.6	2,090.0
2023/2024 Base Residual Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	12.3	12.3	2.7
	Total		0	0.0	0.0	12.3	12.3	2.7

Replacement Capacity[135]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2023. The 2023 numbers are not final.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit

134 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers are not reported as a result of PJM confidentiality rules.

135 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[136]

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2023

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	145,066.9	0.0	0.0	145,066.9	0.0	145,066.9

Market Performance

Figure 5-5 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

136 See Monitoring Analytics, LLC, "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdff> (August 24, 2018).

Table 5-17 shows RPM clearing prices for the 2021/2022 through 2023/2024 Delivery Years for all RPM auctions held through the first nine months of 2022, and Table 5-18 shows the RPM cleared MW for the 2021/2022 through 2023/2024 Delivery Years for all RPM auctions held through the first nine months of 2022.

Figure 5-6 shows the RPM cleared MW weighted average prices for each LDA from the 2020/2021 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first nine months of 2022. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first nine months of 2022 based on the unforced MW cleared and the resource clearing prices. For the 2021/2022 Delivery Year, RPM revenue was $9.4 billion. For the 2022/2023 Delivery Year, RPM revenue was $4.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2022. In 2020, RPM revenue was $7.1 billion. In 2021, RPM revenue was $8.4 billion.

Table 5-22 shows the RPM annual charges to load. For the 2020/2021 Delivery Year, annual charges to load were $7.0 billion. For the 2021/2022 Delivery Year, annual charges to load are $9.4 billion.

Table 5-17 Capacity market clearing prices: 2021/2022 through 2023/2024 RPM Auctions

		RPM Clearing Price ($ per MW-day)													
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55
2022/2023 BRA	Capacity Performance	$50.09	$96.42	$50.09	$96.42	$97.75	$95.97	$97.75	$97.75	$97.75	$95.97	$50.09	$67.17	$107.92	$59.38
2022/2023 Third Incremental Auction	Capacity Performance	$50.05	$96.61	$50.05	$96.61	$97.93	$96.15	$97.93	$97.93	$97.93	$96.15	$50.05	$66.23	$108.22	$59.75
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13

Table 5-18 Capacity market cleared MW: 2021/2022 through 2023/2024 RPM Auctions[137]

		UCAP (MW)													
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3
2022/2023	THIRD	1,099.0	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	5,987.9
2023/2024	BASE	36,908.8	10,098.5	8,145.5	14,352.7	22,942.3	1,383.1	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	145,066.9

137 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2020/2021 through 2023/2024

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2020/2021	2021/2022	2022/2023	2023/2024
RTO				
AEP	$74.42	$133.84	$49.25	$34.13
APS	$74.42	$133.84	$49.25	$34.13
ATSI	$69.75	$142.59	$48.89	$34.13
Cleveland	$68.93	$90.81	$49.41	$34.13
COMED	$182.15	$189.54	$63.70	$34.13
DAY	$72.42	$132.69	$49.16	$34.13
DUKE	$121.24	$127.66	$70.57	$34.13
DUQ	$74.42	$133.84	$49.25	$34.13
DOM	$74.42	$133.84	$49.25	$34.13
EKPC	$74.42	$133.84	$49.25	$34.13
MAAC				
EMAAC				
ACEC	$182.04	$158.72	$96.30	$49.49
DPL	$182.04	$158.72	$96.30	$49.49
DPL South	$178.65	$159.65	$97.41	$69.95
JCPLC	$182.04	$158.72	$96.30	$49.49
PECO	$182.04	$158.72	$96.30	$49.49
PSEG	$165.74	$184.82	$90.67	$49.48
PSEG North	$176.45	$190.48	$89.21	$49.49
REC	$182.04	$158.72	$96.30	$49.49
SWMAAC				
BGE	$80.71	$174.43	$119.73	$69.94
PEPCO	$84.24	$133.37	$94.74	$49.46
WMAAC				
MEC	$81.85	$134.56	$94.49	$49.49
PE	$81.85	$134.56	$94.49	$49.49
PPL	$85.07	$138.51	$95.29	$49.49

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2023/2024[138]

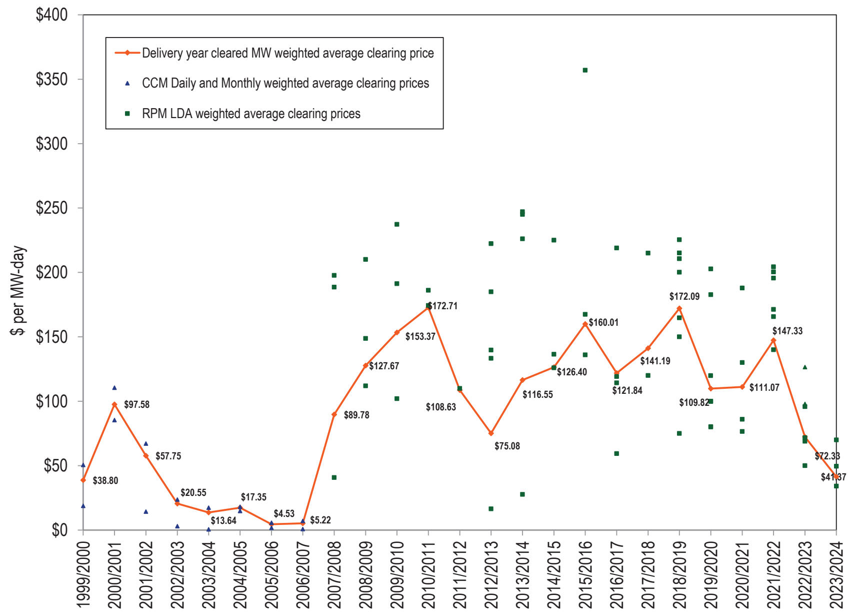
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$41.37	145,066.9	366	$2,196,444,804

Table 5-21 RPM revenue by calendar year: 2007 through 2024[139]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.18	147,067.8	365	$2,927,648,376
2024	$41.37	60,246.4	152	$912,184,727

138 The results for the ATSI Integration Auctions are not included in this table.
139 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-5 History of capacity prices: 1999/2000 through 2023/2024[140]



140 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2023/2024 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-6 Map of RPM capacity prices: 2020/2021 through 2023/2024

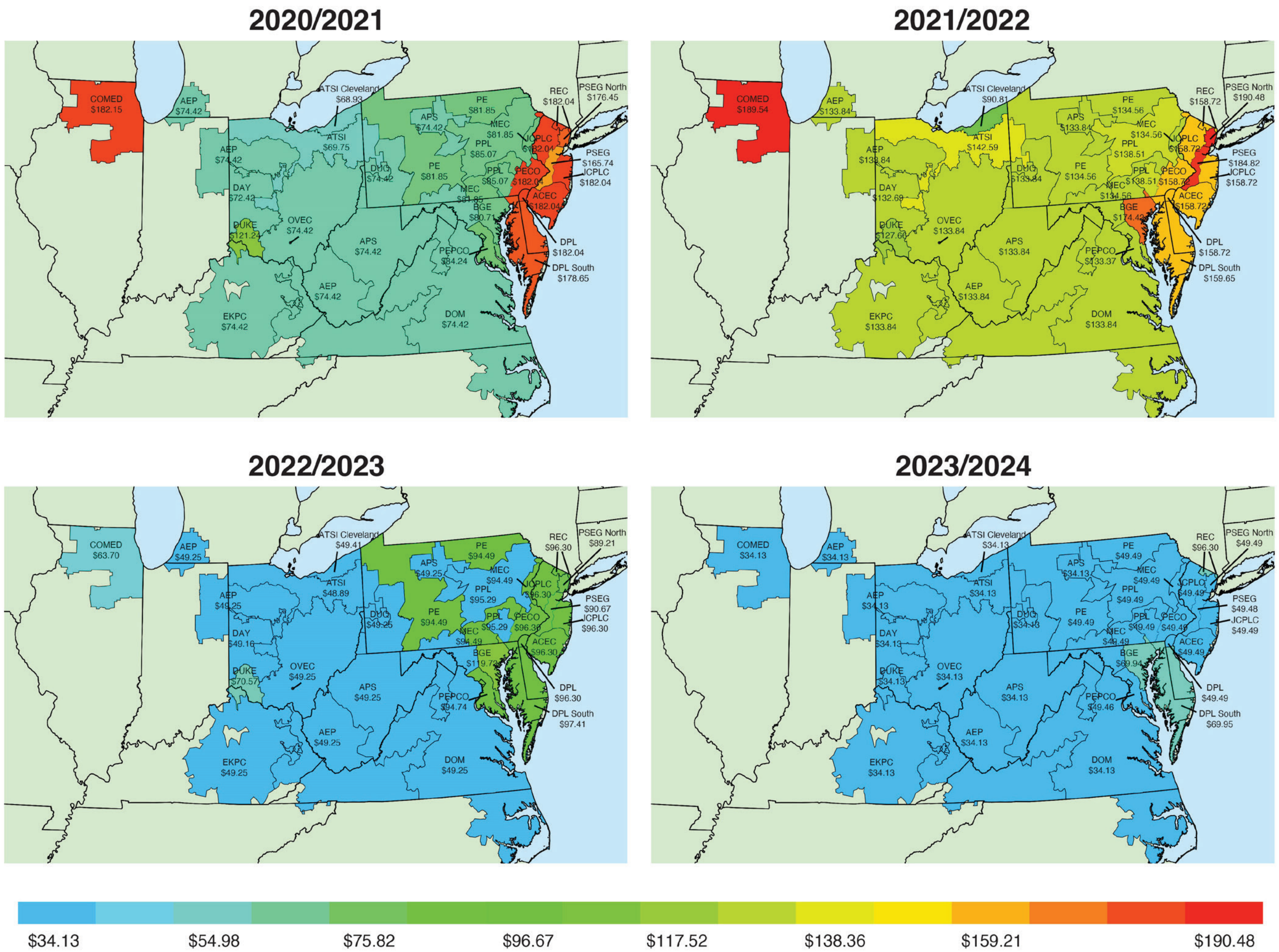


Table 5-22 RPM cost to load: 2021/2022 through 2023/2024 RPM Auctions[141][142][143]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2021/2022			
Rest of RTO	$142.16	82,768.3	$4,294,838,410
Rest of EMAAC	$164.73	23,719.9	$1,426,178,211
ATSI	$160.21	13,995.4	$818,411,597
BGE	$163.50	7,491.2	$447,049,048
COMED	$198.43	22,721.2	$1,645,630,168
PSEG	$188.46	10,987.4	$755,803,998
Total		161,683.4	$9,387,911,433
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DUKE	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.20	80,122.4	$1,002,804,217
EMAAC	$49.59	30,886.2	$560,568,565
WMAAC	$49.70	21,922.6	$398,766,226
DPL	$56.59	4,507.0	$93,342,868
BGE	$58.83	7,432.5	$160,042,845
Total		144,870.6	$2,215,524,721

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules 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.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[144][145][146][147][148][149] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would

141 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

142 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

143 The net load prices and obligation MW for 2023/2024 are not finalized.

144 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

145 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

146 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

147 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

148 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

149 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

CRF Issue[150]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[151] In the filing PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[152] [153]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{\mathrm{j}=1}^{\mathrm{L}}\frac{\mathrm{m_j}}{(1+\mathrm{r})^{\mathrm{j}}}\right]}{(1-s)\sqrt{1+\mathrm{r}}\,[(1+r)^N - 1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[154] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For

150 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
151 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
152 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
153 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.
154 Order 176 FERC ¶61,003 (July 2, 2021).

example, Table 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[155] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2022/2023 would not apply to the calculation of APIR values for projects that go into service for the 2022/2023 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission indicated that the issue is "beyond the scope" of the PJM filing.[156]

Table 5-24 Levelized CRF values: Delivery Year 2022/2023 through Delivery Year 2025/2026

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2022/2023	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026
1 to 5	30	0.088	0.091	0.094	0.096
6 to 10	25	0.093	0.096	0.098	0.101
11 to 15	20	0.101	0.104	0.107	0.110
16 to 20	15	0.116	0.119	0.122	0.126
21 to 25	10	0.147	0.152	0.158	0.164
25 Plus	5	0.246	0.258	0.271	0.283
Mandatory CapEx	4	0.296	0.312	0.328	0.345
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-25 Financial parameter and tax rate assumptions for CRF calculations

Financial Parameter	Parameter Value
Equity Funding Percent	45.000%
Debt Funding Percent	55.000%
Equity Rate	13.000%
Debt Interest Rate	6.000%
Federal Tax Rate	21.000%
State Tax Rate	9.300%
Effective Tax Rate	28.347%
After tax Weighted Average Cost of Capital	8.215%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-26).

Table 5-26 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following clendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[157] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[158]

155 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.

156 Order 176 FERC ¶61,003 (July 2, 2021) at 28.

157 OATT Attachment DD § 6.6(g).

158 OATT Part V §113.

Table 5-27 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through June 2022. Of the 133 deactivation requests submitted, 25 units (18.8 percent) deactivated an average of 186 days earlier than their initially requested date; 20 units (15.0 percent) deactivated an average of 84 days later than the originally requested deactivation date; and 52 units (39.1 percent) deactivated on their initially requested date. Fifteen (11.3 percent) of the unit deactivations were cancelled an average of 351 days before their scheduled deactivation date, and 21 (15.8 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-28 shows this information broken out by fuel types.

Table 5-27 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through September 2022

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	25	18.2%	(186)
Late	21	15.3%	80
On time	54	39.4%	0
Cancelled	15	10.9%	(351)
Pending	22	16.1%	-
Total	137	100.0%	-

Table 5-28 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through September 2022

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	100.0%	(4)
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	2	100.0%	-
Coal	Early	11	26.8%	(219)
	Late	8	19.5%	87
	On time	12	29.3%	0
	Cancelled	2	4.9%	(832)
	Pending	8	19.5%	-
	Total	41	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	4	100.0%	-
	Total	4	100.0%	-
Methane	Early	4	17.4%	(107)
	Late	6	26.1%	65
	On time	9	39.1%	0
	Cancelled	2	8.7%	(190)
	Pending	2	8.7%	-
	Total	23	100.0%	-
Natural Gas	Early	3	15.8%	(262)
	Late	3	15.8%	5
	On time	8	42.1%	0
	Cancelled	0	0.0%	-
	Pending	5	26.3%	-
	Total	19	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
	Total	10	100.0%	-
Oil	Early	3	9.4%	(218)
	Late	4	12.5%	146
	On time	21	65.6%	0
	Cancelled	1	3.1%	(105)
	Pending	3	9.4%	-
	Total	32	100.0%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	100.0%	-
Storage	Early	2	40.0%	-
	Late	0	0.0%	-
	On time	3	60.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	5	100.0%	-

Part V Reliability Service

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[159] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[160] It is essential that the deactivation provisions of the tariff be evaluated and modified. It is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[161] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[162] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service, generally only as an option in the event the unit is needed for reliability.[163] The PJM market rules do not require an owner to remain in service, but owners must provide advance notice of a proposed deactivation (See Table 5-26).[164] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[165] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[166]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[167] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[168] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[169] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[170] Project investment is capped at $2 million, above which FERC approval is required.[171] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[172]

Table 5-29 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022.

159 OATT Part V §114.
160 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").
161 OATT § 113.2; OATT Attachment M § IV.1.
162 OATT § 113.2.
163 *Id.*
164 OATT § 113.1.
165 OATT Attachment DD § 6.6(g).
166 *Id.*
167 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
168 OATT § 115.
169 *Id.*
170 OATT § 118.
171 OATT §§ 115, 117.
172 OATT § 119.

Table 5-29 Part V reliability service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Indian River 4	NRG Power Marketing LLC	411.9	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	31-Dec-26
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of eight owners have used the deactivation avoidable cost rate approach. The other six owners used the cost of service recovery rate.

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[173] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[174] [175] The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM.

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service.

This reliability service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual costs required to operate to provide the service.

173 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
174 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
175 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022)

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that this service should be provided under the deactivation avoidable cost rate in Part V, and that the investment cap under the avoidable cost rate option be eliminated.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of Part V reliability service and 20 percent for the provision of Part V reliability service in excess of two years.
- Add true up provisions that ensure that the service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the unit continues operation beyond the defined term of service.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-30 shows the capacity factors by unit type for the first nine months of 2021 and 2022. In the first nine month of 2022, nuclear units had a capacity factor of 95.3 percent, compared to 91.9 percent in the first nine months of 2021; combined cycle units had a capacity factor of 64.0 percent in the first nine months of 2022, compared to a capacity factor of 51.1 percent in the first nine months of 2021; coal units had a capacity factor of 44.1 percent in the first nine months of 2022, compared to 33.8 percent in the first nine months of 2021.

Table 5-30 Capacity factor (By unit type (GWh)): January through September, 2021 and 2022[176 177 178]

	2021 (Jan-Sep)		2022 (Jan-Sep)		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2022 from 2021
Battery	28.5	1.2%	17.4	0.9%	(0.4%)
Combined Cycle	215,859.9	51.1%	230,150.6	64.0%	12.9%
Single Fuel	188,707.4	54.1%	199,610.3	70.8%	16.7%
Dual Fuel	27,152.5	36.9%	30,540.3	39.4%	2.6%
Combustion Turbine	15,078.8	6.7%	15,023.8	7.9%	1.2%
Single Fuel	11,280.4	7.1%	10,226.6	7.7%	0.5%
Dual Fuel	3,798.4	5.8%	4,797.2	8.5%	2.7%
Diesel	234.1	6.9%	298.0	11.1%	4.2%
Single Fuel	219.9	7.9%	265.1	11.0%	3.2%
Dual Fuel	14.3	2.5%	32.9	12.1%	9.6%
Diesel (Landfill gas)	1,101.0	41.3%	937.2	48.7%	7.3%
Fuel Cell	166.0	79.3%	157.7	84.9%	5.6%
Nuclear	204,164.2	91.9%	204,420.6	95.3%	3.4%
Pumped Storage Hydro	4,907.9	11.3%	6,343.8	17.4%	6.1%
Run of River Hydro	8,161.5	31.2%	6,308.3	32.5%	1.3%
Solar	5,843.9	21.9%	7,564.1	23.1%	1.2%
Steam	161,005.7	30.5%	140,069.2	38.2%	7.7%
Biomass	4,352.8	56.4%	4,181.6	68.0%	11.7%
Coal	151,836.3	33.8%	130,356.4	44.1%	10.3%
Single Fuel	147,602.5	34.1%	128,038.0	44.4%	10.3%
Dual Fuel	4,233.8	25.2%	2,318.4	32.9%	7.6%
Natural Gas	4,057.6	34.6%	4,756.0	43.0%	8.4%
Single Fuel	414.4	41.1%	411.0	52.9%	11.8%
Dual Fuel	3,643.1	17.9%	4,345.0	21.5%	3.6%
Oil	759.1	3.0%	775.3	4.3%	1.3%
Wind	19,265.1	25.5%	21,865.6	29.2%	3.7%
Total	635,820.9	40.3%	633,156.3	48.7%	8.3%

176 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
177 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
178 Hours in which batteries have net negative generation do not count toward their runtime.

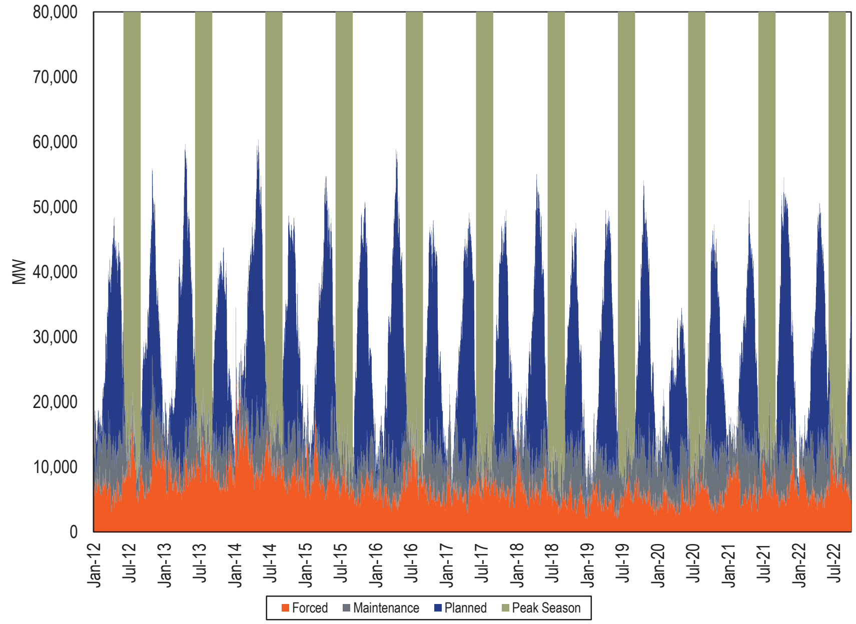
Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[179] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[180] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-7, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-7, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2022, the period ran from Monday, June 13 until Friday, September 9. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-4.

179 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).
180 OATT, Attachment K (Appendix) § 1.9.3 (b).

Figure 5-7 Outages (MW): January 2012 through September 2022



In the first nine months of 2022, forced outages were 2.0 percent higher, planned outages were 8.3 percent higher, and maintenance outages were 8.7 percent lower than in the first nine months of 2021.

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-8. Metrics by unit type are shown in Table 5-31.

Figure 5-8 Equivalent outage and availability factors: January through September, 2007 to 2022

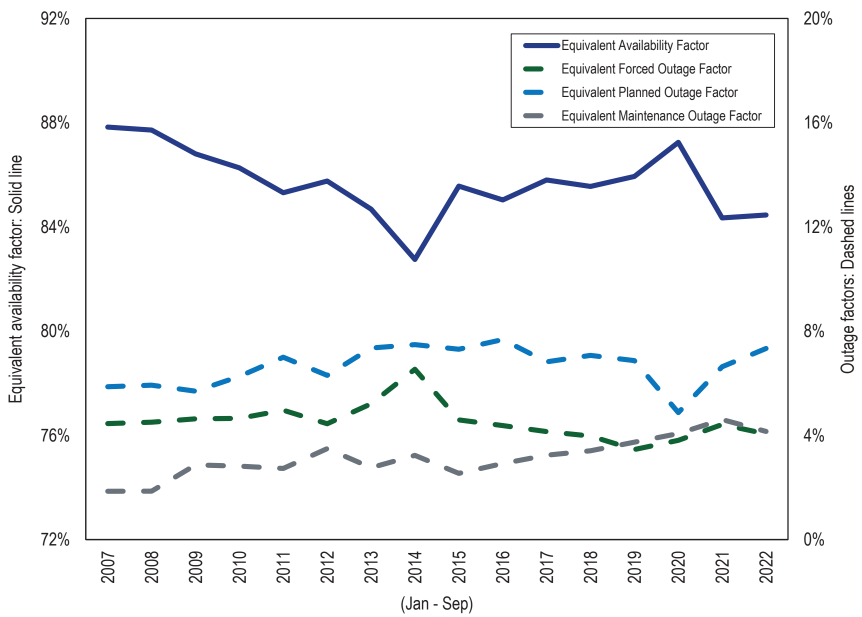


Table 5-31 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 through 2022

	Coal				Combined Cycle				Combustion Turbine				Diesel			
Year (Jan-Sep)	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	6.6%	8.1%	2.5%	82.7%	2.2%	5.2%	1.3%	91.2%	4.6%	2.3%	2.1%	91.0%	10.8%	0.7%	1.8%	86.7%
2008	7.8%	6.6%	2.4%	83.2%	2.1%	5.0%	1.4%	91.5%	3.0%	3.9%	1.9%	91.2%	9.8%	1.2%	1.2%	87.9%
2009	6.8%	6.8%	3.6%	82.8%	3.4%	5.1%	3.5%	88.0%	1.5%	2.7%	2.1%	93.8%	6.7%	0.3%	1.2%	91.8%
2010	7.8%	8.0%	4.2%	79.9%	2.6%	6.0%	3.1%	88.3%	2.0%	2.0%	1.6%	94.4%	4.7%	0.6%	0.8%	93.9%
2011	8.4%	8.3%	3.9%	79.5%	2.4%	7.0%	2.1%	88.5%	2.0%	3.2%	1.5%	93.3%	3.8%	0.0%	1.9%	94.3%
2012	7.4%	7.7%	6.0%	78.8%	2.5%	6.4%	1.8%	89.3%	1.9%	2.4%	1.5%	94.2%	3.9%	0.1%	1.7%	94.4%
2013	8.4%	9.4%	4.4%	77.8%	1.9%	8.5%	2.6%	87.0%	5.3%	3.1%	1.3%	90.2%	5.5%	0.3%	1.4%	92.8%
2014	10.4%	8.7%	5.0%	76.0%	2.8%	8.7%	2.1%	86.4%	7.8%	3.3%	1.4%	87.5%	14.1%	0.5%	2.0%	83.4%
2015	8.0%	7.6%	3.6%	80.7%	2.1%	8.3%	1.7%	87.9%	2.9%	4.1%	1.7%	91.2%	8.5%	0.4%	2.4%	88.7%
2016	7.8%	8.4%	5.0%	78.7%	3.0%	8.6%	1.7%	86.7%	2.2%	4.3%	1.9%	91.6%	5.5%	0.2%	2.6%	91.8%
2017	9.4%	8.6%	6.1%	75.9%	1.9%	7.9%	1.6%	88.6%	1.2%	3.9%	1.7%	93.2%	5.9%	0.2%	1.7%	92.2%
2018	8.7%	9.7%	6.2%	75.4%	1.5%	7.9%	1.2%	89.4%	2.0%	4.2%	1.5%	92.3%	6.2%	0.9%	2.7%	90.1%
2019	7.5%	7.9%	7.1%	77.5%	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.4%	1.0%	2.3%	89.3%
2020	5.5%	6.0%	8.8%	79.6%	3.6%	5.2%	2.2%	89.0%	1.7%	3.3%	1.6%	93.5%	6.4%	0.1%	2.5%	91.0%
2021	7.8%	9.3%	9.3%	73.7%	2.9%	7.3%	2.4%	87.4%	2.3%	5.0%	2.9%	89.7%	8.2%	0.5%	3.4%	87.8%
2022	7.3%	10.1%	9.2%	73.4%	3.1%	9.3%	1.8%	85.8%	2.6%	4.9%	2.1%	90.5%	10.1%	0.4%	4.2%	85.2%

	Hydroelectric				Nuclear				Other				Total			
Year (Jan-Sep)	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.2%	5.5%	1.7%	91.6%	1.2%	4.0%	0.3%	94.5%	6.0%	7.2%	2.8%	83.9%	4.4%	5.9%	1.9%	87.8%
2008	1.6%	7.1%	1.8%	89.5%	0.9%	5.0%	0.6%	93.4%	4.2%	8.7%	2.6%	84.4%	4.5%	5.9%	1.9%	87.7%
2009	2.2%	9.3%	2.4%	86.0%	4.3%	4.2%	0.7%	90.7%	3.4%	7.9%	5.0%	83.7%	4.6%	5.7%	2.9%	86.8%
2010	0.8%	8.2%	2.1%	88.9%	2.0%	4.7%	0.5%	92.7%	5.0%	8.3%	3.5%	83.3%	4.7%	6.3%	2.8%	86.3%
2011	1.5%	14.0%	2.0%	82.6%	2.4%	5.3%	1.6%	90.8%	5.2%	8.1%	3.0%	83.7%	5.0%	7.0%	2.7%	85.3%
2012	3.6%	4.2%	1.9%	90.4%	1.5%	6.1%	0.8%	91.7%	4.9%	8.4%	4.4%	82.3%	4.4%	6.3%	3.5%	85.8%
2013	2.2%	6.8%	1.7%	89.3%	1.0%	5.3%	0.6%	93.1%	6.9%	9.4%	3.6%	80.0%	5.2%	7.4%	2.8%	84.7%
2014	2.1%	9.2%	3.2%	85.5%	1.7%	5.2%	0.9%	92.2%	6.8%	12.6%	5.8%	74.8%	6.5%	7.5%	3.2%	82.8%
2015	2.4%	8.3%	1.5%	87.8%	1.2%	4.4%	1.4%	93.0%	6.6%	15.5%	4.3%	73.6%	4.6%	7.3%	2.5%	85.6%
2016	2.1%	6.8%	2.9%	88.2%	1.9%	4.6%	1.0%	92.5%	5.1%	16.4%	3.8%	74.7%	4.4%	7.7%	2.9%	85.0%
2017	2.0%	5.6%	3.0%	89.4%	0.6%	4.7%	0.6%	94.1%	4.4%	8.7%	5.1%	81.9%	4.1%	6.8%	3.2%	85.8%
2018	2.0%	5.0%	3.3%	89.7%	0.7%	4.6%	0.5%	94.2%	4.0%	8.2%	8.2%	79.7%	4.0%	7.1%	3.4%	85.6%
2019	1.2%	4.7%	3.8%	90.2%	0.7%	4.8%	1.1%	93.4%	3.9%	10.0%	6.6%	79.5%	3.5%	6.9%	3.7%	85.9%
2020	3.9%	3.1%	2.6%	90.3%	1.5%	3.9%	0.7%	93.9%	7.7%	6.6%	5.1%	80.7%	3.8%	4.9%	4.1%	87.2%
2021	7.1%	3.3%	2.4%	87.2%	0.9%	4.4%	1.4%	93.4%	7.8%	6.4%	6.0%	79.8%	4.4%	6.6%	4.6%	84.3%
2022	2.6%	6.0%	2.8%	88.6%	1.3%	4.4%	1.2%	93.1%	6.4%	7.2%	5.9%	80.5%	4.1%	7.3%	4.1%	84.5%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[181] The EFORd metric includes all forced outages, regardless of the reason for those outages.

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. Figure 5-9 shows the average EFORd since 1999 for all units in PJM.[182]

Figure 5-9 Equivalent demand forced outage rates (EFORd): 1999 through 2022

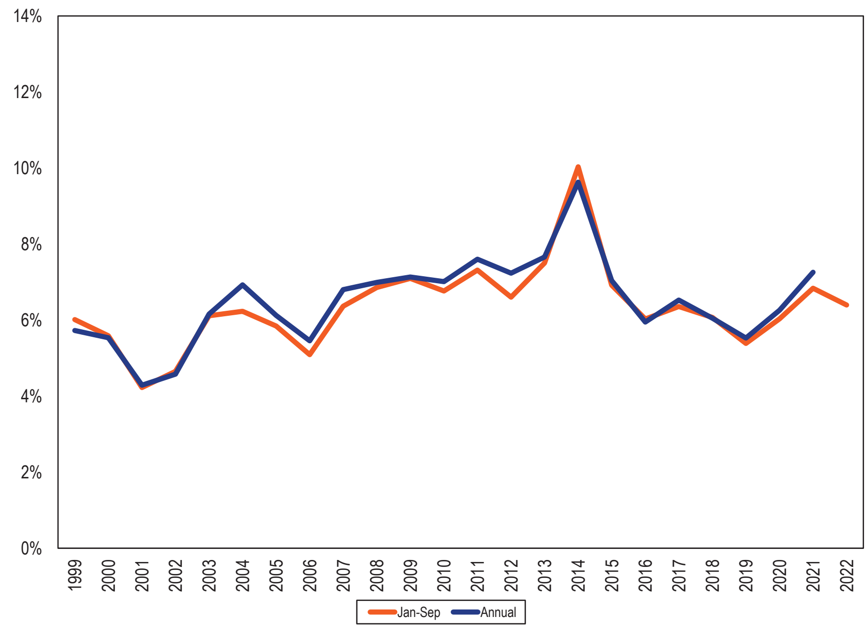


Table 5-32 shows the class average EFORd by unit type.

Table 5-32 EFORd by unit type: January through September, 2007 through 2022

	Jan-Sep															
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	7.5%	8.8%	8.4%	9.3%	10.7%	9.9%	10.7%	13.0%	9.4%	9.5%	11.6%	11.1%	10.0%	8.4%	10.5%	9.9%
Combined Cycle	3.7%	3.5%	4.8%	3.6%	3.1%	3.1%	2.6%	4.6%	2.8%	3.6%	2.4%	2.2%	2.0%	4.1%	3.8%	4.0%
Combustion Turbine	11.2%	11.3%	9.1%	9.1%	7.8%	6.5%	10.5%	17.7%	9.9%	5.3%	4.9%	6.4%	5.0%	4.1%	5.3%	5.6%
Diesel	12.3%	10.8%	8.8%	6.7%	9.6%	4.7%	6.1%	15.1%	9.8%	7.0%	7.2%	6.8%	8.0%	7.7%	10.5%	13.0%
Hydroelectric	1.8%	2.6%	2.8%	1.3%	2.0%	5.2%	3.4%	3.2%	3.2%	3.0%	2.9%	2.7%	1.6%	5.2%	9.0%	3.8%
Nuclear	1.3%	1.0%	4.4%	2.2%	2.6%	1.6%	1.1%	1.9%	1.2%	2.2%	0.6%	0.8%	0.7%	1.5%	1.0%	1.4%
Other	10.2%	9.6%	8.5%	7.9%	9.3%	8.3%	11.5%	12.9%	13.1%	9.8%	12.9%	9.6%	9.6%	17.0%	18.2%	16.7%
Total	6.4%	6.9%	7.1%	6.8%	7.3%	6.6%	7.5%	10.0%	6.9%	6.0%	6.4%	6.1%	5.4%	6.0%	6.8%	6.4%

181 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.

182 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2021 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

EFORd vs EAF

EFORd is not an adequate measure of units' availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[183] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-33 shows the differences between EFORd and EAF by unit type. For the 2021/2022 Base Residual Auction, total offered UCAP (Unforced Capacity) calculated using the EFORd was 126,452 MW. If EAF were used to calculate available capacity, total available capacity for the 2021/2022 BRA would have been 10.0 percent lower, 114,313 MW.

Table 5-33 EFORd and EAF by unit type: January through September, 2012 through 2022

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Year (Jan - Sep)	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	9.9%	21.2%	3.1%	10.7%	6.5%	5.8%	4.7%	5.6%	5.2%	9.6%	1.6%	8.3%	8.3%	17.7%	6.6%	14.2%
2013	10.7%	22.2%	2.6%	13.0%	10.5%	9.8%	6.1%	7.2%	3.4%	10.7%	1.1%	6.9%	11.5%	20.0%	7.5%	15.3%
2014	13.0%	24.0%	4.6%	13.6%	17.7%	12.5%	15.1%	16.6%	3.2%	14.5%	1.9%	7.8%	12.9%	25.2%	10.0%	17.2%
2015	9.4%	19.3%	2.8%	12.1%	9.9%	8.8%	9.8%	11.3%	3.2%	12.2%	1.2%	7.0%	13.1%	26.4%	6.9%	14.4%
2016	9.5%	21.3%	3.6%	13.3%	5.3%	8.4%	7.0%	8.2%	3.0%	11.8%	2.2%	7.5%	9.8%	25.3%	6.0%	15.0%
2017	11.6%	24.1%	2.4%	11.4%	4.9%	6.8%	7.2%	7.8%	2.9%	10.6%	0.6%	5.9%	12.9%	18.1%	6.4%	14.2%
2018	11.1%	24.6%	2.2%	10.6%	6.4%	7.7%	6.8%	9.9%	2.7%	10.3%	0.8%	5.8%	9.6%	20.3%	6.1%	14.4%
2019	10.0%	22.5%	2.0%	11.2%	5.0%	8.5%	8.0%	10.7%	1.6%	9.8%	0.7%	6.6%	9.6%	20.5%	5.4%	14.1%
2020	8.4%	20.4%	4.1%	11.0%	4.1%	6.5%	7.7%	9.0%	5.2%	9.7%	1.5%	6.1%	17.0%	19.3%	6.0%	12.8%
2021	10.5%	26.3%	3.8%	12.6%	5.3%	10.3%	10.5%	12.2%	9.0%	12.8%	1.0%	6.6%	18.2%	20.2%	6.8%	15.7%
2022	9.9%	26.6%	4.0%	14.2%	5.6%	9.5%	13.0%	14.8%	3.8%	11.4%	1.4%	6.9%	16.7%	19.5%	6.4%	15.5%
Average	10.4%	22.9%	3.2%	12.2%	7.4%	8.6%	8.7%	10.3%	3.9%	11.2%	1.3%	6.9%	12.7%	21.1%	6.7%	14.8%

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[184] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

183 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

184 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EFOF was 4.1 percent in the first nine months of 2022. Table 5-34 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 14.1 percent of the system EFOF, were the largest single contributor to EFOF.

Table 5-34 Contribution to PJM EFOF by unit type by cause: January through September, 2022

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	18.9%	7.5%	0.0%	0.0%	0.0%	0.0%	17.9%	14.1%
Electrical	2.2%	28.7%	12.8%	2.3%	0.2%	25.0%	2.4%	7.8%
Unit Testing	4.0%	8.1%	13.9%	39.4%	6.0%	5.6%	22.7%	7.7%
Miscellaneous (External)	11.3%	1.0%	0.2%	0.2%	0.3%	1.1%	0.2%	6.9%
Fuel Quality	8.3%	0.3%	0.0%	10.1%	0.0%	0.0%	0.7%	5.1%
Boiler Air and Gas Systems	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%	5.3%	4.5%
Auxiliary Systems	2.7%	8.0%	5.2%	0.1%	0.3%	0.0%	1.2%	3.3%
Wet Scrubbers	5.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	3.2%
Miscellaneous (Gas Turbine)	0.0%	6.9%	23.4%	0.0%	0.0%	0.0%	0.0%	3.0%
Boiler Fuel Supply from Bunkers to Boiler	4.3%	0.6%	0.0%	0.0%	0.0%	0.0%	0.4%	2.7%
Boiler Piping System	3.7%	1.4%	0.0%	0.0%	0.0%	0.0%	1.0%	2.5%
Stack Emission	2.5%	1.2%	1.1%	0.0%	0.0%	0.0%	7.5%	2.5%
Exciter	2.0%	7.7%	2.3%	0.0%	0.2%	0.0%	0.0%	2.4%
Boiler Fuel Supply to Bunker	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%	2.4%
Cooling System	3.5%	0.1%	0.0%	0.0%	3.5%	0.0%	0.2%	2.2%
Generator	0.2%	4.1%	6.3%	2.9%	4.7%	0.0%	6.7%	2.1%
Feedwater System	1.9%	1.9%	0.0%	0.0%	0.0%	6.5%	1.1%	1.9%
Inlet Air System and Compressors	0.0%	1.9%	16.7%	0.0%	0.0%	0.0%	0.0%	1.7%
Turbine	0.0%	0.1%	1.8%	0.0%	63.2%	0.0%	0.0%	1.7%
All Other Causes	19.2%	20.6%	16.3%	45.1%	21.5%	61.8%	26.5%	22.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The PJM EMOF was 4.1 percent in the first nine months of 2022. Table 5-35 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 13.6 percent of the system EMOF, were the largest single contributor to system EMOF.

Table 5-35 Contribution to EMOF by unit type by cause: January through September, 2022

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	18.0%	14.1%	0.0%	0.0%	0.0%	0.0%	9.9%	13.6%
Boiler Overhaul and Inspections	13.1%	0.0%	0.0%	0.0%	0.0%	0.0%	15.4%	9.9%
Low Pressure Turbine	13.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.4%
Boiler Air and Gas Systems	6.9%	1.9%	0.0%	0.0%	0.0%	0.0%	21.1%	6.8%
Boiler Fuel Supply from Bunkers to Boiler	8.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	5.4%
Boiler Tube Fireside Slagging or Fouling	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	4.3%
Electrical	1.7%	1.1%	24.2%	0.3%	8.4%	0.0%	6.0%	4.2%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	58.7%	0.0%	3.4%
Condensing System	3.0%	8.0%	0.0%	0.0%	0.0%	1.4%	6.0%	3.3%
Wet Scrubbers	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%
Miscellaneous (Gas Turbine)	0.0%	8.7%	24.0%	0.0%	0.0%	0.0%	0.0%	2.8%
Fuel, Ignition and Combustion Systems	0.0%	22.9%	7.1%	0.0%	0.0%	0.0%	0.0%	2.6%
Auxiliary Systems	2.2%	3.0%	5.3%	0.0%	0.8%	0.0%	3.0%	2.5%
Feedwater System	1.8%	3.6%	0.0%	0.0%	0.0%	0.0%	6.3%	2.1%
Boiler Piping System	1.6%	8.4%	0.0%	0.0%	0.0%	0.0%	3.7%	2.1%
Valves	1.9%	5.6%	0.0%	0.0%	0.0%	0.5%	2.0%	1.9%
Miscellaneous (Generator)	0.2%	1.5%	3.0%	33.4%	28.8%	5.1%	0.7%	1.9%
Miscellaneous (Balance of Plant)	1.0%	6.0%	2.3%	0.9%	0.0%	0.0%	2.8%	1.7%
Slag and Ash Removal	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	1.6%
All Other Causes	12.5%	14.9%	34.2%	65.5%	62.0%	34.4%	22.6%	18.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 7.3 percent in the first nine months of 2022. Table 5-36 shows the causes of EPOF by unit type. Planned outages for miscellaneous gas turbine issues, 20.2 percent of the system EPOF, were the largest single contributor to system EPOF.

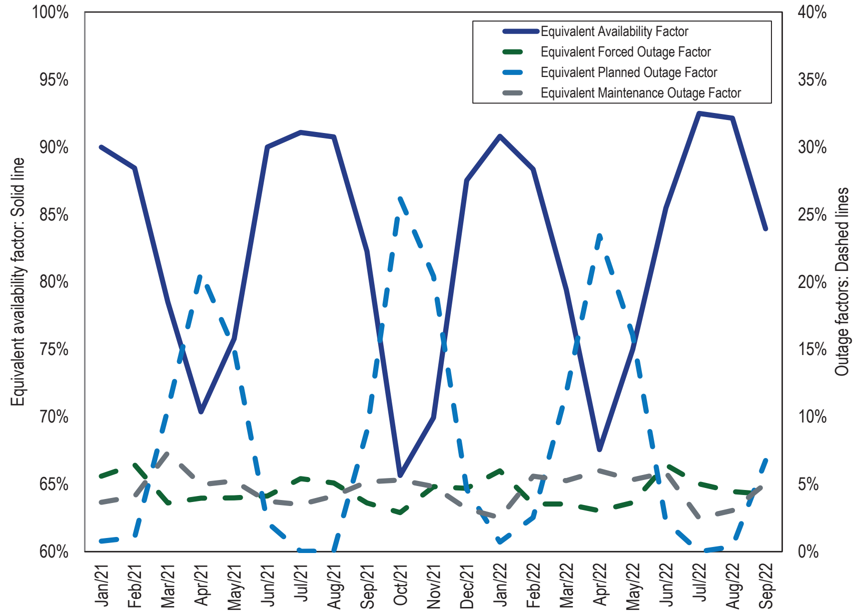
Table 5-36 Contribution to EPOF by unit type and cause: January through September, 2022

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Gas Turbine)	0.0%	49.9%	62.0%	0.0%	0.0%	0.0%	0.0%	20.2%
Boiler Overhaul and Inspections	31.6%	5.4%	0.0%	0.0%	0.0%	0.0%	29.6%	15.9%
Miscellaneous (Balance of Plant)	18.9%	18.7%	7.1%	57.5%	2.2%	0.0%	2.8%	13.3%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	91.5%	0.0%	11.2%
Slag and Ash Removal	13.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.1%
Miscellaneous (Steam Turbine)	8.1%	3.5%	0.0%	0.0%	0.0%	0.0%	3.1%	4.3%
Miscellaneous (Generator)	4.4%	0.2%	4.0%	23.5%	6.2%	0.0%	10.2%	3.3%
Low Pressure Turbine	6.1%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	55.2%	0.0%	0.0%	2.1%
High Pressure Turbine	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%
Electrical	0.0%	0.7%	7.9%	0.0%	19.6%	0.1%	0.0%	1.9%
Miscellaneous (Boiler)	3.3%	0.6%	0.0%	0.0%	0.0%	0.0%	5.4%	1.9%
Boiler Air and Gas Systems	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	1.6%
Generator	0.0%	1.9%	4.8%	0.0%	11.5%	0.0%	0.0%	1.5%
Controls	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	12.0%	1.3%
NOx Reduction Systems	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
Miscellaneous (Pollution Control Equipment)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.6%	1.2%
Miscellaneous Boiler Tube Problems	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Boiler Tube Leaks	1.7%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	0.7%
All Other Causes	2.3%	9.5%	14.1%	19.0%	5.3%	8.4%	16.5%	7.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-10.

Figure 5-10 Monthly generator performance factors: January 2021 through September 2022



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[185] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[186] Wind and solar resources do not perform verification tests to prove capability.[187]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[188]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[189]

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted in the resource's commitment plus the greater of 20 percent of that clearing

185 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 51 (Oct. 20, 2021).

186 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 54 (Sep. 21, 2022).

187 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, 54 (Sep. 21, 2022).

188 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.

189 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 54 (Sep. 21, 2022).

price or 20 dollars per MW-day.[190 191] Generation owners also have the option to buy replacement capacity that satisfies the same locational requirements.[192 193] There were no such charges assessed for the first nine months of 2022. There were no such charges assessed for 2021.

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by power meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[194] Only forced outages are defined as non-performance. In the first nine months of 2022, PAIs occurred on June 13, June 14, and June 15, for which performance results have not yet been published.

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[195 196] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. There were no such charges assessed in the first nine months of 2022. There were no such charges assessed in 2021.

190 OATT, Attachment DD (Reliability Pricing Model) § 7.
191 For auction clearing prices, see Table 5-17
192 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 16 (Aug. 1, 2021).
193 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
194 OATT, Attachment DD (Reliability Pricing Model) § 10A.
195 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 54 (Sep. 21, 2022).
196 OATT, Attachment DD (Reliability Pricing Model) § 8.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014 (Table 5-37).

Table 5-37 Changed outages by unit type: January 2014 through September 2022[197]

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Coal	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	179,687
	2021	0	NA	0	NA	1	2,018,208
	2022 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	12	773,779	0	NA	234	7,763,613
Combined Cycle	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022 (Jan-Sep)	0	NA	1	3,817	0	NA
	Total	7	34,690	11	373,648	87	743,443
Combustion Turbine	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022 (Jan-Sep)	0	NA	0	NA	1	0
	Total	9	26,990	6	57,104	188	266,572
Diesel	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	25,659
	2022 (Jan-Sep)	2	1,478	0	NA	1	57
	Total	26	2,132	0	NA	1,291	80,760

197 Year describes the year in which the outage started and not the year in which the outage designation was changed.

Table 5-37 Changed outages by unit type: January 2014 through September 2022 (continued)

Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	392,737
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	264,872
	2021	0	NA	0	NA	33	263,525
	2022 (Jan-Sep)	0	NA	0	NA	1	4,850
	Total	12	135,420	0	NA	913	5,443,158
Nuclear	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	0	NA	2	178,191	2	22,903
Other	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	12	252,111	2	37,294	47	566,132
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,311,353
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	616,175
	2021	3	137	7	303,061	42	2,332,486
	2022 (Jan-Sep)	2	1,478	1	3,817	3	4,907
	Total	78	1,225,122	21	646,237	2,762	14,886,581

Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[1] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  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.[2]

  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.[3] 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.[4]

- **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.

1 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.
2 The total credits and MWh numbers for demand resources were downloaded as of October 6, 2022 and may change as a result of continued PJM billing updates.
3 Economic credits are synonymous with revenue received for reductions under the economic load response program.
4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 88 (Oct. 1, 2022).

Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

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.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. 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

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

be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends 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.)
- 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.[7])
- 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.)

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

7 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 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.)
- 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.)

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.[8] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance is be measured under the current economic demand response CBL rules which means relying on load

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

9 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed April 28, 2022).

10 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed April 28, 2022).

estimates rather than actual metered load.[11] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, 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.

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.[12] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic, emergency and pre-emergency programs, or Price Responsive Demand (PRD). Table 6-1 provides an overview of the key features of PJM demand response programs.

Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participate in the capacity market and energy market.[13] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

FERC Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[14] PJM implemented rules that require PJM to verify with EDCs that no law or

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

12 577 U.S. 260 (2016).

13 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.

14 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

regulation of a RERRA prohibits end use customers' participation.[15] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to provide additional verification.[16] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)			Economic Demand Response	
Product Types	Capacity Performance, Summer-Period Capacity Performance OATT Attachmend DD § 5.5A	Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachemnt K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	RPM event RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

15 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.
16 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania (e.g. Pennsylvania ACT 129 Utility Program) and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.[17]

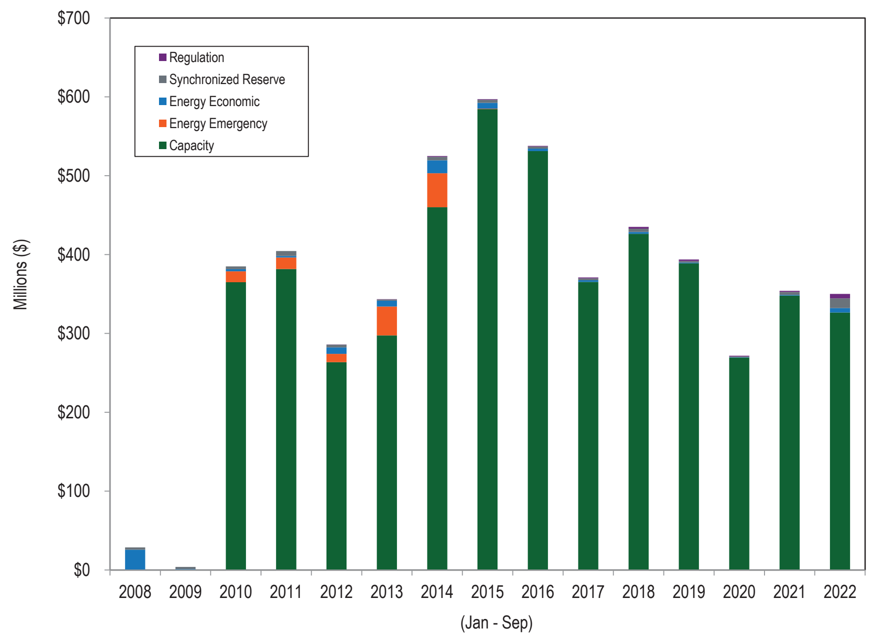
PJM Demand Response Programs

Figure 6-1 shows all revenue from PJM demand response programs by market for the first nine months of each year, 2008 through 2022. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[18] In the first nine months of 2022, 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. 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. This decrease consisted of capacity market revenue.[19] In the first nine months of 2022, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 93.3 percent of all revenue received by demand response providers, the economic program for 1.6 percent, synchronized reserve for 3.5 percent and the regulation market for 1.6 percent.

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.[20] 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.

Lower demand resource revenues in the first nine months of 2022, compared to the first nine months of 2021, are primarily due to capacity market revenues. The RTO clearing price for the RPM Base Residual Auction for Delivery Year 2021/2022 was $140.00 per MW-day. The RTO clearing price for the RPM Base Residual Auction for the 2022/2023 Delivery Year was $50.00 per MW-day, 64.3 percent lower than the clearing price for the RTO Base Residual Auction for the 2021/2022 Delivery Year. The capacity revenue amounts for four of the nine months of 2021 are from the 2021/2022 Delivery Year and the capacity revenue amounts for four of the nine months of 2022 are from the 2022/2023 Delivery Year.

Figure 6-1 Demand response revenue by market: January through September, 2008 to 2022



17 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 122 (Oct. 1, 2022).
18 This includes both capacity market revenue and emergency energy revenue for capacity resources.
19 The total credits and MWh for demand resources were downloaded as of October 6, 2022 and may change as a result of continued PJM billing updates.
20 Economic credits are synonymous with revenue received for reductions under the economic load response program.

Emergency and Pre-Emergency Load Response Programs

Demand resources participate in the capacity market within the Emergency and Pre-Emergency Load Response Programs.

All demand resources must register as pre-emergency unless the participant relies on behind the meter generation and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[21] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. CSPs satsify cleared RPM commitments registerting customers as Nominated MW. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

The emergency and pre-emergency load response programs consist of the base and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year requires all emergency or pre-emergency demand resources to be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[22]

All capacity performance resource types must respond during a Performance Assessment Interval (PAI). Demand resources are the only capacity performance resource types that trigger a PAI when dispatched by PJM. PJM eliminated any substantive difference between pre-emergency and emergency by making the dispatch of either type trigger a PAI.

The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. Demand resources are not required to meet the same requirements as other capacity resources for the PAI.

Demand resources are also not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer daily into the day-ahead energy market.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the day-ahead energy market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends eliminating the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[23]

Market Structure

The HHI for demand resources showed that ownership was highly concentrated for the 2021/2022 Delivery Year, with an HHI value of 2070. In the 2021/2022 Delivery Year, the four largest companies contributed 85.3 percent of all committed demand resources UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2022/2023 Delivery Year, with an HHI value of 2051. In the 2022/2023 Delivery Year, the four largest companies own 82.8 percent of all committed demand response UCAP MW.

21 OA Schedule 1 § 8.5.
22 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM. *See* PJM OATT RAA Article 1.
23 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-2 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-2 HHI value for committed UCAP MW by LDA by delivery year: 2021/2022 and 2022/2023 Delivery Years[24]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2021/2022	ATSI	924.0	2212	High
	ATSI-CLEVELAND	272.8	4800	High
	BGE	279.0	2171	High
	COMED	2,073.7	2492	High
	DAY	227.7	2748	High
	DEOK	220.5	2131	High
	DPL-SOUTH	66.3	4622	High
	EMAAC	904.7	1852	High
	MAAC	750.0	1868	High
	PEPCO	345.9	1995	High
	PPL	697.7	2034	High
	PS-NORTH	188.6	2184	High
	PSEG	221.9	1835	High
	RTO	4,254.9	2462	High
2022/2023	ATSI	757.6	2267	High
	ATSI-CLEVELAND	191.8	2589	High
	BGE	163.9	3049	High
	COMED	1,521.9	2515	High
	DAY	210.5	2709	High
	DEOK	185.1	2354	High
	DPL-SOUTH	48.4	4936	High
	EMAAC	796.9	2157	High
	MAAC	530.5	2185	High
	PEPCO	325.3	3163	High
	PPL	661.7	2143	High
	PS-NORTH	93.8	2613	High
	PSEG	200.8	2060	High
	RTO	3,178.0	2247	High

Market Performance

Table 6-3 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 2,561.5 MW, or 22.4 percent, from 11,427.7 MW in the 2021/2022 Delivery Year to 8,866.2 MW in the 2022/2023 Delivery Year. The DR percent of capacity decreased by 0.6 percentage points, from 6.5 percent in the 2021/2022 Delivery Year to 5.9 percent in the 2022/2023 Delivery Year.

24 The RTO LDA refers to the rest of RTO.

Table 6-3 Cleared Demand Resource UCAP MW: 2007/2008 through 2022/2023 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,139.6	1.4%
2012/2013	8,740.9	141,061.8	6.2%
2013/2014	10,779.6	159,830.5	6.7%
2014/2015	14,943.0	161,092.4	9.3%
2015/2016	15,453.7	173,487.4	8.9%
2016/2017	13,265.3	179,749.0	7.4%
2017/2018	11,870.5	180,590.3	6.6%
2018/2019	11,435.4	175,957.4	6.5%
2019/2020	10,703.1	177,040.6	6.0%
2020/2021	9,445.7	173,688.5	5.4%
2021/2022	11,427.7	174,713.0	6.5%
2022/2023	8,866.2	150,465.2	5.9%

Table 6-4 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2022. Capacity market revenue decreased in the first nine months of 2022 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. The RTO clearing price for the RPM Base Residual Auction for the 2021/2022 Delivery Year was $140.00 per MW-day. The RTO clearing price for the RPM Base Residual Auction for the 2022/2023 Delivery Year was $50.00 per MW-day, 64.3 percent lower than the clearing price for the RTO Base Residual Auction for the 2021/2022 Delivery Year. The capacity revenue amounts for four of the nine months of 2021 are from the 2021/2022 Delivery Year and the capacity revenue amounts for four of the nine months of 2022 are from the 2022/2023 Delivery Year.

Table 6-4 Zonal monthly demand resource capacity revenue: January through September, 2022

Zone	January	February	March	April	May	June	July	August	September	Total
ACEC	$428,479	$387,013	$428,479	$414,657	$428,479	$182,606	$188,693	$188,693	$182,606	$2,829,706
AEP, EKPC	$8,020,032	$7,243,900	$8,020,032	$7,761,321	$8,020,032	$2,385,300	$2,464,810	$2,464,810	$2,385,300	$48,765,536
APS	$4,439,739	$4,010,087	$4,439,739	$4,296,522	$4,439,739	$1,003,500	$1,036,950	$1,036,950	$1,003,500	$25,706,727
ATSI	$6,106,337	$5,515,401	$6,106,337	$5,909,358	$6,106,337	$1,400,571	$1,447,257	$1,447,257	$1,400,571	$35,439,426
BGE	$1,209,572	$1,092,516	$1,209,572	$1,170,553	$1,209,572	$618,432	$639,046	$639,046	$618,432	$8,406,741
COMED	$11,191,922	$10,108,833	$11,191,922	$10,830,892	$11,191,922	$2,827,436	$2,921,684	$2,921,684	$2,827,436	$66,013,731
DAY	$988,218	$892,584	$988,218	$956,340	$988,218	$315,750	$326,275	$326,275	$315,750	$6,097,628
DOM	$828,075	$747,939	$4,965,896	$801,363	$828,075	$398,094	$1,156,409	$1,156,409	$1,119,105	$12,001,365
DPL	$4,965,896	$4,485,326	$1,037,801	$4,805,706	$4,965,896	$1,119,105	$467,487	$467,487	$452,406	$22,767,110
DUKE	$1,037,801	$937,369	$828,075	$1,004,324	$1,037,801	$452,406	$411,364	$411,364	$398,094	$6,518,599
DUQ	$587,636	$530,768	$587,636	$568,680	$587,636	$222,900	$230,330	$230,330	$222,900	$3,768,816
JCPLC	$874,938	$790,267	$874,938	$846,714	$874,938	$433,911	$448,375	$448,375	$433,911	$6,026,368
MEC	$1,570,553	$1,418,564	$1,570,553	$1,519,890	$1,570,553	$662,963	$685,062	$685,062	$662,963	$10,346,162
PE	$2,293,438	$2,071,493	$1,593,409	$2,219,456	$2,293,438	$1,069,806	$890,253	$890,253	$861,536	$14,183,083
PECO	$1,593,409	$1,439,208	$2,293,438	$1,542,009	$1,593,409	$861,536	$1,105,466	$1,105,466	$1,069,806	$12,603,747
PEPCO	$978,670	$883,960	$978,670	$947,100	$978,670	$455,338	$470,516	$470,516	$455,338	$6,618,777
PPL	$2,980,867	$2,692,396	$2,980,867	$2,884,710	$2,980,867	$1,901,527	$1,964,912	$1,964,912	$1,901,527	$22,252,586
PSEG	$2,586,854	$2,336,513	$2,586,854	$2,503,407	$2,586,854	$864,887	$893,716	$893,716	$864,887	$16,117,690
REC	$29,798	$26,915	$29,798	$28,837	$29,798	$4,697	$4,854	$4,854	$4,697	$164,249
TOTAL	$52,712,236	$47,611,052	$52,712,236	$51,011,841	$52,712,236	$17,180,765	$17,753,458	$17,753,458	$17,180,765	$326,628,046

Pre-Emergency and Emergency Load Response resources must register all resources to respond within 30, 60 or 120 minutes of a PJM dispatched event. The quick lead time, or 30 minute lead time, is the default lead time, unless a CSP submits an exception request for 60 or 120 minute notification time based on a physical constraint.[25] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18.[26] Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-5 shows the amount of nominated MW and locations by product type and lead time for the 2021/2022 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 3,213 locations, or 20.9 percent of all locations, which have 3,645.6 nominated MW, or 45.8 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2021/2022 Delivery Year.

25 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 52 (Feb. 24, 2022).
26 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 52 (Feb. 24, 2022).

Table 6-5 Nominated MW and locations by product type and lead time: 2021/2022 Delivery Year

Lead Type	Pre-Emergency MW	Emergency MW	Total
Quick Lead (30 Minutes)	4,114.1	203.8	4,317.9
Short Lead (60 Minutes)	285.5	21.0	306.5
Long Lead (120 Minutes)	3,198.2	140.8	3,339.1
Total	7,597.9	365.7	7,963.5
Lead Type	Pre-Emergency Locations	Emergency Locations	Total
Quick Lead (30 Minutes)	11,702	444	12,146.0
Short Lead (60 Minutes)	331	37	368.0
Long Lead (120 Minutes)	2,658	187	2,845.0
Total	14,691	668	15,359.0

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2022/2023 Delivery Year. PJM approved 3,192 locations, or 18.5 percent of all locations, which have 4,095.8 nominated MW, or 47.3 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2022/2023 Delivery Year.

Table 6-6 Nominated MW and locations by product type and lead time: 2022/2023 Delivery Year

Lead Type	Pre-Emergency MW	Emergency MW	Total
Quick Lead (30 Minutes)	4,374.2	191.7	4,565.9
Short Lead (60 Minutes)	353.8	21.0	374.8
Long Lead (120 Minutes)	3,574.1	146.9	3,721.0
Total	8,302.2	359.6	8,661.8
Lead Type	Pre-Emergency Locations	Emergency Locations	Total
Quick Lead (30 Minutes)	13,642	389	14,031.0
Short Lead (60 Minutes)	317	36	353.0
Long Lead (120 Minutes)	2,657	182	2,839.0
Total	16,616	607	17,223.0

A Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from PJM. This default 30 minute prior notification applies unless a CSP obtains an exception from PJM due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. The only alternative notification times that PJM will permit are 60 minutes and 120 minutes. The CSP must submit in writing that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception.

The request for an exception must demonstrate one of four defined reasons:[27]

- The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- Transfer of load to backup generation requires time intensive manual process taking more than 30 minutes;
- Onsite safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within 30 minutes due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

Table 6-7 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2022/2023 Delivery Year.[28]

Table 6-7 Nominated MW and locations of granted lead time exceptions: 2022/2023 Delivery Year

	Short Lead (60 Minutes)	Long Lead (120 Minutes)	
Reason	MW	MW	Total
Generation Start Time	53.9	816.1	870.0
Manufacturing Damage	253.3	1,919.6	2,172.9
Safety Problem	67.5	985.4	1,052.9
Total	374.8	3,721.0	4,095.8
	Short Lead (60 Minutes)	Long Lead (120 Minutes)	
Reason	Locations	Locations	Total
Generation Start Time	67	452	519
Manufacturing Damage	207	797	1,004
Safety Problem	79	1,590	1,669
Total	353	2,839	3,192

There are two ways to measure load reductions of demand resources. The Firm Service Level (FSL) method, applied to the summer, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF).[29] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of

27 OATT Attachment DD-1, Section A.2(a).

28 Data for generation start time and mass market communication categories were combined based on confidentiality rules.

29 Real-time load is hourly metered load.

the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[30] With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) and the LF, rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.[31] The Winter Peak Load is adjusted up for transmission and distribution line loss factors because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.[32]

The capacity market is an annual market. A Capacity Performance resource has an annual commitment. Effective with the 2020/2021 Delivery Year, the capacity market design includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource. Capacity Market Sellers may submit sell offers of either Summer Period Capacity Performance Resources or Winter Period Capacity Performance Resources and the auction clearing optimization algorithm is designed to clear equal quantities of offsetting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer Period Capacity Performance Resource with a Winter Period Capacity Performance Resource. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of capacity MW allocated to load does not vary based on winter demand. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[33] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[34] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. If an end customer has 3 MW of load during the coincidental peak load hour, but only 1 MW during the coincidental winter peak load hour, the end use customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.[35] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

30 135 FERC ¶ 61,212 (2011).
31 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 52 (Feb. 24, 2022).
32 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 52 (Feb. 24, 2022).
33 OATT Attachment DD.5.11.
34 OATT Attachment M-2.
35 162 FERC ¶ 61,159 (2018).

Table 6-8 shows the MW registered by measurement and verification method and by technology type for the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-8 Nominated MW by each demand response method: 2022/2023 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,251.0	2,152.1	189.8	757.4	4,238.4	22.8	48.4	8,659.9	99.98%
Guaranteed Load Drop	0.3	1.5	0.0	0.0	0.1	0.0	0.0	1.9	0.02%
Total	1,251.3	2,153.5	189.8	757.4	4,238.5	22.8	48.4	8,661.8	100.0%
Percent by method	14.4%	24.9%	2.2%	8.7%	48.9%	0.3%	0.6%	100.0%	

Table 6-9 shows the fuel type used in the onsite generators for the 2022/2023 Delivery Year in the emergency and pre-emergency programs. For the 2022/2023 Delivery Year, 1,251.3 MW of the 8,661.8 nominated MW, 14.4 percent, used onsite generation. Of the 1,251.3 MW, 83.4 percent used diesel and 16.6 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-9 Onsite generation fuel type (MW): 2022/2023 Delivery Year

	2022/2023	
Fuel Type	MW	Percent
Diesel	1,043.0	83.4%
Natural Gas, Gasoline, Oil, Propane, Waste Products	208.3	16.6%
Total	1,251.3	100.0%

Table 6-10 shows the MW registered by measurement and verification method and by technology type for the 2021/2022 Delivery Year. For the 2021/2022 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-10 Nominated MW by each demand response method: 2021/2022 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,232.1	1,911.6	191.1	666.4	3,903.7	17.2	39.9	7,962.0	99.98%
Guaranteed Load Drop	0.3	1.0	0.0	0.0	0.0	0.0	0.3	1.5	0.02%
Total	1,232.3	1,912.6	191.1	666.4	3,903.7	17.2	40.1	7,963.5	100.0%
Percent by method	15.5%	24.0%	2.4%	8.4%	49.0%	0.2%	0.5%	100.0%	

Table 6-11 shows the fuel type used in the onsite generators for the 2021/2022 Delivery Year in the emergency and pre-emergency programs. For the 2021/2022 Delivery Year, 1,232.3 MW of the 7,963.5 nominated MW, 15.5 percent, use onsite generation. Of the 1,232.3 MW, 83.5percent use diesel and 16.5 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-11 Onsite generation fuel type (MW): 2021/2022 Delivery Year

	2021/2022	
Fuel Type	MW	Percent
Diesel	1,029.1	83.5%
Natural Gas, Gasoline, Oil, Propane, Waste Products	203.2	16.5%
Total	1,232.3	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity resources measure performance nodally, except for demand resources. 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.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.[36] With the full implementation of the Capacity Performance rules in the 2020/2021 Delivery Year, the requirement that subzones be defined one day prior to dispatch is no longer in effect. A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, as defined by the zip code of the enrolled end use customer's address, the entire registration must respond. Subzonal dispatch creates a PAI for the subzone, even if PJM does not measure compliance for demand resources. There are currently seven defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN and AEP_MARION.[37] The AEP_MARION subzone was added as a result of the June 14-16, 2022, performance assessment event in the Columbus, Ohio area of the AEP Zone.

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK subzones were removed by PJM. More subzones may have been removed by PJM but PJM does not keep a record of created and removed subzones. The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. The 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.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[38] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[39] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the Rest of RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs. These interfaces correspond to LDAs as defined in RPM.[40]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes, the event is not measured for compliance.

Demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five

36 OATT Attachment DD, Section 11.

37 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed June 14, 2022).

38 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.

39 See the *2018 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

40 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 52 (Feb. 24, 2022).

minute basis, a five minute interval meter is required. All other capacity resources require five minute interval meters, and demand resources should be no different. Demand resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance on a five minute basis to accurately report reductions during demand response events. The current rules for demand response use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each five minute interval of the event and is inconsistent with the measurement of generation resources. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[41]

Under the capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment intervals (PAI).[42] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. PJM cannot dispatch pre-emergency or emergency demand response without triggering a PAI and measuring compliance. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now effectively classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. Table 6-12 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2021/2022 and 2022/2023 Delivery Years. There are 8,129.7 nominated MW of demand response for the 2022/2023 Delivery Year, 45.2 percent of the required reserve margin and 29.6 percent of the actual reserve margin for the 2022/2023 Delivery Year.[43]

41 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 52 (Feb. 24, 2022).
42 OATT § 1 (Performance Assessment Hour).

Table 6-12 Demand response nominated MW compared to reserve margin: 2021/2022 and 2022/2023 Delivery Years[44]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2021/2022	10,512.1	20,176.5	52.1%	28,005.0	37.5%
2022/2023	8,129.7	17,990.4	45.2%	27,449.9	29.6%

PJM will dispatch demand resources by zone or subzone for demand resources, or within a PAI area for Capacity Performance resources. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency Action Area (EAA).[45] [46] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation

43 *2022 Quarterly State of the Market Report for PJM: January through June*, Section 5: Capacity, Table 5-7.
44 Nominated MW totals are Demand Response ICAP corresponding to Demand Response UCAP cleared in RPM auctions for each delivery year. The total nominated MW values do not reflect replacement transactions.
45 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.
46 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 52 (Feb. 24, 2022).

of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Definition of Compliance

PJM's reporting of load management events overstates performance of demand side resources. Limiting reported compliance to only positive values incorrectly reports compliance. Settlement locations with a negative load reduction value (load increase) are not included in compliance reporting by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a negative performance value. PJM limits reported compliance shortfall values to zero MW. But the PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[47] The compliance formulas for FSL and GLD customers do allow negative values. The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources. Changing a demand resource compliance calculation from a negative value to 0 MW also inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstate the true value and capacity of demand resources.

For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

The MMU recommends that PJM correctly report compliance to include negative values when calculating event compliance across hours and registrations.

Demand resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as Economic Resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[48] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage.

The MMU recommends that PJM Manual 11 be revised to require, rather than recommend, that the RRMSE test be applied to all demand resources with a CBL.[49]

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends capping demand reductions based entirely on behind the meter generation at the lower of economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would

47 OA Schedule 1 § 8.9.

48 157 FERC ¶ 61,067 (2016).

49 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 12 (Oct. 1, 2022).

have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[50] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[51] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance.[52]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment, but the testing requirements are inadequate.[53] The CSP must notify PJM of the intent to test 48 hours in advance of the test. A notification of intent to test must be submitted in the DR Hub system. If a CSP failed to provide the required load reduction in a zone by less than 25 percent of their Summer Average RPM Commitment in the zone, the CSP may conduct a retest of the subset of registrations in the zone that failed. If the CSP elects to not retest a subset of registrations that failed the test, such registrations will maintain the compliance result achieved in the initial test. Retesting must be performed at the same time of day and under approximately the same weather conditions. Multiple tests may be conducted; however, only one test result may be submitted for each end use customer site in the DR Hub System for compliance evaluation. Test data must be submitted on or after June and no later than July 14th after the delivery year.

The ability of CSPs to pick the test time does not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. Given that demand resources are now an annual product, multiple tests are required

50 OA Schedule 1 § 8.2.

51 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.

52 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.

53 The mandatory response time for Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: PJM Capacity Market," Rev. 52 (Feb. 24, 2022).

to ensure reduction capability year round. The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event.

Table 6-13 shows the test penalties by delivery year by product type for the 2016/2017 Delivery Year through the 2021/2022 Delivery Year.[54] The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. The total penalty column is the sum of the daily test penalties by delivery year and type. Total Load Management Test Compliance penalties were 0.23 percent of total DR revenues in the 2021/2022 Delivery Year.

Table 6-13 Test penalties by delivery year by product type: 2016/2017 through 2021/2022

	2016/2017			2017/2018			2018/2019			2019/2020			2020/2021			2021/2022		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665	0.03	$179.80	$2,100									
Extended Summer	7.3	$138.14	$370,290	10.5	$142.86	$547,928												
Annual	4.8	$137.45	$241,406	16.3	$144.00	$855,940												
Base DR and EE							16.3	$186.80	$1,110,134	30.2	$154.69	$1,712,177						
Capacity Performance	2.1	$160.80	$124,310	0.6	$181.80	$40,146	2.6	$188.55	$178,795				0.9	$125.30	$39,422	23.1	$176.79	$1,487,430
Total	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678	18.9	$187.03	$1,291,030	30.2	$154.69	$1,712,177	0.9	$125.30	$39,422	23.1	$176.79	$1,487,430

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[55] There are 98.2 percent of nominated MW for the 2022/2023 Delivery Year registered under the full program option. There are 1.8 percent of nominated MW for the 2022/2023 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[56] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[57] [58] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[59] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.

54 Not all products received penalties or existed in every delivery year. For example, the Base and Capacity Performance products were not an option for the 2020/2021 Delivery Year.
55 *Id.*
56 161 FERC ¶ 61,153 at P 8 (2017).
57 139 FERC ¶ 61,057 (2012).
58 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
59 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[60]

Table 6-14 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2021/2022 Delivery Year. The majority of participants, 77.3 percent of locations and 52.1 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2021/2022 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.3 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $166.11 per location and $147.51 per nominated MW.

Table 6-14 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2021/2022 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	107	0.7%	207.8	2.7%	$97.45	$20.58
$1,000-$1,275	2,912	19.5%	3,214.4	41.4%	$166.11	$147.51
$1,275-$1,550	367	2.5%	295.3	3.8%	$44.06	$54.75
$1,550-$1,849	11,511	77.3%	4,046.8	52.1%	$50.83	$144.59
Total	14,897	100.0%	7,764.4	100.0%	$73.53	$141.09

Table 6-15 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2022/2023 Delivery Year. The majority of participants, 80.3 percent of locations and 51.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.8 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $168.12 per location and $138.97 per nominated MW.

60 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 41 (Oct. 1, 2022).

Table 6-15 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2022/2023 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	119	0.7%	187.1	2.2%	$89.05	$32.97
$1,000-$1,275	2,854	16.9%	3,514.7	41.6%	$168.12	$138.97
$1,275-$1,550	353	2.1%	374.8	4.4%	$43.95	$41.39
$1,550-$1,849	13,532	80.3%	4,365.0	51.7%	$41.90	$129.90
Total	16,858	100.0%	8,441.6	100.0%	$62.73	$125.27

PRD

Price Responsive Demand, or PRD, in the capacity market is capacity based on a firm commitment reduce load in response to a defined level of real-time energy prices. A PRD offer is a commitment to reduce energy usage by a defined amount in response to real time energy prices during the Delivery Year. A PRD offer includes MW quantities that the seller will reduce at defined capacity market reservation prices ($/MW-day). PRD offers change the shape of the VRR Curves used in the capacity market auctions.

PRD is provided by a PJM member that represents retail customers that have the ability to reduce load in response to price. In order to be eligible as PRD, the end use customer load must be served under a dynamic retail rate or contractual arrangement linked to, or based upon, a PJM real-time LMP trigger at a substation as electrically close as practical to the applicable load. End use customer loads identified may not sell any other form of demand side management in PJM markets.

PRD must also be curtailed once PJM has declared a Performance Assessment Interval but only if the real-time LMP at the applicable location meets or exceeds the price on the submitted PRD curve at which the load has committed to curtail. The high PRD strike prices mean that PRD could avoid a performance requirement even during a PAI.

In order to commit PRD for a delivery year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction which indicates the Nominal PRD Value in MW that the PRD Provider is willing to commit at different reservation prices expressed in ($/MW-day). Additional PRD may participate in the Third Incremental Auction only if the LDA final peak load forecast for the delivery year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

Unlike other capacity resources, once committed, PRD may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. A PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally. The PRD Provider will receive a Daily PRD Credit ($/MW-day) during the Delivery Year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the Delivery Year. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and has cleared auctions for the 2021/2022 Delivery Year and 2022/2023 Delivery Year.[61] Table 6-16 shows the Nominated MW of Price Responsive Demand for the 2021/2022 and 2022/2023 Delivery Years.

Table 6-16 Nominated MW of Price Responsive Demand 2021/2022 and 2022/2023 Delivery Years

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2022/2023	230.0	230.0	40.0	190.0	19.6	110.0	80.0
2021/2022	510.0	510.0	75.0	435.0	35.7	195.0	240.0

PRD is included on the supply side of RPM auctions. The cleared PRD is credited the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs by inclusion in the RPM net load price A PRD Provider receives a PRD Credit for each approved Price Responsive Demand registration on a given day. PRD Credits are determined as:[62]

> *PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) plus,*
>
> *(Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].*

Effective with the 2022/2023 Delivery Year, the factor equal to (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) is eliminated in the calculation of the PRD Credit.

Table 6-17 shows the PRD Credits for the 2020/2021 and 2021/2022 Delivery Years.

Table 6-17 PRD Credits for 2020/2021 and 2021/2022 Delivery Years

Delivery Year	PRD Credit
2021/2022	$38,282,769.14
2020/2021	$23,649,865.05

61 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

62 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 52 (Feb. 24, 2022).

A PRD Provider with a daily commitment compliance shortfall in a subzone/zone for RPM or FRR is assessed a Daily PRD Commitment Compliance Penalty. The Daily PRD Commitment Compliance Penalty is determined as:

*PRD Commitment Compliance Penalty = MW shortfall in the Sub-zone/Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate*

The revenue collected from assessment of the PRD Commitment Compliance Penalty is distributed to all entities that committed Capacity Resources in the RPM Auctions for the relevant delivery year, based on each entity's prorata share of daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

Table 6-18 shows the PRD Commitment Compliance Penalties for the 2020/2021 and 2021/2022 Delivery Years

Table 6-18 PRD Commitment Compliance Penalties for 2020/2021 and 2021/2022 Delivery Years

Delivery Year	Charges
2021/2022	$395,319.95
2020/2021	$0

PRD committed in RPM for the current delivery year bids in the PJM Energy Market. PRD Curves may be submitted by PRD Providers in the PJM Energy Market by 1100 at the closing of the day-ahead bid period. PRD Curves submitted by PRD Providers are identified in the day-ahead market software and user interface. PRD bids are modeled in the real-time energy market only, and are modeled in the real-time dispatch algorithms. PRD curves are not modeled in the day-ahead market clearing process. PRD Curves in the energy market are modeled in the real-time dispatch algorithms and can set Real-time LMP. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to real-time LMPs for the PRD Curves that are submitted. The maximum bid price of the PRD Curve is the applicable energy market offer cap. When PRD sellers offer at the cap, they limit the number of times that PRD is called on to respond.

The PRD rules fall short of defining an effective and efficient product that is aligned with the definition of a capacity resource.[63] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[64] PJM's final filing adopted the MMU's recommendation to exclude the use of Winter Peak Load (WPL) when calculating the nominated MW for PRD resources used to satisfy RPM commitments. Load is allocated capacity obligations based on the annual peak load within PJM. The amount of capacity allocated to load is a function solely of summer coincident peak demand and is unaffected by winter demand. Use of the WPL to calculate the nominated MW for PRD resources to satisfy RPM commitments, would incorrectly restrict PRD to less than the total capacity the customer is required to buy. PJM's adoption of the MMU recommendation correctly values PRD nominated MW. FERC required and PJM's filing also adopted the MMU's recommendation that PRD should be eligible for bonus performance payments during Performance Assessment Intervals (PAI) only when PRD resources respond above their nominated MW value. Allowing PRD resources to collect bonus payments at times when they are not even required to meet their basic obligation would be inconsistent with the basic CP construct as it applies to all other CP resources.[65]

PJM's filing still fell short of completely aligning PRD with the definition of capacity. PRD resources do not have to respond during a PAI if the PRD's trigger price is above LMP during the PAI. All other CP resources have the obligation to perform during a PAI, regardless of the real-time LMP, subject to instructions from PJM. PRD should be held to the same standard during a PAI event. 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.

Economic Load Response Program

The Economic Load Response Program is for demand response customers that offer into the day-ahead or real-time energy market. The estimated load

63 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
64 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).
65 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

Table 6-19 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2021, through September 30, 2022. The ownership of economic demand response resources was highly concentrated in 2021 and the first nine months of 2022.[66] Table 6-19 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. In the first nine months of 2022, 91.0 percent of all economic DR reported reductions and 89.1 percent of economic DR revenue were attributable to the four largest CSPs. The HHI for economic demand response was highly concentrated for the first nine months of 2022. The HHI for economic demand response in the first nine months of 2022 decreased by 923 from 8674 for the first nine months of 2021 to 7751 for the first nine months of 2022.

Table 6-19 Average hourly MWh HHI and market concentration in the economic program: January 2021 through September 2022[67]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2021	2022	Percent Change	2021	2022	Change in Percent	2021	2022	Change in Percent
Jan	9305	7182	(22.8%)	99.3%	99.8%	0.5%	98.6%	99.8%	1.2%
Feb	7601	7474	(1.7%)	92.8%	98.8%	6.1%	90.5%	99.0%	8.5%
Mar	9700	8927	(8.0%)	100.0%	97.6%	(2.4%)	100.0%	97.8%	(2.2%)
Apr	9339	7310	(21.7%)	100.0%	89.8%	(10.2%)	100.0%	88.3%	(11.7%)
May	9732	7003	(28.0%)	100.0%	96.5%	(3.5%)	100.0%	96.8%	(3.2%)
Jun	8087	7147	(11.6%)	88.6%	93.5%	5.0%	83.6%	93.1%	9.4%
Jul	8238	7500	(9.0%)	91.5%	94.9%	3.4%	90.1%	94.1%	4.0%
Aug	8121	7309	(10.0%)	89.1%	94.5%	5.4%	90.1%	89.6%	(0.5%)
Sep	7940	9907	24.8%	95.3%			96.3%		
Oct	9400			96.9%			96.1%		
Nov	8121			100.0%			100.0%		
Dec	7745			100.0%			100.0%		
Total	8526	7575	(11.2%)	70.1%	91.0%	20.9%	65.2%	89.1%	23.9%

66 All HHI calculations in this section are at the parent company level.
67 September 2022 reduction and credit share values are redacted based on confidentiality rules.

Market Performance

Table 6-20 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in the first nine months of years 2010 through 2022. The average credits per MWh paid increased by $42.99 per MWh, 73.1 percent, from $58.84 per MWh in 2021 to $101.83 per MWh in 2022. The PJM real-time load-weighted average LMP in the first nine months of 2022 was $77.84 per MWh, an increase of $42.16 per MWh, 118.2 percent, over the average LMP in the first nine months of 2021. Curtailed energy for the economic program was 54,876 MWh in the first nine months of 2022, an increase of 39,405 MWh, 254.7 percent, over curtailed energy for the economic program in the first nine months of 2021. Total credits paid for the economic load response program in the first nine months of 2022 was $5,588,035, an increase of $4,677,741, 513.9 percent, over the total credits paid for the economic load response program in the first nine months of 2021.

Table 6-20 Credits paid to economic program participants: January through September, 2010 through 2022

(Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	121,381	$8,172,654	$67.33
2013	105,299	$7,387,658	$70.16
2014	118,007	$16,510,733	$139.91
2015	103,721	$7,355,263	$70.91
2016	67,516	$3,032,039	$44.91
2017	49,331	$2,167,590	$43.94
2018	44,735	$2,360,007	$52.76
2019	20,867	$860,018	$41.21
2020	8,146	$289,129	$35.49
2021	15,471	$910,294	$58.84
2022	54,876	$5,588,035	$101.83

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the emergency rules.[68] For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the day-ahead energy market, the

68 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 122 (Oct. 1, 2022).

demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[69] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 1, 2010, through September 30, 2022.

Figure 6-2 Economic program credits and MWh by month: 2010 through September 2022

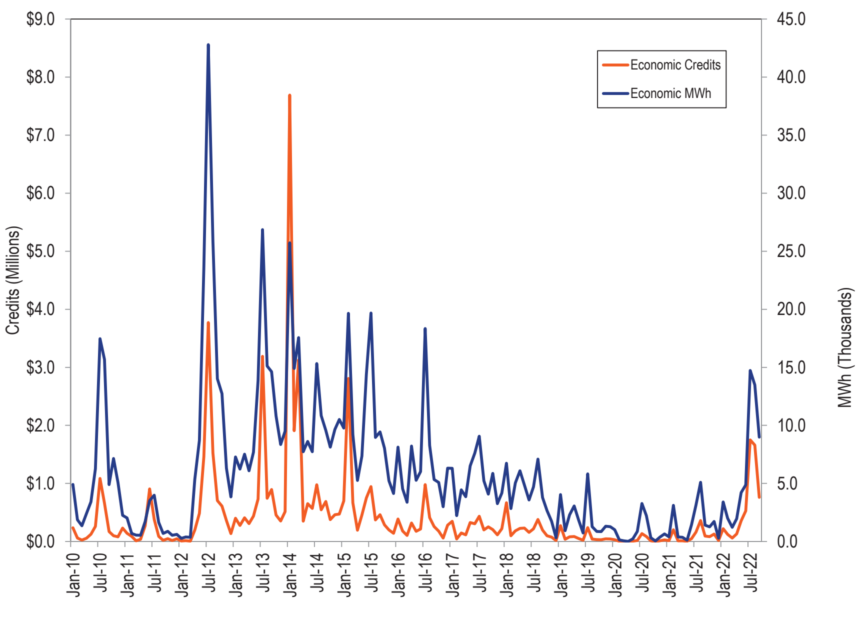


Table 6-21 shows performance for the first nine months of 2021 and 2022 in the economic program by control zone. Total reported reductions under the economic program increased by 39,405 MWh, 254.7 percent, from 15,471 MWh in the first nine months of 2021 to 54,876 MWh in the first nine months of 2022. Total revenue under the economic program 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.[70]

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[71] The zonal allocation is shown in Table 6-21.

69 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

70 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-17. Payments for Economic demand response reductions are settled monthly.

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

Table 6-21 Economic program participation by zone: January through September, 2021 and 2022

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change
AECO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$236,426.62	$369,703.75	56.4%	4,134	4,967	20.1%	$57.19	$74.43	30.2%
APS	$13,965.80	$249,700.83	1,687.9%	197	1,716	770.9%	$70.88	$145.52	105.3%
ATSI	$29,286.94	$534,289.07	1,724.3%	358	5,728	1,500.9%	$81.85	$93.27	14.0%
BGE	$50,122.22	$0.00	NA	641	0	NA	$78.18	NA	NA
COMED	$21,611.04	$62,186.19	187.8%	436	1,034	137.3%	$49.58	$60.12	21.3%
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$0.00	$3,400,648.51	NA	0	30,759	NA	NA	$110.56	NA
DOM	$10,465.15	$0.00	NA	80	0	NA	$131.56	NA	NA
DPL	$28,300.73	$0.00	NA	522	0	NA	$54.23	NA	NA
JCPL	$99,110.25	$68,436.91	(30.9%)	1,087	349	(67.9%)	$91.22	$195.95	114.8%
METED	$53,001.97	$150,257.01	183.5%	1,053	1,484	40.9%	$50.32	$101.24	101.2%
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$117,942.50	$225,517.03	91.2%	2,136	2,792	30.7%	$55.20	$80.78	46.3%
PENELEC	$40,652.25	$113,311.31	178.7%	1,342	1,559	16.2%	$30.29	$72.69	139.9%
PEPCO	$16,841.27	$0.00	NA	297	0	NA	$56.68	NA	NA
PPL	$111,579.87	$132,207.27	18.5%	1,942	409	(78.9%)	$57.47	$323.21	462.4%
PSEG	$80,987.75	$281,777.11	247.9%	1,246	4,077	227.2%	$65.00	$69.11	6.3%
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$910,294.36	$5,588,034.99	513.9%	15,471	54,876	254.7%	$58.84	$101.83	73.1%

Table 6-22 shows average reported MWh reductions and credits by hour for the first nine months of 2021 and 2022. The average LMP during Load Response is the reduction weighted average hourly DA or RT load weighted LMP during the economic load response hour. In the first nine months of 2021, 92.1 percent of the reported reductions and 93.4 percent of credits occurred in hours ending 0900 to 2100, and in the first nine months of 2022, 86.8 percent of the reported reductions and 90.1 percent of credits occurred in hours ending 0900 to 2100. The average LMP during load response increased by $50.09 per MWh, 86 percent, from $59.77 per MWh in the first nine months of 2021 to $109.84 per MWh during the first nine months of 2022.

Table 6-22 Hourly frequency distribution of economic program reported MWh reductions and credits: January through September, 2021 and 2022

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change
1 through 6	277	808	192%	$13,117	$46,937	258%	$59.04	$63.80	8%
7	116	840	625%	$5,604	$42,620	661%	$65.88	$75.43	15%
8	152	1,082	612%	$8,324	$61,181	635%	$68.55	$79.81	16%
9	387	1,355	250%	$17,349	$93,221	437%	$50.74	$77.98	54%
10	477	1,670	251%	$20,570	$125,040	508%	$48.00	$84.83	77%
11	561	2,297	309%	$24,360	$189,815	679%	$49.87	$92.85	86%
12	732	2,964	305%	$34,431	$265,269	670%	$50.10	$101.59	103%
13	829	3,541	327%	$40,881	$338,823	729%	$53.38	$107.97	102%
14	1,215	4,061	234%	$70,383	$424,110	503%	$61.14	$117.74	93%
15	1,344	4,302	220%	$79,709	$482,449	505%	$62.00	$125.52	102%
16	1,630	4,531	178%	$113,764	$545,826	380%	$67.80	$136.33	101%
17	1,930	4,737	145%	$141,718	$608,535	329%	$77.30	$149.40	93%
18	2,287	4,921	115%	$139,954	$602,783	331%	$81.55	$150.17	84%
19	1,221	4,839	296%	$83,228	$538,903	548%	$71.32	$127.98	79%
20	941	4,531	381%	$48,486	$449,655	827%	$55.22	$112.34	103%
21	703	3,890	454%	$35,560	$372,565	948%	$53.52	$105.03	96%
22	411	2,623	538%	$20,084	$245,456	1,122%	$50.88	$99.25	95%
23 through 24	259	1,882	627%	$12,772	$154,848	1,112%	$49.54	$169.05	241%
Total	15,471	54,876	255%	$910,294	$5,588,035	514%	$59.77	$109.84	86%

Table 6-23 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in the first nine months of 2021 and 2022. In the first nine months of 2022, 6.2 percent of reported MWh reductions and 10.8 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-23 Frequency distribution of economic program zonal load-weighted average LMP (By hours): January through September, 2021 and 2022

	MWh Reductions			Program Credits		
LMP	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change
$0 to $25	978	55	(94%)	$27,116	$3,134	(88%)
$25 to $50	7,525	3,776	(50%)	$355,019	$161,333	(55%)
$50 to $75	3,791	8,315	119%	$228,552	$518,827	127%
$75 to $100	1,361	16,249	1,094%	$116,277	$1,589,047	1,267%
$100 to $125	1,174	13,064	1,012%	$129,030	$1,458,439	1,030%
$125 to $150	252	6,640	2,533%	$24,137	$799,548	3,213%
$150 to $175	141	3,377	2,298%	$6,309	$455,280	7,116%
> $175	248	3,398	1,269%	$23,856	$602,428	2,425%
Total	15,471	54,876	255%	$910,294	$5,588,035	514%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-24 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. Through the first nine months of 2022, real-time loads in AEP have paid the highest Economic Load Response charges.

Table 6-24 Zonal Economic Load Response charge: January through September, 2022[72]

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$2,363	$1,072	$584	$1,407	$3,890	$6,666	$26,837	$25,864	$8,373	$77,056
AEP	$34,657	$19,970	$9,435	$21,850	$55,652	$79,966	$247,874	$234,181	$114,197	$817,780
APS	$14,187	$7,967	$3,816	$8,499	$20,820	$29,702	$95,120	$91,000	$42,758	$313,869
ATSI	$16,953	$10,017	$4,891	$11,546	$29,354	$42,716	$135,267	$127,290	$61,156	$439,190
BGE	$8,787	$4,828	$2,239	$4,966	$13,188	$20,286	$69,335	$66,045	$29,846	$219,520
COMED	$19,575	$11,690	$5,440	$10,740	$40,896	$63,466	$198,997	$177,490	$92,338	$620,631
DAY	$4,596	$2,710	$1,269	$2,987	$7,595	$11,521	$35,403	$33,789	$15,965	$115,834
DUKE	$7,009	$4,093	$1,869	$4,410	$11,876	$17,890	$57,479	$53,633	$25,579	$183,839
DUQ	$3,322	$1,894	$929	$2,265	$5,864	$9,037	$28,938	$26,399	$12,617	$91,266
DOM	$30,914	$16,916	$7,900	$18,494	$49,629	$71,868	$239,900	$226,313	$109,315	$771,250
DPL	$5,437	$2,664	$1,218	$2,552	$6,545	$10,536	$42,523	$41,781	$11,685	$124,941
EKPC	$4,225	$2,347	$971	$2,113	$5,445	$8,413	$26,751	$25,205	$12,001	$87,472
JCPLC	$5,600	$2,573	$1,446	$3,459	$9,557	$15,250	$61,900	$57,653	$21,007	$178,445
MEC	$4,311	$2,398	$1,188	$2,756	$6,772	$9,700	$33,201	$32,157	$13,976	$106,458
OVEC	$31	$19	$9	$20	$43	$53	$174	$160	$88	$596
PECO	$10,265	$5,224	$2,479	$5,848	$14,673	$22,801	$89,975	$87,045	$25,045	$263,356
PE	$4,584	$2,726	$1,331	$3,107	$7,330	$9,778	$31,912	$30,417	$14,446	$105,631
PEPCO	$7,903	$4,344	$2,039	$4,601	$12,267	$18,903	$63,400	$59,821	$27,649	$200,928
PPL	$11,815	$6,148	$3,110	$7,261	$17,175	$23,988	$82,263	$78,957	$35,092	$265,808
PSEG	$10,543	$5,553	$2,834	$6,882	$18,339	$27,971	$105,556	$100,002	$37,458	$315,138
REC	$331	$187	$93	$224	$650	$1,039	$4,030	$3,816	$1,494	$11,864
Exports	$12,173	$8,063	$3,775	$5,523	$19,127	$24,651	$72,802	$82,129	$48,921	$277,164
Total	$219,580	$123,402	$58,865	$131,511	$356,688	$526,201	$1,749,637	$1,661,147	$761,005	$5,588,035

72 Load response charges were downloaded as of Oct 6, 2022 and may change as a result of continued PJM billing updates.

Table 6-25 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in the first nine months of 2022.

Table 6-25 Zonal economic load response charge per GWh of load and exports: January through September, 2022

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	$2.764	$1.532	$0.841	$2.233	$5.199	$7.472	$22.460	$21.845	$9.901	$8.250
AEP	$2.831	$1.918	$0.921	$2.349	$5.706	$7.497	$21.560	$20.834	$11.734	$8.372
APS	$2.858	$1.923	$0.937	$2.367	$5.721	$7.564	$22.096	$21.249	$11.833	$8.505
ATSI	$2.819	$1.897	$0.916	$2.390	$5.766	$7.541	$21.978	$20.850	$11.793	$8.439
BGE	$2.874	$1.961	$0.943	$2.402	$5.757	$7.830	$22.578	$21.713	$12.450	$8.723
COMED	$2.326	$1.599	$0.750	$1.620	$5.508	$7.577	$21.714	$19.900	$12.255	$8.139
DAY	$2.835	$1.938	$0.928	$2.398	$5.808	$7.724	$22.110	$21.325	$12.010	$8.564
DUKE	$2.855	$1.943	$0.921	$2.354	$5.742	$7.634	$21.911	$21.287	$12.143	$8.532
DUQ	$2.797	$1.897	$0.923	$2.374	$5.731	$7.610	$21.854	$20.785	$11.811	$8.420
DOM	$2.865	$1.945	$0.928	$2.375	$5.722	$7.548	$21.886	$21.191	$12.115	$8.508
DPL	$2.861	$1.755	$0.841	$2.098	$4.834	$6.851	$22.112	$22.042	$8.101	$7.944
EKPC	$2.920	$2.005	$0.918	$2.276	$5.768	$7.801	$22.395	$21.706	$12.310	$8.678
JCPLC	$2.836	$1.575	$0.891	$2.420	$5.780	$8.026	$23.898	$22.726	$11.749	$8.878
MEC	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
OVEC	$2.692	$1.823	$0.875	$2.209	$5.251	$6.509	$19.032	$18.274	$10.021	$7.409
PECO	$2.811	$1.720	$0.828	$2.194	$5.002	$6.985	$22.080	$21.508	$8.195	$7.925
PE	$2.846	$1.915	$0.935	$2.418	$5.708	$7.268	$21.575	$20.623	$11.352	$8.293
PEPCO	$2.882	$1.976	$0.952	$2.417	$5.739	$7.779	$22.241	$21.487	$12.306	$8.642
PPL	$2.849	$1.760	$0.906	$2.416	$5.667	$7.493	$21.970	$21.099	$11.565	$8.414
PSEG	$2.819	$1.743	$0.879	$2.399	$5.642	$7.565	$22.271	$21.304	$10.743	$8.374
REC	$2.826	$1.870	$0.906	$2.413	$5.722	$8.095	$24.106	$22.785	$12.706	$9.048
Exports	$2.501	$1.779	$0.850	$2.267	$5.607	$6.430	$18.163	$16.804	$0.000	$6.044
Monthly Average	$2.667	$1.749	$0.854	$2.199	$5.335	$7.127	$20.909	$20.061	$10.322	$7.914

Table 6-26 shows the monthly day-ahead and real-time Economic Load Response charges for 2021 and the first nine months of 2022. The day-ahead Economic Load Response charges increased by $4.1 million, 675.4 percent, from $613.0 thousand in the first nine months of 2021 to $4.8 million in the first nine months of 2022. The months of July through September accounted for 3.5 million or 84 percent of this increase. The real-time Economic Load Response charges increased $537.1 thousand, 180.7 percent, from $297.3 thousand in the first nine months of 2021 to $834.4 thousand in first nine months of 2022.[73]

Table 6-26 Monthly day-ahead and real-time economic load response charge: January 2021 through September 2022

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2021	2022	Percent Change	2021	2022	Percent Change
Jan	$14,204	$208,026	1,364.6%	$648	$11,554	1,684.4%
Feb	$160,337	$59,319	(63.0%)	$42,474	$64,082	50.9%
Mar	$10,287	$17,440	69.5%	$136	$41,425	30,292.2%
Apr	$8,332	$100,975	1,111.9%	$3,766	$30,536	710.8%
May	$2,060	$264,451	12,734.9%	$2,062	$92,237	4,373.4%
Jun	$37,802	$247,738	555.4%	$11,412	$278,463	2,340.2%
Jul	$120,863	$1,574,857	1,203.0%	$41,559	$174,780	320.6%
Aug	$178,881	$1,520,387	749.9%	$183,186	$140,760	(23.2%)
Sep	$80,272	$760,461	847.4%	$12,014	$544	(95.5%)
Oct	$64,685			$18,381		
Nov	$115,233			$13,833		
Dec	$12,238			$3,373		
Total	$805,194	$4,753,655	490.4%	$332,843	$834,380	150.7%

Table 6-27 shows registered sites and MW for the last day of each month for the period January 1, 2018, through September 30, 2022. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations increased by 21, 7.1 percent, from 302 in the first nine months of 2021 to 323 in the first nine months of 2022. Average monthly registered MW increased by 562 MW, 31.0 percent, from 1,814 MW in the first nine months of 2021 to 2,376 MW in the first nine months of 2022.

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 87 economic registrations and 87 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,284 nominated economic MW and 1,079 nominated capacity MW in the emergency program that share the same location IDs in both programs.

73 Load response charges were downloaded as of October 6, 2022, and may change as a result of continued PJM billing updates.

Table 6-27 Economic program registrations on the last day of the month: 2018 through September 2022[74]

	2018		2019		2020		2021		2022	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	537	2,570	374	2,651	377	2,909	277	1,495	323	2,232
Feb	537	2,628	370	2,640	382	2,912	275	1,503	323	2,255
Mar	519	2,641	378	2,648	380	2,941	284	1,514	330	2,376
Apr	501	2,624	366	2,594	350	2,917	293	1,538	330	2,381
May	471	2,615	372	3,193	308	2,824	319	1,658	326	2,376
Jun	397	2,576	370	2,768	285	1,418	313	2,136	315	2,323
Jul	374	2,591	376	2,899	283	1,453	312	2,105	310	2,412
Aug	382	2,609	360	2,885	292	1,482	322	2,122	319	2,458
Sep	378	2,580	368	2,954	297	1,566	322	2,256	334	2,575
Oct	382	2,584	375	2,909	275	1,361	332	2,267		
Nov	381	2,581	379	3,051	280	1,375	333	2,270		
Dec	392	2,671	383	3,070	282	1,327	320	2,256		
Avg	438	2,606	373	2,855	316	2,040	309	1,927	323	2,376

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch up to the amount of MW registered in the program, but are not required to offer any MW. Table 6-28 shows the sum of maximum economic MW dispatched by registration each month from January 1, 2010, through September 30, 2022. The monthly maximum is the sum of each registration's monthly noncoincident maximum dispatched MW and annual maximum is the sum of each registration's annual noncoincident maximum dispatched MW. The monthly maximum dispatched MW increased in six of the first nine months of 2022 as compared to 2021.[75]

Table 6-28 Sum of maximum MW reported reductions for all registrations per month: 2010 through September 2022

	Sum of Peak MW Reductions for all Registrations per Month												
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Jan	183	132	110	193	446	169	139	123	142	88	28	21	34
Feb	121	89	101	119	307	336	128	83	70	58	11	86	34
Mar	115	81	72	127	369	198	120	111	71	38	12	20	30
Apr	111	80	108	133	146	143	118	54	71	41	3	22	43
May	172	98	143	192	151	161	131	169	70	22	12	9	53
Jun	209	561	954	433	483	833	121	240	105	26	38	125	110
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	770	135	134	151
Aug	794	161	952	497	358	272	249	141	581	33	99	827	141
Sep	276	84	451	530	795	816	263	140	112	76	31	35	51
Oct	118	81	242	168	214	136	150	88	69	29	9	31	
Nov	111	86	165	155	166	127	116	81	54	35	12	31	
Dec	114	88	98	168	155	122	147	83	11	31	14	19	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196	921	191.5

74 Data for years 2010 through 2017 are available in the *2017 State of the Market Report for PJM*.
75 Maximum MW reductions were downloaded on Oct 6, 2022, and may change as a result of continued PJM billing updates.

Table 6-29 shows total settlements submitted for the first nine months of years 2010 through 2022. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-29 Settlements submitted in the economic program: January through September, 2010 through 2022

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Number of Settlements	3,367	703	5,334	2,358	2,425	1,851	1,524	1,417	1,263	875	458	678	1,524

Table 6-30 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the first nine months of years 2010 through 2022. The number of active participants decreased by 7, 20.0 percent, from 35 in the first nine months of 2021 to 28 in the first nine months of 2022. All participants must be registered through a CSP.

Table 6-30 Participants and CSPs submitting settlements in the economic program by year: January through September, 2010 through 2022

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Active CSPs	16	15	22	20	16	18	12	13	13	12	10	11	9
Active Participants	257	203	428	273	154	114	58	72	58	51	29	35	28

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[76] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[77] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load.

PJM calculates the NBT price threshold by first retrieving generation offers from the same month of the prior calendar year for which the calculation is being performed. PJM then adjusts a portion of each prior year offer, representing the typical share of fuel costs in energy offers in the PJM Region, for changes in fuel prices based on the ratio of the reference month spot fuel price to the study month forward fuel price. To accomplish this adjustment, the ratio of forward prices for the study month to the spot fuel prices for the reference month is used as a scaling factor. If the forward price for the study month was $7.08 and the spot fuel

76 157 FERC ¶ 61,115 at P 139 (2016).
77 *Id.* at 8.

price from the reference month was $6.75, then the ratio is 1.05. The offers of generation units are then adjusted by this scaling factor. The price of fuel typically represents 80 to 90 percent of a generator's offer with the remainder being variable operations and maintenance costs. Where generators offer multiple points on a curve, each point on the curve is adjusted in this manner. The offers are then combined to create daily supply curves for each day in the period. The daily curves are then averaged to form an average supply curve for the study month. PJM then uses a non-linear least squares estimation technique to determine an equation that approximates and smooths this average supply curve. The NBT threshold price is the price at the point where the price elasticity of supply is equal to 1.0 for this estimated supply curve equation.[78] PJM publishes the details of the equation and parameters each month along with the NBT results.

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions.[79]

Table 6-31 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when FERC Order No. 745 was implemented in PJM, through September 2022. The historical test was used as justification for the method of calculating the NBT for future months. From 2012 through 2021, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh one time, in March 2014 when the NBT threshold price was $34.93. The NBT threshold price has exceeded the lowest historical test result of $34.07 per MWh in seven of the first nine months of 2022. In 2022, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in February and April through September 2022 when the NBT threshold price was $34.59, $35.14, $42.94, $44.29, $48.67, $44.08 and $55.39 respectively.

Table 6-31 Net benefits test threshold prices: August 2010 through September 2022

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)										
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11	$26.93
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70	$34.59
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82	$30.00
Apr		$36.76	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47	$35.14
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01	$14.69	$21.40	$42.94
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35	$44.29
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59	$48.67
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52	$44.08
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06	$55.39
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20	
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85	
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.64	$16.87	$23.03	$40.23

78 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 122 (Oct. 1, 2022).

79 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 122 (Oct. 1, 2022).

Table 6-32 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price.[80] In the first nine months of 2022, the highest zonal LMP in PJM was higher than the NBT threshold price 6,324 hours out of 6,551 hours, or 96.5 percent of all hours. Reductions occurred in 3,946 hours, 62.4 percent, of those 6,324 hours in the first nine months of 2022. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2021, through September 30, 2022. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reported reductions occurred in none of the hours in which LMP was below the NBT threshold price in 2021, and none of the hours in which LMP was below the NBT threshold price in the first nine months of 2022.

Table 6-32 Hours with price higher than NBT and economic load response occurrences in those hours: 2021 through September 2022

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2021	2022	2021	2022	Percent Change	2021	2022	Percentage Change
Jan	744	744	741	724	(2.3%)	11.9%	70.3%	58.4%
Feb	672	672	667	663	(0.6%)	50.2%	47.8%	(2.4%)
Mar	743	743	698	742	6.3%	12.5%	55.3%	42.8%
Apr	720	720	618	720	16.5%	21.4%	66.4%	45.0%
May	744	744	636	744	17.0%	24.4%	82.9%	58.6%
Jun	720	720	592	684	15.5%	44.9%	71.1%	26.1%
Jul	744	744	727	680	(6.5%)	49.1%	71.3%	22.2%
Aug	744	744	744	744	0.0%	54.7%	56.9%	2.2%
Sep	720	720	720	623	(13.5%)	43.2%	35.5%	(7.7%)
Oct	744		744			48.5%		
Nov	721		721			52.6%		
Dec	744		610			25.2%		
Total	8,760	6,551	8,218	6,324	(23.0%)	36.9%	62.4%	25.5%

80 The MWh for demand resources were downloaded as of October 7, 2022, and may change as a result of continued PJM billing updates.

Energy Efficiency

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not produce power, but reduce power consumption. The Nominated MW for EE resources are not measured, although they could be, but a calculated value based on a set of largely unverified and unverifiable assumptions. An installed EE resource may participate as a capacity resource for up to four consecutive delivery years.[81]

Prescriptive energy efficiency MW have an assumed savings calculated based on an assumed installation rate and the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM Capacity Market is prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement or verification but instead relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.[82] There is no evidence that the programs result in changed behavior or increases in savings.

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.[83] EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets because it reduces energy and capacity use and therefore customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original logic for the inclusion of EE in the capacity market is no longer correct. While EE does not affect the clearing price when the EE addback is done correctly, customers do pay for the cleared

81 PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 52 (Feb. 24, 2022).
82 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 05 (Sep. 21, 2019).
83 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).

quantity of EE at market clearing prices. These direct payments to EE in the capacity market are an overpayment by customers.

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. The purpose of the registration system is to prevent duplicative claims to capacity rights and to document installation periods of energy efficiency to verify eligibility for continued participation measures. Energy Efficiency projects should be clearly identified by retail customer account, year of project installation and a description of the Energy Efficiency project. Energy Efficiency Resources are eligible to participate as supply in RPM for up to four years following their installation. Beyond the fourth year, the energy savings benefit of an Energy Efficiency project is incorporated into the load forecast used for RPM Auctions.

A registration system would also serve the benefit of preventing multiple Energy Efficiency Providers from claiming capacity rights to the same project. The Energy Efficiency Resource Provider offering an Energy Efficiency Resource as a Capacity Resource into RPM must demonstrate to PJM that it has the legal authority to claim the demand associated with such Energy Efficiency Resource.[84] The Energy Efficiency Resource Provider can satisfy this requirement by submitting to PJM a written sworn, notarized statement of one of its corporate officers certifying that the Energy Efficiency Resource Provider has the legal authority to claim the demand reduction associated with the EE installations that constitute the Energy Efficiency Resource for the applicable Delivery Year. The Energy Efficiency Resource Provider can also satisfy this requirement by including a statement in their Energy Efficiency Post-Installation Measurement & Verification Report that they have legal authority to claim the demand reduction associated with the EE installations that constitute the Energy Efficiency Resource for the applicable delivery year. 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. These eligibility requirements should specifically define the conditions under which an Energy Efficiency Resource Provider may claim the capacity rights to Energy Efficiency installations as well as evidentiary requirements such as signed contracts with their customers conferring such rights. Energy efficiency resources are included in the PJM Capacity Market. Table 6-33 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2011/2012 through 2022/2023 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[85] Only Kentucky has been authorized by the Commission.[86] The total MW of energy efficiency resources committed increased by 19.3 percent from 4,806.2 MW in the 2021/2022 Delivery Year to 5,734.8 MW in the 2022/2023 Delivery Year.[87]

Table 6-33 Energy efficiency resources (MW): Delivery Years 2011/2012 through 2022/2023

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE Percent Cleared
2011/2012	76.4	134,139.6	0.1%
2012/2013	666.1	141,061.8	0.5%
2013/2014	904.2	159,830.5	0.6%
2014/2015	1,077.7	161,092.4	0.7%
2015/2016	1,189.6	173,487.4	0.7%
2016/2017	1,723.2	179,749.0	1.0%
2017/2018	1,922.3	180,590.3	1.1%
2018/2019	2,296.3	175,957.4	1.3%
2019/2020	2,528.5	177,040.6	1.4%
2020/2021	3,569.5	173,688.5	2.1%
2021/2022	4,806.2	174,713.0	2.8%
2022/2023	5,734.8	150,465.2	3.8%

84 EE Post-Installation Measurement & Verification Report Template, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/ee-post-installation-mv-report-template.ashx> (*Accessed Aug. 5, 2022*).

85 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

86 FERC made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE. FERC explained that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 66 (2017).

87 See the *2021 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

Distributed Energy Resources

Distributed Energy Resources (DER) generally include small scale generation directly connected to the grid, generation connected to distribution level facilities, behind the meter generation and some energy storage facilities. FERC issued Order No. 2222 on September 17, 2020, with the goal of removing barriers for small distributed resources to enter the wholesale market by allowing them to aggregate in order to encourage competition.[88]

PJM made a compliance filing at FERC on February 1, 2022, and the MMU provided comments on April 1, 2022, April 18, 2022 and May 19, 2022.[89] [90] FERC requested additional information from PJM on May 18, 2022, to which PJM submitted its response on July 7, 2022.[91] [92] Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets.

The EDCs' dual role as the distribution system operator and as a DER aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is structurally not competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent.

The PJM market is a nodal market because nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed.

Under the proposed DER rules, favorable treatment of resources that participate in the DER aggregation model over other resources includes: exemption from the PJM interconnection process; no must offer requirement in the capacity market; exemption from the RPM Minimum Offer Price Rule ("MOPR") when co-located with retail load; exemption from the market seller offer cap ("MSOC") when co-located with retail load; and ability to reduce load and inject power into the grid at the same time. These exemptions from basic market rules are not appropriate even for small participants and are not necessary to facilitate participation. But large DERs that are already capable of participating in the PJM markets under the current rules should not be given the option to exploit the new rules. PJM proposed the maximum size requirement of 5 MW for component DERs but did not propose a maximum size requirement for DER Aggregation Resources.[93] This loophole would allow larger DERs to divide one larger resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource. To avoid this loophole, there should be a maximum size requirement on the DER Aggregation Resource.

DERs should not be exempt from market power mitigation. Small resources can and do have market power. There is no downside to having market power mitigation rules. If they are not triggered, then there is no issue. But there is a downside to not having market power mitigation rules. The February 1st Filing legitimately requires DER aggregation resources to submit cost-based offers but fails to address offer parameter mitigation. The February 1st Filing exempts most DER aggregation resources from the capacity MSOC and the MOPR. Finally, the February 1st Filing does not clarify how DER aggregation resources will satisfy the day-ahead energy market must offer requirement.

Demand response resources are not the same as DER aggregation resources. Demand response resources cannot inject energy into the grid while DER aggregation resources can; demand response resources are modeled as load reduction while DER aggregation resources should be modeled as generation. The rules for demand response resources and the rules for DER aggregation resources should not be the same because the two resource types function very differently in the PJM market.

No resource should be paid more than once for its services. In most of the states in PJM, net energy metering means paying for resources on the distribution system at the full retail rate. As a result of the fact that retail rates include all

88 172 FERC ¶ 61,247 (2020) PP 6-7.
89 Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022).
90 Comments of the Independent Market Monitor for PJM, Docket No. ER22-962 (April 1, 2022); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER22-962 (April 18, 2022); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER22-962 (May 19, 2022).
91 Letter requesting PJM Interconnection, L.L.C. to file additional information within 30 days re the tariff revisions etc., Docket No. ER22-962 (May 18, 2022).
92 Response to May 18, 2022 Request for Additional Information, Docket No. ER22-962 (July 7, 2022).
93 Individual DERs in DER Aggregation Resources. See definitions in the February 1st Filing.

wholesale market costs, there is no way to avoid double compensation for net energy metering resources if they were to participate directly in any of the wholesale markets. The February 1st Filing proposes to allow a component DER that is also a net energy metering resource to participate in the PJM ancillary services markets while not allowing its participation in the capacity or the energy markets. Net energy metering resources should not be allowed to participate in any PJM wholesale market, including the ancillary services markets, when the retail rate paid to those resources includes ancillary services cost.

Peak Shaving Adjustment

Peak Shaving Adjustment (PSA) provides an alternative means for demand response to participate in the Reliability Pricing Model (RPM). Rather than being on the supply side of the capacity market, a PSA participates on the demand side through a modified peak load forecast for the zone in which the Peak Shaving Adjustment resources are located. The peak shaving adjusted load forecast is included in the VRR curve. But the resultant reduction in capacity obligation is socialized across all loads in the zone rather than directly benefitting the resources providing the Peak Shaving Adjustment.[94] This eliminates the incentive for individual customers to participate in peak shaving. The solution is in a retail rate design that directly assigns the benefits of peak shaving to individual customers. The retail rate design is within the authority of state regulators and not in the wholesale markets. Not surprisingly, although PSA was first available for inclusion in the revised March 2016 PJM Load Forecast Report, PJM has not yet approved any PSA for use in a load forecast.

A PSA plan must include: the basis for the planned reductions; a THI trigger for interruption; the duration of the interruption in hours; the MW value of the curtailment; the months of the offer; all historical addbacks for the nominated programs.[95] Any resource selling a PSA must reduce load on any day in which its trigger is met or exceeded. The trigger is based on the actual maximum daily temperature humidity index (THI) for the relevant PJM zone. When the trigger is met, the PSA must comply with its defined offer parameters including number of hours of interruption. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment value in future delivery years. Performance is measured based on the aggregated Customer Baseline (CBL). PJM applies a three year rolling average of the annual peak shaving performance ratings to the program's total participating MW in order to determine its peak shaving adjustment.

Performance Assessment Event – AEP_Marion Subzone

On June 14, 15 and 16, 2022, PJM dispatched Pre-Emergency and Emergency DR resources in the Columbus, Ohio area of the AEP Zone defined as the AEP_MARION Load Management subzone. These actions triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action area for each applicable five minute interval.[96]

On June 14, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1550 EPT and ended on June 14, 2022 at 2200 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1620 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1650 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1750 EPT.

Table 6-34 Load Management Reduction Action Event times for June 14, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30min)	1550	1620	2200
Emergency and Pre-Emergency	Short (60 min)	1550	1650	2200
Emergency and Pre-Emergency	Long (120 min)	1550	1750	2200

94 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).
95 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 35 (December 31, 2021).
96 OATT, Attachment DD § 10A

On June 15, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1050 EPT and ended on June 15, 2022 at 2200 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1120 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1150 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1250 EPT.

Table 6-35 Load Management Reduction Action Event times for June 15, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30min)	1050	1120	2200
Emergency and Pre-Emergency	Short (60 min)	1050	1150	2200
Emergency and Pre-Emergency	Long (120 min)	1050	1250	2200

On June 16, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1230 EPT and ended on June 16, 2022 at 1700 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1300 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1330 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1430 EPT.

Table 6-36 Load Management Reduction Action Event times for June 16, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30min)	1230	1300	1700
Emergency and Pre-Emergency	Short (60 min)	1230	1330	1700
Emergency and Pre-Emergency	Long (120 min)	1230	1430	1700

Performance Shortfalls

Nonperformance is measured by comparing a resource's actual performance to their expected performance. The expected performance of a DR resource is its CP commitment in ICAP terms. The actual performance of a resource is defined as the output of the resource during the event, including both energy and ancillary services. The energy output is the metered output of the resource. Ancillary services are determined as the real-time regulation or reserves on the resource. Accounting for ancillary services ensures the actual performance reflects the resource's performance up to its economic basepoint, even if off that dispatch point in order to provide the ancillary services.

The expected and actual performance for DR resources are calculated as:[97]

Expected Performance = CP Capacity Commitment (ICAP)

Actual Performance = Load Reduction + Regulation/Reserve Assignment

If a resource's expected performance is greater than the actual performance, the resource will be assessed a nonperformance penalty.

Nonperformance Charges

Nonperformance charge rates are calculated on a modeled LDA basis for the relevant delivery year. The nonperformance charge rate for a specific resource is based on the Net CONE expressed in $/MW-day in ICAP for the LDA in which the resource is modeled and is calculated as:[98]

Nonperformance Charge Rate ($/MW-5-Minute Interval) = Net CONE x Number of Days in Delivery Year / 30 Hours / 12 Intervals

The applicable charge rate for the June 2022 PAI for those resources modeled in the AEP Zone (Rest of RTO LDA) for the 2022/2023 Delivery Year is shown in Table 6-37.[99]

Table 6-37 Nonperformance Charge Rate

Zone	LDA	Net CONE (ICAP)	Charge Rate
AEP	RTO	$247.26	$250.69

97 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 52 (Feb. 24, 2022).
98 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 52 (Feb. 24, 2022).
99 PJM, Planning Period Parameters for Base Residual Auction, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-planning-period-parameters-for-base-residual-auction.ashx> (Accessed Oct 6, 2022).

This charge rate is multiplied by the performance shortfall in each PAI to determine the nonperformance financial penalty for committed CP resources. The nonperformance charge is calculated as:[100]

*Nonperformance Charge = Performance Shortfall MW * Nonperformance Charge Rate*

Table 6-38 Nonperformance Charges

Day	Avg Shortfall (MW/Interval)	Charges
June 14, 2022	5.9	$99,787.16
June 15, 2022	18.4	$590,567.72
June 16, 2022	35.1	$422,337.72
Total		$1,112,692.60

Bonus Performance

A resource with actual performance above its expected performance is assigned a share of the collected nonperformance charge revenues as a bonus performance credit. When calculating bonus megawatts, the actual performance for a dispatchable resource is capped at the megawatt level at which such resource was scheduled and dispatched by PJM during the performance assessment event.

The expected and actual performance calculations for bonus megawatt evaluations for load DR is:

Expected Performance = CP Capacity Commitment (ICAP)

Actual Performance = Load Reduction + Reserve/Regulation Assignment

Table 6-39 Bonus Performance Credits

Day	Avg Bonus (MW/Interval)	Credits
June 14, 2022	11.0	$99,787.16
June 15, 2022	13.3	$590,567.72
June 16, 2022	6.0	$422,337.72
Total		$1,112,692.60

Settlements Timeline

Nonperformance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year. Monthly charges and credits are billed by dividing the total dollar amount due or owed by the number of months remaining in the delivery year.

For the June 2022 performance assessment event, charges and credits were first billed starting in the September 2022 monthly bill, issued in October, and continue through the May 2023 monthly bill.

Emergency Action Area

The Emergency Action area for the June 14-16, 2022 performance assessment events, the AEP_MARION Load Management subzone, is defined by the zip codes shown in Table 6-40.[101]

100 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 52 (Feb. 24, 2022).

101 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed June 14, 2022).

Table 6-40 AEP_Marion Subzone Zip Codes

Zone	Subzone	Zip code
AEP	MARION	43015
AEP	MARION	43215
AEP	MARION	43125
AEP	MARION	43210
AEP	MARION	43207
AEP	MARION	43228
AEP	MARION	43213
AEP	MARION	43230
AEP	MARION	43085
AEP	MARION	43054
AEP	MARION	43219
AEP	MARION	43229
AEP	MARION	43201
AEP	MARION	43123
AEP	MARION	43205
AEP	MARION	43081
AEP	MARION	43146
AEP	MARION	43035
AEP	MARION	43082
AEP	MARION	43016
AEP	MARION	43026
AEP	MARION	43017
AEP	MARION	43240
AEP	MARION	43204
AEP	MARION	43004
AEP	MARION	43221
AEP	MARION	43209
AEP	MARION	43065
AEP	MARION	43068
AEP	MARION	43231
AEP	MARION	43064
AEP	MARION	43235
AEP	MARION	43220
AEP	MARION	43224
AEP	MARION	43202
AEP	MARION	43223
AEP	MARION	43212
AEP	MARION	43214
AEP	MARION	43232
AEP	MARION	43222
AEP	MARION	43162
AEP	MARION	43227
AEP	MARION	43211
AEP	MARION	43110

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units.

Overview

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 NO_x 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.

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.)

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.

Net Revenue

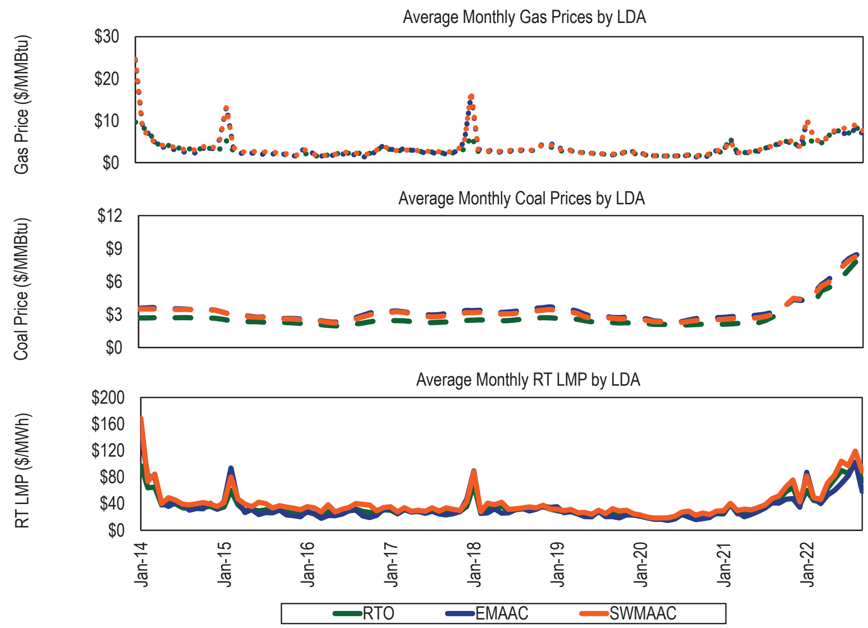
When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services and capability, less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[1] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. PJM real-time energy market prices increased significantly in the first nine months of 2022. 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. Eastern gas prices and coal prices increased in the first nine months of 2022 compared to the first nine months of 2021. Gas price volatility increased and gas price differences among regions increased. The price of eastern natural gas was 121.2 percent higher and the price of western natural gas was 46.3 percent higher; the price of Northern Appalachian coal was 187.5 percent higher; the price of Central Appalachian coal was 138.6 percent higher; and the price of Powder River Basin coal was 45.5 percent higher (Figure 7-1).

1 Avoidable costs are sometimes referred to as going forward costs.

Figure 7-1 Energy market net revenue factor trends: 2014 through September 2022



Spark Spreads and Dark Spreads

The spark or dark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas and the dark spread compares power prices to the cost of coal. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

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.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spark and dark spreads ($/MWh)

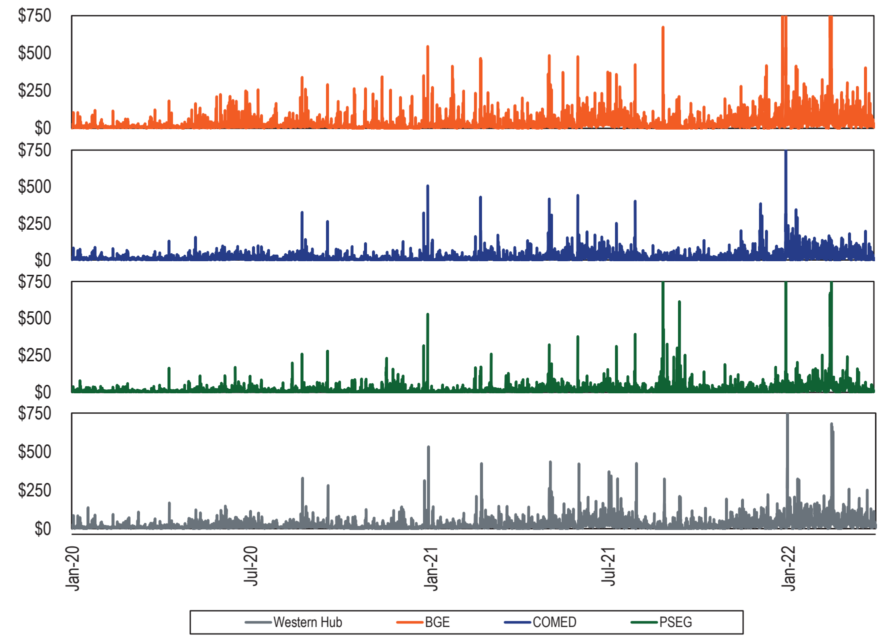
	BGE		COMED		PSEG		Western Hub	
Jan-Sep	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2021	$23.90	$23.41	$4.69	$13.52	$12.66	$7.87	$17.29	$16.66
2022	$54.05	$44.17	$30.93	$46.66	$27.31	$15.62	$38.20	$28.72

Table 7-2 Peak hour spark and dark spread standard deviation ($/MWh)

	BGE		COMED		PSEG		Western Hub	
Jan-Sep	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2021	$40.2	$40.9	$87.5	$30.6	$23.3	$25.6	$28.8	$30.3
2022	$106.4	$104.7	$59.0	$62.6	$77.5	$79.4	$80.7	$78.5

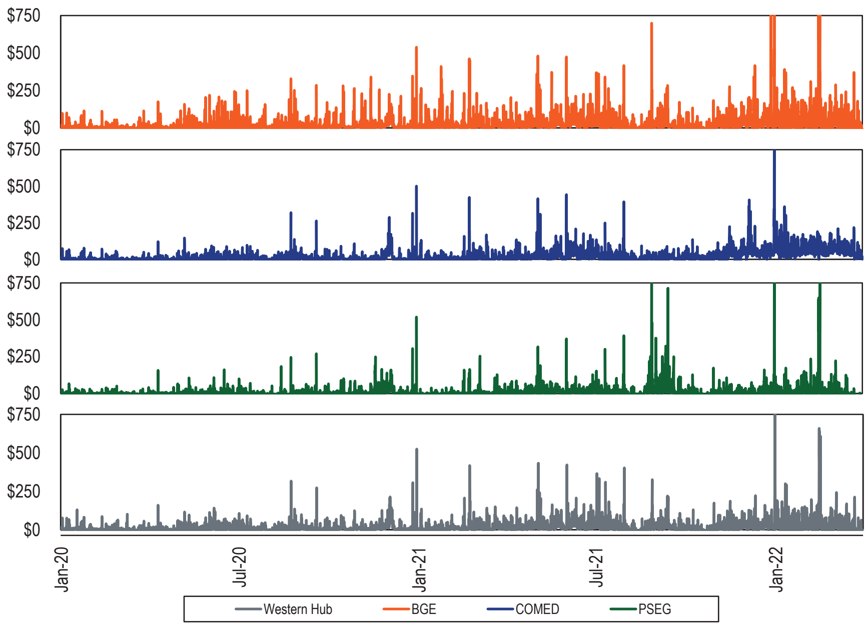
Figure 7-2 shows the hourly spark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2020 through September 2022[2]



2 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for COMED, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2020 through September 2022[3]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new unit's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new unit includes eight power plant configurations:

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant includes two GE Frame 7HA.02 CT and a single steam turbine generator with an installed capacity of 1,137.2 MW, equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT, with steam reheat, and SCR for NO_x reduction.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 104 Siemens 2.9 MW wind turbines located in COMED with an installed capacity of 301.6 MW.
- The offshore wind installation includes of 43 Siemens 7.0 MW wind turbines with an installed capacity of 301.0 MW.
- The solar installation is a 236 acre ground mounted fixed tilt solar farm located in DOM with an installed AC capacity of 100 MW.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4] [5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

3 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, daily coal prices, and average transportation costs by coal type; Powder River Basin coal for COMED, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

4 Hourly ambient conditions supplied by DTN.

5 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[6] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day annual planned outage in the fall season.

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[11] Net revenues are calculated for all zones except OVEC.[12]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[13] [14] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

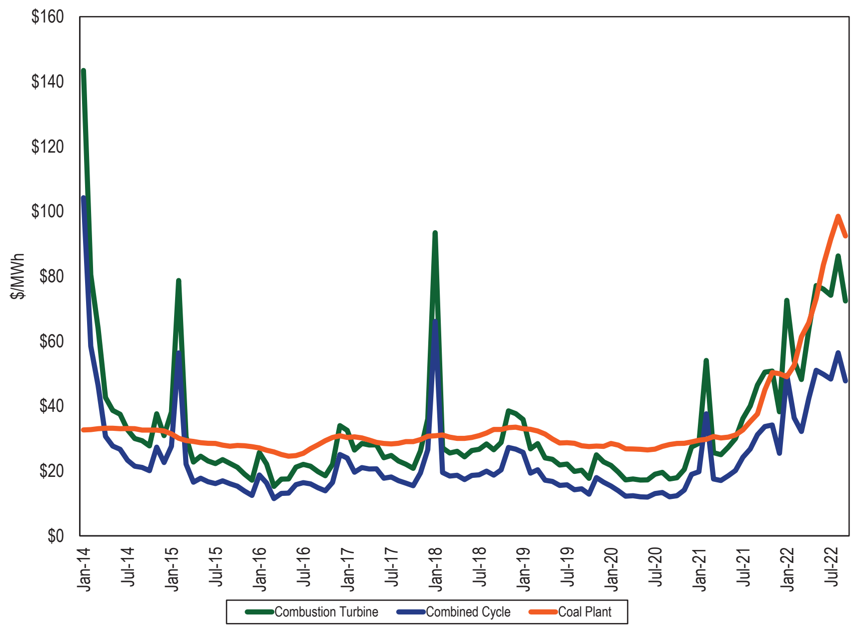
Table 7-3 Average short run marginal costs: January through September, 2022

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$69.37	9,241	$0.36
CC	$45.97	6,296	$1.41
CP	$74.18	9,250	$4.21
DS	$481.51	9,660	$0.25
Nuclear	$0.00	NA	$0.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-4). In the first nine months of 2022, both gas prices and coal prices increased. The marginal costs of a new CC were greater than the marginal cost 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. The marginal costs are based on spot fuel costs. Individual generation plants may have contracts for coal that differ significantly from spot prices.

6 CO_2 emission allowance costs only included for states participating in RGGI, including New Jersey.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt month prices obtained from Platts.
12 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
13 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

Figure 7-4 Average short run marginal costs: 2014 through September 2022



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new unit capacity factors. Table 7-4 shows the average capacity factor for new units. The capacity factors for a new CP declined in the first nine months of 2022 compared to the first nine months of 2021, while the capacity factor for a new CT increased and the capacity factors for other unit types were stable.

Table 7-4 Average capacity factor: January through September, 2014 through 2022

	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	48%	75%	62%	2%	91%	23%	17%
2015	63%	76%	57%	2%	92%	22%	19%
2016	71%	78%	48%	1%	91%	22%	17%
2017	53%	72%	40%	0%	93%	25%	19%
2018	58%	81%	42%	2%	94%	25%	18%
2019	51%	79%	24%	0%	92%	25%	19%
2020	50%	79%	11%	0%	93%	24%	18%
2021	40%	39%	39%	1%	93%	23%	18%
2022	44%	39%	31%	0%	93%	24%	19%

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least two hours, or any additional profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher in all zones in the first nine months of 2022 as a result of significantly higher and more variable energy prices, despite higher gas costs (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through September, 2014 through 2022 (Dollars per installed MW-year)[15]

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$73,405	$41,708	$46,249	$22,093	$26,654	$20,547	$5,743	$10,290	$34,702	237%
AEP	$67,449	$54,923	$47,821	$26,232	$66,440	$32,619	$28,343	$34,229	$95,083	178%
APS	$90,853	$86,337	$51,965	$31,277	$67,802	$17,863	$14,195	$23,621	$62,169	163%
ATSI	$49,411	$47,866	$46,175	$27,588	$78,519	$33,933	$28,701	$33,750	$89,066	164%
BGE	$88,636	$60,519	$79,045	$32,085	$47,455	$25,748	$22,946	$34,435	$101,176	194%
COMED	$31,315	$25,079	$29,620	$17,939	$29,727	$18,371	$15,930	$22,137	$63,554	187%
DAY	$44,343	$44,007	$44,581	$26,759	$74,664	$37,463	$32,823	$45,405	$104,484	130%
DOM	$59,305	$51,218	$55,122	$27,695	$51,983	$27,191	$23,669	$39,286	$107,215	173%
DPL	$58,747	$27,998	$24,357	$10,733	$21,770	$13,405	$8,166	$22,060	$49,218	123%
DUKE	$40,531	$41,305	$42,521	$25,534	$82,843	$33,962	$29,196	$42,284	$98,931	134%
DUQ	$39,013	$62,838	$61,651	$34,218	$50,815	$22,957	$24,168	$28,662	$69,534	143%
EKPC	$59,896	$43,174	$41,526	$21,852	$50,179	$26,697	$24,964	$31,657	$85,494	170%
JCPLC	$74,696	$40,861	$41,674	$25,592	$27,533	$19,586	$6,288	$9,372	$33,396	256%
MEC	$72,367	$72,623	$61,579	$42,471	$38,978	$23,145	$25,643	$36,920	$104,051	182%
PE	$121,487	$120,357	$76,585	$41,150	$75,603	$29,818	$31,263	$39,860	$98,179	146%
PECO	$74,378	$71,310	$58,363	$33,913	$35,130	$18,652	$18,545	$19,682	$53,776	173%
PEPCO	$64,618	$39,478	$40,681	$20,329	$38,778	$15,797	$11,062	$22,063	$56,376	156%
PPL	$190,484	$139,459	$62,799	$38,323	$77,618	$21,159	$19,976	$35,373	$93,061	163%
PSEG	$90,869	$83,039	$62,484	$39,212	$39,815	$20,785	$6,299	$13,134	$37,108	183%
REC	$66,401	$46,358	$45,660	$26,864	$29,648	$20,669	$7,102	$21,483	$41,172	92%
PJM	$58,381	$60,023	$51,023	$28,593	$50,598	$24,018	$19,251	$28,285	$73,887	161%

15 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[16] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any additional profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in all zones in the first nine months of 2022 as a result of significantly higher energy prices, despite higher gas costs (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through September, 2014 through 2022 (Dollars per installed MW-year)[17]

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$107,700	$62,168	$56,886	$39,174	$50,966	$41,724	$22,926	$9,508	$29,773	213%
AEP	$92,815	$77,655	$62,247	$44,434	$92,617	$56,774	$44,425	$31,929	$81,302	155%
APS	$131,582	$118,635	$80,327	$54,564	$102,536	$48,260	$39,833	$23,443	$63,096	169%
ATSI	$69,129	$71,026	$61,144	$45,061	$102,961	$57,830	$44,671	$32,241	$78,085	142%
BGE	$133,129	$95,354	$106,523	$57,009	$83,020	$58,009	$50,680	$30,205	$80,455	166%
COMED	$40,701	$41,928	$43,638	$30,194	$47,185	$35,931	$28,771	$21,844	$56,434	158%
DAY	$62,981	$68,115	$60,283	$45,341	$100,422	$61,853	$49,281	$38,656	$86,654	124%
DOM	$89,684	$76,237	$71,013	$46,788	$76,716	$51,745	$40,594	$34,282	$85,342	149%
DPL	$89,342	$43,314	$38,818	$18,293	$35,953	$19,416	$11,694	$12,093	$31,040	157%
DUKE	$55,669	$63,890	$57,594	$42,793	$106,861	$57,909	$45,372	$36,154	$83,249	130%
DUQ	$62,643	$74,406	$71,816	$49,873	$77,284	$44,548	$40,878	$28,550	$65,006	128%
EKPC	$81,876	$66,320	$55,747	$39,454	$76,898	$50,190	$41,067	$30,337	$75,316	148%
JCPLC	$110,941	$61,681	$52,688	$42,416	$51,793	$41,341	$23,460	$9,698	$33,050	241%
MEC	$103,350	$87,534	$68,353	$55,898	$64,015	$45,180	$40,376	$33,029	$80,980	145%
PE	$151,728	$125,644	$81,939	$55,665	$99,692	$53,422	$45,753	$35,951	$82,236	129%
PECO	$107,953	$88,284	$65,466	$48,832	$62,412	$39,572	$33,222	$24,009	$50,622	111%
PEPCO	$100,641	$73,941	$70,434	$42,566	$71,155	$44,697	$32,087	$18,877	$52,963	181%
PPL	$204,901	$137,227	$69,121	$52,350	$96,714	$41,840	$34,576	$32,114	$78,679	145%
PSEG	$131,707	$100,778	$69,820	$53,889	$67,714	$43,435	$24,685	$11,691	$34,014	191%
REC	$103,106	$65,662	$56,066	$43,741	$53,424	$43,108	$25,788	$15,522	$38,654	149%
PJM	$100,026	$79,990	$64,996	$45,417	$76,017	$46,839	$36,007	$25,507	$63,348	148%

16 All starts associated with combined cycle units are assumed to be warm starts.
17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least eight hours, or any additional profitable hours bordering the profitable day-ahead or real-time block.

New entrant CP plant energy market net revenues were higher in all but five zones in the first nine months of 2022, as a result of different relative increases in energy prices and the cost of coal by zone (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through September, 2014 through 2022 (Dollars per installed MW-year)[18]

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$113,398	$47,038	$10,176	$3,349	$29,606	$3,777	$179	$5,784	$9,855	70%
AEP	$101,550	$45,454	$30,945	$26,763	$52,538	$12,589	$4,193	$40,314	$28,854	(28%)
APS	$100,484	$40,907	$12,174	$12,354	$39,299	$4,619	$1,988	$14,164	$14,318	1%
ATSI	$112,630	$47,552	$27,158	$27,067	$54,195	$10,452	$2,774	$33,583	$35,170	5%
BGE	$160,039	$77,059	$42,361	$12,521	$47,695	$7,999	$4,767	$23,102	$42,816	85%
COMED	$100,594	$35,752	$21,437	$21,515	$26,276	$11,102	$1,478	$39,918	$134,496	237%
DAY	$104,869	$45,060	$25,861	$25,582	$52,374	$12,280	$5,245	$45,574	$28,233	(38%)
DOM	$143,983	$81,887	$39,456	$18,363	$57,001	$12,827	$5,546	$42,998	$96,459	124%
DPL	$153,229	$67,849	$20,071	$8,560	$43,597	$9,115	$4,101	$18,483	$32,138	74%
DUKE	$95,430	$41,037	$23,659	$23,198	$58,239	$10,811	$4,340	$41,361	$25,159	(39%)
DUQ	$87,779	$36,914	$23,742	$24,388	$54,041	$9,411	$3,853	$31,965	$30,983	(3%)
EKPC	$92,397	$34,882	$19,929	$18,799	$35,031	$7,634	$3,462	$35,529	$23,121	(35%)
JCPLC	$117,588	$46,725	$7,563	$4,344	$30,331	$3,387	$765	$5,606	$10,586	89%
MEC	$144,624	$64,202	$17,424	$14,224	$43,173	$7,414	$4,754	$30,300	$61,674	104%
PE	$119,745	$57,342	$21,026	$10,659	$38,207	$7,005	$3,019	$27,466	$39,260	43%
PECO	$109,397	$44,739	$8,406	$3,368	$29,236	$3,625	$254	$12,268	$17,906	46%
PEPCO	$112,907	$39,127	$9,917	$2,959	$29,507	$3,734	$508	$14,243	$16,172	14%
PPL	$108,732	$43,645	$6,736	$3,547	$28,721	$2,338	$359	$15,285	$22,151	45%
PSEG	$163,677	$72,273	$12,359	$7,058	$35,677	$5,064	$257	$5,807	$19,565	237%
REC	$158,832	$72,439	$11,758	$6,912	$34,884	$5,981	$680	$11,050	$22,283	102%
PJM	$120,094	$52,094	$19,608	$13,776	$40,981	$7,558	$2,626	$24,740	$35,560	44%

18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.[19]

New entrant nuclear plant energy market net revenues were higher in all zones in the first nine months of 2022 as a result of significantly higher energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through September, 2014 through 2022 (Dollars per installed MW-year)[20]

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$360,915	$229,102	$152,141	$165,191	$213,169	$148,853	$107,061	$180,256	$393,000	118%
AEP	$286,963	$204,221	$167,316	$178,362	$218,529	$163,269	$124,405	$206,222	$437,392	112%
APS	$311,630	$225,877	$172,174	$179,527	$230,145	$163,243	$124,485	$204,549	$443,426	117%
ATSI	$299,869	$208,113	$169,248	$181,909	$229,744	$165,213	$124,987	$203,527	$432,591	113%
BGE	$400,502	$278,999	$222,930	$196,171	$255,697	$178,806	$139,161	$229,760	$510,646	122%
COMED	$258,226	$175,674	$156,006	$166,122	$172,584	$147,141	$113,554	$194,154	$385,820	99%
DAY	$289,914	$204,805	$168,415	$182,281	$226,966	$169,847	$130,249	$218,439	$452,555	107%
DOM	$353,605	$251,055	$185,648	$188,523	$247,128	$170,020	$126,856	$221,515	$517,850	134%
DPL	$384,366	$248,859	$174,096	$174,105	$232,687	$158,433	$114,761	$202,715	$417,360	106%
DUKE	$278,699	$199,944	$165,436	$179,053	$234,243	$165,438	$125,799	$212,664	$444,766	109%
DUQ	$270,088	$195,317	$164,951	$178,387	$229,363	$162,886	$126,588	$200,496	$424,419	112%
EKPC	$274,997	$192,691	$160,945	$173,419	$203,840	$160,268	$123,371	$204,660	$439,299	115%
JCPLC	$364,815	$227,874	$146,982	$169,405	$213,944	$148,377	$107,801	$180,926	$400,592	121%
MEC	$349,545	$221,331	$148,453	$173,836	$213,225	$152,073	$113,794	$198,614	$459,916	132%
PE	$323,485	$220,294	$160,794	$172,815	$217,995	$157,504	$118,552	$197,242	$429,442	118%
PECO	$353,646	$223,312	$145,566	$164,881	$211,302	$145,791	$105,656	$178,095	$387,507	118%
PEPCO	$388,376	$262,198	$198,294	$191,299	$248,756	$173,483	$129,574	$220,188	$492,466	124%
PPL	$350,494	$221,731	$145,926	$167,451	$206,624	$144,711	$106,689	$185,085	$423,166	129%
PSEG	$385,152	$237,992	$150,318	$171,295	$218,177	$150,459	$108,427	$185,947	$406,951	119%
REC	$379,412	$239,194	$150,110	$172,155	$218,908	$153,663	$111,146	$198,097	$421,782	113%
PJM	$333,235	$223,429	$165,287	$176,309	$222,151	$158,974	$119,146	$201,158	$436,047	117%

19 The annual class average *equivalent availability* factor was used in the calculation of energy market net revenues.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones in the first nine months of 2022 (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through September, 2014 through 2022 (Dollars per installed MW-year)

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$32,623	$12,075	$2,405	$800	$9,969	$1,849	$448	$1,213	$9,663	696%
AEP	$14,425	$3,691	$831	$1,334	$4,113	$2,109	$641	$2,657	$4,286	61%
APS	$17,985	$7,169	$910	$1,194	$6,619	$1,864	$1,616	$2,367	$4,548	92%
ATSI	$14,091	$3,468	$1,973	$1,660	$6,951	$1,862	$2,056	$2,231	$4,273	92%
BGE	$49,568	$15,595	$7,196	$2,314	$12,647	$3,220	$3,503	$5,992	$12,330	106%
COMED	$11,311	$2,151	$638	$1,267	$702	$1,623	$336	$2,690	$2,878	7%
DAY	$14,235	$3,444	$905	$1,569	$3,809	$2,201	$546	$3,901	$4,428	14%
DOM	$42,535	$11,136	$2,193	$1,798	$14,452	$2,567	$1,115	$7,182	$11,320	58%
DPL	$37,438	$16,044	$3,417	$1,966	$13,916	$6,074	$7,559	$13,240	$13,430	1%
DUKE	$13,404	$2,885	$1,291	$2,991	$6,473	$2,092	$417	$3,572	$4,222	18%
DUQ	$12,963	$2,951	$2,279	$1,403	$7,949	$1,767	$3,428	$2,454	$4,247	73%
EKPC	$14,441	$2,730	$851	$896	$1,892	$1,964	$450	$3,366	$4,302	28%
JCPLC	$32,717	$13,021	$870	$1,103	$11,091	$1,774	$1,248	$1,098	$9,300	747%
MEC	$31,781	$12,875	$886	$2,585	$10,938	$1,458	$1,722	$3,983	$11,949	200%
PE	$15,964	$6,410	$876	$1,247	$5,438	$1,213	$905	$1,579	$4,080	158%
PECO	$32,130	$12,366	$862	$1,047	$9,804	$1,852	$513	$1,254	$9,620	667%
PEPCO	$51,173	$11,388	$2,939	$1,757	$12,291	$2,777	$1,110	$4,210	$10,795	156%
PPL	$32,719	$13,011	$773	$1,643	$8,764	$893	$400	$1,877	$7,800	316%
PSEG	$32,303	$12,629	$930	$1,103	$10,277	$2,120	$292	$1,626	$9,599	490%
REC	$29,837	$13,705	$973	$1,113	$9,530	$2,084	$595	$6,116	$9,317	52%
PJM	$29,787	$8,937	$1,700	$1,539	$8,381	$2,168	$1,445	$3,630	$7,619	110%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly assuming the unit generated at the average capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[21]

Onshore wind energy market net revenues were higher in the first nine months of 2022 as a result of significantly higher energy prices.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2022

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
AEP	$80,488	$54,850	$45,842	$48,743	$69,611	$49,912	$30,754	$47,276	$106,828	126%
APS	$83,957	$55,410	$40,843	$51,330	$69,984	$42,199	$32,374	$42,649	$96,708	127%
COMED	$72,887	$46,732	$39,315	$48,121	$46,613	$44,297	$26,061	$46,357	$97,383	110%
PE	$101,629	$67,821	$42,369	$50,687	$69,843	$41,131	$28,813	$40,510	$90,826	124%

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated at a 45 percent capacity factor.

Offshore wind energy market net revenues were higher in the first nine months of 2022 as a result of higher energy prices.

Table 7-11 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2022

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$168,494	$108,246	$72,635	$78,368	$102,218	$72,559	$52,652	$86,330	$191,831	122%
DOM	$177,744	$117,737	$88,878	$89,482	$119,114	$81,496	$61,681	$109,279	$260,450	138%
DPL	$180,106	$118,452	$80,593	$82,710	$112,964	$77,924	$58,298	$101,841	$207,983	104%

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW.[22]

Solar energy market net revenues were higher in the first nine months of 2022 as a result of significantly higher energy prices.

21 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
22 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.

Table 7-12 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through September, 2014 through 2022

	Jan-Sep									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$60,221	$43,274	$32,609	$31,056	$35,469	$27,917	$19,596	$32,504	$81,463	151%
DOM	-	-	$58,175	$57,902	$65,866	$49,013	$36,735	$68,442	$197,389	188%
DPL	-	-	$37,917	$42,030	$51,312	$39,029	$27,848	$40,417	$94,522	134%
JCPLC	$56,051	$36,464	$28,520	$30,176	$33,486	$25,962	$19,723	$31,508	$75,466	140%
PSEG	$54,074	$42,695	$32,929	$33,321	$36,560	$29,236	$21,338	$36,438	$82,821	127%

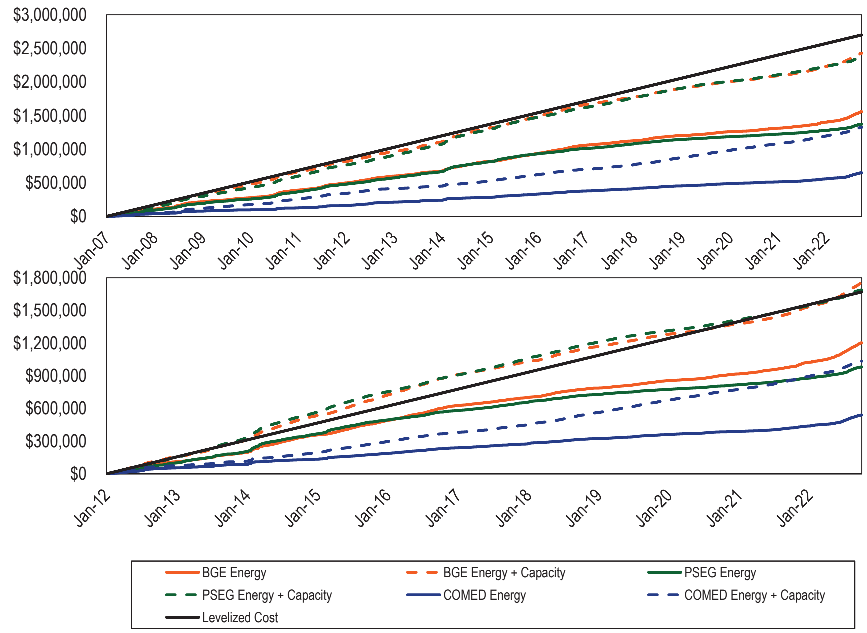
Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 90 percent of their total costs in the BGE Zone and 88 percent of total costs in the PSEG Zone, and 49 percent of total costs in the COMED Zone, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered over 100 percent of their total costs on a cumulative basis in the BGE Zone and PSEG Zone and 62 percent of total costs in the COMED Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs. Covering 100 percent of total costs in this analysis includes earning the assumed rate of return. Units earned a positive rate of return even when covering less than 100 percent of the identified costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation, ignoring the benefits of competition on reducing costs and improving technology and ignoring the possibility of over earning under cost of service regulation.

Figure 7-5 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-5 Historical new entrant CC revenue adequacy: 2007 through September 2022 and 2012 through September 2022[23]



23 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for COMED, and Texas Eastern M3 for PSEG.

Table 7-13 shows the percent of levelized total costs recovered.

Table 7-13 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	90%	105%
COMED	49%	62%
PSEG	88%	101%

The assumptions used for this analysis are shown in Table 7-14.

Table 7-14 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[24] [25] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, for 2020.[26] This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (a 12.8 percent decrease from 2012 through 2020 for all plants including single and multiple unit plants).[27] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 49.1 percent decrease from 2012 through 2020 for all plants including single and multiple unit plants).[28] NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[29] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on current year prices.[30] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. In 2020, PJM energy prices were at the lowest level since the introduction of competitive markets, even lower than in 2016. Average energy prices in the first nine months of 2022 are higher than historical

24 Operating costs from: Nuclear Energy Institute (November, 2021). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context-2021.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

25 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

26 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average costs than BWR reactors.

27 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants increased by $1.73/MWh, or 7.0 percent, from 2019 to 2020. Operating costs for multiple unit plants decreased by $0.57/MWh, or 3.4 percent, from 2019 to 2020.

28 Capital expenditures have decreased 44.1 percent since 2012 for single unit plants and 49.5 percent for multiple unit plants.

29 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.09 per MWh for a nuclear power plant operating at a capacity factor of 0.918 percent.

30 The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program.* Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring.*

energy prices for all full years since 2008. Nuclear plant energy revenues based on forward period prices are higher than all previous years. The actual results for individual nuclear plants are a function of the degree to which actual unit costs are less than or greater than the benchmark NEI data.

Table 7-15 includes the publicly available data on energy market prices, Table 7-16 and Table 7-17 show capacity market prices and Table 7-18 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[31] The analysis excludes the Cook nuclear units, the Catawba 1 nuclear unit, and the North Anna and Surry nuclear units. The Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[32] Catawba 1 is not in PJM but is pseudo tied to PJM. North Anna 1 and 2 and Surry 1 and 2 are part of the Dominion FRR for the 2022/2023 Delivery Year.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Historical nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

Table 7-15 Nuclear unit day-ahead LMP: 2008 through 2021

	ICAP	Average DA LMP ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33	$37.07
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23	$33.74
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66	$32.81
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73	$34.32
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32	$30.16
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31	$31.05
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06	$39.99
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	NA	NA	NA	NA
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49	$37.76
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95	$31.39
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41	$39.30
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	NA	NA	NA

31 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
32 See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

Table 7-16 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2023/2024[33 34]

	ICAP	BRA Capacity Price ($/MW-Day)																
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50	$34
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34
Calvert Cliffs	1,708	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49
LaSalle	2,271	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	NA	NA	NA
Peach Bottom	2,347	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34
Salem	2,328	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA
Susquehanna	2,520	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	NA	NA

Table 7-17 Nuclear unit capacity market revenue ($/MWh): 2008 through 2023[35 36]

	ICAP	Capacity Revenue ($/MWh)														
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	$3.92	$1.83
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46	$2.18
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46	$2.18
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.09	$5.29	$5.13	$3.09
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.84	$5.94	$4.51	$1.83
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46	$2.18
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67	$3.13
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46	$2.18
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67	$3.13
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	NA	NA
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67	$3.13
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.84	$5.94	$4.51	$1.83
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46	$2.18
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67	$3.13
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	NA	NA
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.08	$5.29	$5.13	$3.09
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.08	$5.29	NA	NA

33 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

34 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

35 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2021 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

36 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-18 Nuclear unit costs: 2008 through 2020[37] [38]

	ICAP	NEI Costs ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$39.64
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	NA	NA	NA	NA
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$39.64
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.03
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	NA	NA	NA

In 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-19 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM and Oyster Creek and Three Mile Island calculated using historic LMP and cost data. In 2021, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[39] Unforced capacity is determined using the annual class average EFORd rate.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[40] Quad Cities did not clear in the 2020/2021 Auction.[41] Dresden and most of Byron did not clear in the 2021/2022 Auction.[42] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[43] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[44]

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative

37 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>.

38 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

39 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

40 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

41 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

42 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.

43 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.

44 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.

energy market prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, an average of 0.1 percent and a maximum of 1.7 percent in 2020, an average of 0.0 percent and a maximum of 0.3 percent in 2021, and an average of 0.0 percent and a maximum of 0.0 percent in 2022.[45]

In 2021, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-19 Nuclear unit surplus (shortfall) based on public data: 2008 through 2021

	ICAP	Surplus (Shortfall) ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($2.6)	$15.4
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.1)	($1.5)	$6.0	$3.9	$0.1	$15.6
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.5)	($2.7)	$5.8	$3.2	($0.5)	$14.6
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.3	$6.1	$16.3	$5.4	($0.9)	$19.7
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.2)	($15.0)	$3.9
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.0)	$7.2	$4.6	$0.7	$16.3
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.0)	$1.6	$12.3	$1.7	($2.2)	$11.4
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.5)	($1.8)	$6.0	$3.8	($0.1)	$15.4
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.7	($2.5)	$12.0
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$18.2
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA	NA
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.7	($2.7)	$11.9
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.3)	$1.9	($5.8)	($15.1)	$4.3
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.4)	$4.4	$2.1	($2.3)	$13.2
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.3)	$1.3	$11.9	$1.4	($2.5)	$11.1
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.1	($2.6)	$17.6
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.4)	($6.6)	$8.9
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2022, 2023 and 2024 and known capacity market prices for 2022. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values. Nuclear plants may sell their output at a range of forward prices and for a range of future years.

Table 7-20 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2022 through 2024. Capacity revenues are not presented for calendar year 2024 because the 2024/2025 BRA has not been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[46] Forward prices are as of October 3, 2022. The 2022 energy prices in Table 7-20 include actual day-ahead market prices through September 30, 2022, and forward prices for October through December 2022. The capacity prices are known based on PJM capacity auction results.

45 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.
46 Forward prices on October 3, 2022. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2021 data.

Table 7-20 Forward prices in PJM energy markets, capacity revenue, and annual costs

	ICAP	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)		2020 NEI Costs ($/MWh)		
	(MW)	2022	2023	2024	Reactive	2022	2023	Fuel	Operating	Capital
Beaver Valley	1,808	$69.94	$70.56	$55.55	$0.25	$5.12	$3.92	$5.76	$16.43	$4.84
Braidwood	2,337	$61.42	$66.62	$52.43	$0.25	$8.66	$5.46	$5.76	$16.43	$4.84
Byron	2,300	$59.89	$63.97	$50.36	$0.21	$8.66	$5.46	$5.76	$16.43	$4.84
Calvert Cliffs	1,708	$80.80	$77.86	$61.32	$0.20	$5.29	$5.13	$5.76	$16.43	$4.84
Davis Besse	894	$70.35	$70.17	$55.21	$0.25	$5.94	$4.51	$5.76	$26.33	$7.55
Dresden	1,797	$62.61	$67.78	$53.34	$0.33	$8.66	$5.46	$5.76	$16.43	$4.84
Hope Creek	1,172	$60.58	$62.84	$49.36	$0.43	$7.87	$5.67	$5.76	$16.43	$4.84
LaSalle	2,271	$61.12	$66.27	$52.15	$0.18	$8.66	$5.46	$5.76	$16.43	$4.84
Limerick	2,242	$62.47	$63.23	$49.70	$0.14	$7.87	$5.67	$5.76	$16.43	$4.84
North Anna	1,892	$78.64	$76.45	$60.21	$0.17	$5.12	NA	$5.76	$16.43	$4.84
Peach Bottom	2,347	$62.26	$62.92	$49.43	$0.29	$7.87	$5.67	$5.76	$16.43	$4.84
Perry	1,240	$71.49	$71.90	$56.60	$0.25	$5.94	$4.51	$5.76	$26.33	$7.55
Quad Cities	1,819	$59.41	$61.25	$48.28	$0.18	$8.66	$5.46	$5.76	$16.43	$4.84
Salem	2,328	$60.54	$62.74	$49.28	$0.13	$7.87	$5.67	$5.76	$16.43	$4.84
Surry	1,676	$76.48	$75.68	$59.60	$0.17	$5.12	NA	$5.76	$16.43	$4.84
Susquehanna	2,520	$60.97	$60.50	$47.57	$0.29	$5.29	$5.13	$5.76	$16.43	$4.84

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order about inclusion of maintenance expense in energy offers, major maintenance costs can no longer be included in gross ACR values.[47] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel, operating cost, and incremental capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM, given that NEI does not provide a breakout of major maintenance. NEI incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

47 See 167 FERC ¶ 61,030 at P 41.

All generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

In Table 7-21, the capacity price required to cover avoidable costs in $ per MWh is calculated by taking the total NEI costs in $ per MWh and subtracting the total expected energy and ancillary services revenues in $ per MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average equivalent availability factor. Total expected ancillary services revenue is unit specific reactive capability revenue.[48] The capacity price required to cover avoidable costs in $ per MW-day is calculated by multiplying the required price in $ per MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-21, for 2022, using actual day-ahead market prices through September 30, 2022, and forward prices, as of October 3, 2022, for October through December 2022, the capacity price required to cover avoidable costs is $0/MW-day for all units using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance.[49] Net revenues based on forward energy prices are greater than or equal to avoidable costs in 2022, 2023, and 2024 without any contribution from capacity market revenues. The result is that all net ACR values in Table 7-21 are zero.

48 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.

49 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-21 Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2022	2023	2024	2022	2023	2024	2022	2023	2024
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,708	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,271	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,347	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,328	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,520	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 7-22 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2020 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-22 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that all nuclear plants are expected to cover their annual avoidable costs in 2022, 2023, and 2024.

Hope Creek, Quad Cities, and Salem all currently receive subsidies. Braidwood, Byron, Dresden, and LaSalle will receive a subsidy if necessary to meet a target net revenue value, in dollar per MWh, from the energy and capacity markets. Based on forward prices as of October 3, 2022, and NEI average costs, none of these units need a subsidy, and therefore zero subsidy values are included for these plants in Table 7-22.

Table 7-22 Nuclear unit forward annual surplus (shortfall)[50 51 52 53 54]

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2022	Surplus (Shortfall) ($/MWh) 2023	Subsidy ($/MWh) 2022	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2022	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2023	Surplus (Shortfall) Including Subsidy ($ in millions) 2022	Surplus (Shortfall) Including Subsidy ($ in millions) 2023
Beaver Valley	1,808	$48.27	$47.70		$704.7	$693.5	$704.7	$693.5
Braidwood	2,337	$43.29	$45.30	$0.00	$816.8	$851.3	$816.8	$851.3
Byron	2,300	$41.74	$42.61	$0.00	$775.0	$788.1	$775.0	$788.1
Calvert Cliffs	1,708	$59.27	$56.16		$817.1	$771.4	$817.1	$771.4
Davis Besse	894	$36.90	$35.28		$266.7	$253.7	$266.7	$253.7
Dresden	1,797	$44.57	$46.53	$0.00	$646.5	$672.4	$646.5	$672.4
Hope Creek	1,172	$41.85	$41.91	$10.00	$396.0	$395.0	$490.3	$489.2
LaSalle	2,271	$42.93	$44.88	$0.00	$787.1	$819.7	$787.1	$819.7
Limerick	2,242	$43.45	$42.01		$786.4	$757.4	$786.4	$757.4
North Anna	1,892	$56.90	NA		$869.0	NA	$869.0	NA
Peach Bottom	2,347	$43.39	$41.85		$822.1	$789.8	$822.1	$789.8
Perry	1,240	$38.04	$37.01		$381.3	$369.1	$381.3	$369.1
Quad Cities	1,819	$41.22	$39.86	$16.50	$605.3	$583.0	$846.7	$824.4
Salem	2,328	$41.51	$41.50	$10.00	$780.2	$776.9	$967.4	$964.1
Surry	1,676	$54.74	NA		$740.6	NA	$740.6	NA
Susquehanna	2,520	$39.52	$38.89		$804.2	$788.2	$804.2	$788.2

50 Report to the General Assembly in Compliance with Section 1-75(d-5) of the Illinois Power Agency Act 20 ILCS 3855/1-75(d-5)(F)(2). Illinois Commerce Commission. August 2019. The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.

51 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek, Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080557 (April 27, 201). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs*. BPU Docket No. ER20080557 (April 27, 2021).

52 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

53 The subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.

54 The Illinois Energy Transition Act, SB 2408.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The investments required for environmental compliance have affected offer behavior in the capacity market. Expectations about the cost and life of such investments and about future capacity and energy prices have affected retirement decisions. The markets have also provided incentives for new, lower emission units to enter.

Overview

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[2] The list of coal steam units subject to MATS, however, remains in place.[3] 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.[4] 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.[5] 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.[6] The proposed FIP requirements would establish ozone season NO_X 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.[7] 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.[8] 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

1 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

2 *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.

3 *Id.* at 31291.

4 CAA § 110(a)(2)(D)(i)(I).

5 *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).

6 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).

7 *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).

8 See 40 CFR § 63.6640(f).

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.[9] 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.[10]
- **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.[11] 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.

9 *West Virginia v. EPA*, No. 20-1530 (S. Ct. of the U.S.).
10 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).
11 42 U.S.C. §§ 6901 *et seq.*

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 to power generation facilities. New Jersey rejoined on January 1, 2020.[12] 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.[13] [14] [15] 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.

12 "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>.
13 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.
14 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/> .
15 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).

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.[16]

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.

16 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.

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.

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.)

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.[17] 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.[18] 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 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.[19] 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

17 "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>.

18 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.

19 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.

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.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[20]

The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[21] [22]

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[23] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

20 For more details, see the *2019 State of the Market Report for PJM*, Vol. II, Appendix H: "Environmental and Renewable Energy Regulations."

21 42 U.S.C. § 7401 et seq. (2000).

22 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

23 42 U.S.C. §§ 6901 *et seq.*

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.

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.[24] 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. This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112.[25] The immediate practical effect is limited because the emission standards and other requirements of the 2012 MATS rule remain in place and the list of coal and oil fired power plants regulated under Section 112 of the Act remains in place.[26] Restoration of the appropriate and necessary finding removes the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On January 20, 2021, an executive order was issued stating national objectives "to listen to the science; to improve public health and protect our environment; to ensure access to clean air and water; to limit exposure to dangerous chemicals and pesticides; to hold polluters accountable, including those who disproportionately harm communities of color and low-income communities; to reduce greenhouse gas emissions; to bolster resilience to the impacts of climate change; to restore and expand our national treasures and

24 See *Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Notice of Proposed Rulemaking, EPA-HQ-OAR-2018-0794, 87 Fed. Reg. 7624 (February 9, 2022).

25 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.

26 *Id.* at 31291. The EPA explains (*id.*): "The Court's holding in *New Jersey* [517 F.3d 574 (D.C. Cir. 2008)] plainly states that CAA section 112(c)(9) 'unambiguously limit[s] EPA's discretion to remove sources, including EGUs, from the section 112(c)(1) list once they have been added to it.' 517 F.3d 574, 583 (D.C. Cir. 2008)."

monuments; and to prioritize both environmental justice and the creation of the well-paying union jobs necessary to deliver on these goals" ("Executive Order 13990").[27] The order directs government agencies to immediately review, and as appropriate and consistent with applicable law, "take action to address the promulgation of Federal regulations and other actions during the last 4 years that conflict with these important national objectives, and to immediately commence work to confront the climate crisis."[28] The May 22, 2021, supplemental finding on MATS is an action specified for review.[29]

On April 9, 2020, the EPA finalized a rule establishing a new sub category in the MATS with less stringent requirements for units fueled by eastern bituminous refuse coal, waste coal.[30] The rule allows four refuse coal plants, Grant Town Power Plant (Unit 1A and 1 B (40 MW each)) in West Virginia; and Colver Power Project (110 MW), Ebensburg Power Plant (50 MW), and Scrubgrass Generating Co. (Units 1 and 2 (42 MW each)) in Pennsylvania; to emit higher levels of acid gases and SO_2.[31] The EPA stated that it was concerned that units would close and leave coal refuse piles, which are prone to smoldering and emit uncontrolled acid gases and other HAP.[32]

CAA: NAAQS/CSAPR

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[33]

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[34] the EPA finalized increases to the good neighbor obligations (i.e. reduced allowable emissions) under the 2008 ozone NAAQS for 12 states.[35] Eleven of the affected states are PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The EPA determined that Tennessee's emissions budget "fully eliminated the state's significant contribution to downwind nonattainment and interference with maintenance of the 2008 ozone NAAQS."[36] For the remaining PJM states, projected 2021 emissions were found to contribute at or above a threshold of 1 percent of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.[37] Starting with the 2021 ozone season for emissions trading under CSAPR, the new FIPs require power plants in the affected states (also including Louisiana and New York) to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program.[38] Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NO_x Ozone Season Group 2 Trading Program.[39] [40]

27 *See* President Joseph R. Biden Jr., Executive Order 13990 re "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" ("Executive Order 13990").
28 *Id.* (Sec. 1).
29 *Id.* at Sec. 2(iv).
30 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Subcategory of Certain Existing Electric Utility Steam Generating Units Firing Eastern Bituminous Coal Refuse for Emissions of Acid Gas Hazardous Air Pollutants*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 20838 (April 15, 2020).
31 *Id.* at 20841.
32 *Id.* at 20847.

33 Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland. See *Response to Clean Air Act Section 126(b) Petitions From Delaware and Maryland*, EPA Docket No. EPA-HQ-OAR-2018-0295, 83 Fed. Reg. 50444 (Oct. 5, 2018). Delaware filed a petition requesting that the EPA regulate emissions from the Brunner Island coal plant in Pennsylvania, the Harrison coal plant in West Virginia, the Homer City coal plant in Pennsylvania and the Conemaugh coal plant in Pennsylvania. Maryland filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. U.S. Court of Appeals for the D.C. Circuit Case No. 18-1285. On May 15, 2020, the Court denied an appeal of the EPA decision filed by Maryland, except that the Court agreed that EPA did not sufficiently support its rejection based on the cost effectiveness of Maryland's request that two waste coal plants, Cambria Cogeneration (Pa.) and Grant Town Cogen (W.Va.), be required to operate selective noncatalytic reduction (SNCR) controls, and remanded the decision. Maryland v. Wheeler, Case No. 18-1285 (D.C. Cir May 19, 2020).
34 Wisconsin v. EPA, 938 F.3d 303, 318–20 (D.C. Cir. 2019).
35 *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).
36 *Id.* at 23066.
37 *Id.* at 23085–23086.
38 *Id.* at 23121.
39 *Id.*
40 On April 30, 2021, the MMU sent a market message to PJM market participants explaining how to account for the changes in cost-based offers. *See* "CSAPR Ozone Season Changes," <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CSAPR_Ozone_Season_Changes_20210430.pdf>

On February 28, 2022, 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.[41] The proposal would fully resolve the CAA good neighbor obligations of the 26 states for the 2015 Ozone NAAQS. The proposed FIP requirements would establish ozone season NO_x emissions budgets for electric generating units in the following PJM states: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. The list of PJM jurisdictions excludes North Carolina and the District of Columbia, but includes Delaware. Electric generating units in the indicated states would be required to participate in a revised version of the CSAPR NO_x Ozone Season Group 3 Trading Program that was previously established in the 2021 CSAPR Update.

The EPA's new emissions budgets for each PJM state for each ozone season for 2021 through 2024, and beyond are shown in Table 8-1. Table 8-1 also includes the states budgets that would have been in effect had the rules not been revised.

Table 8-1 CSAPR NO_x ozone season group 3 state budgets: 2021 through 2024[42 43]

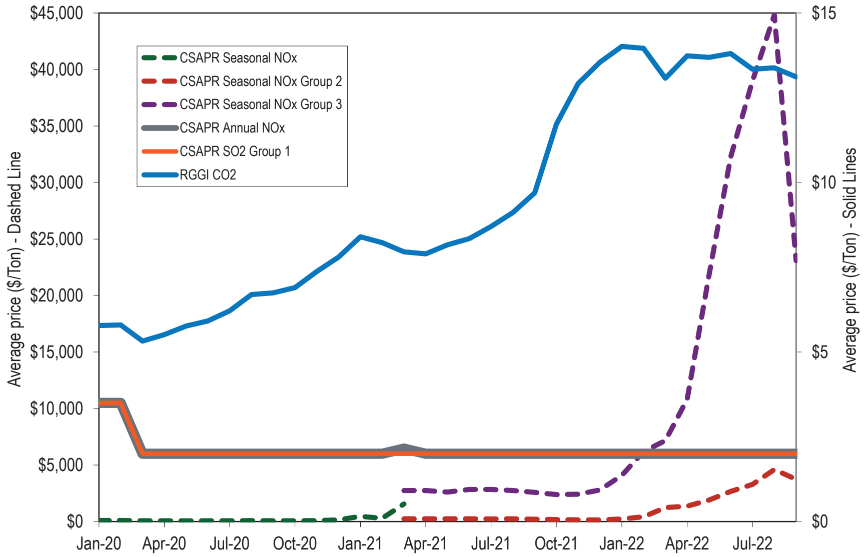
	Emissions Budget (Tons)							
	Budget without revised rule				Revised Budget			
PJM State	2021	2022	2023	2024+	2021	2022	2023	2024+
Illinois	9,368	9,368	8,413	8,292	9,102	9,102	8,179	8,059
Indiana	15,856	15,383	15,357	12,232	13,051	12,582	12,553	9,564
Kentucky	15,588	15,588	15,588	15,588	15,300	14,051	14,051	14,051
Maryland	1,501	1,267	1,267	1,350	1,499	1,266	1,266	1,348
Michigan	13,898	13,459	11,182	10,968	12,727	12,290	9,975	9,786
New Jersey	1,346	1,346	1,346	1,346	1,253	1,253	1,253	1,253
Ohio	15,829	15,927	15,927	15,927	9,690	9,773	9,773	9,773
Pennsylvania	11,896	11,896	11,896	11,896	8,379	8,373	8,373	8,373
Virginia	4,664	4,274	4,361	4,025	4,516	3,897	3,980	3,663
West Virginia	15,165	15,165	15,165	15,165	13,334	12,884	12,884	12,884

Figure 8-1 shows average, monthly settled prices for NO_x and SO_2 emissions allowances including CSAPR related allowances for January 2020 through September 2022. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first nine months of 2022, CSAPR annual NO_x prices were 0.8 percent lower on average than in the first nine months of 2021. The group 2 CSAPR Seasonal NO_x price averaged $2,159.34 in the first nine months of 2022, a 820.9 percent increase over the group 2 CSAPR Seasonal NO_x price for the first nine months 2021.[44] The group 3 CSAPR Seasonal NO_x price averaged $21,023.58 in the first nine months of 2022, a 669.5 percent increase over the group 3 CSAPR Seasonal NO_x price for the first nine months of 2021.[45] The components of LMP analysis shows that NO_x cost contributed $3.03 to the load-weighted average LMP in the first nine months of 2022, compared to $0.16 in the first nine months of 2021.[46]

41 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).
42 *Id.* at 23123-23124 (Table VII.C.2-1-4).
43 *See* "State Budgets under the Revised Cross-State Air Pollution Rule Update," EPA, <https://www.epa.gov/csapr/state-budgets-under-revised-cross-state-air-pollution-rule-update>.
44 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.
45 Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia participate in the CSAPR NO_x Ozone Season Group 3 Trading Program.
46 See Components of LMP in 2022 Quarterly State of the Market Report for PJM: January through September, Section 3: Energy Market (November 10, 2022).

Figure 8-1 Spot monthly average emission price comparison: January 2020 through September 2022



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[47] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[48]

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units. The first part considers whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second part considers whether any identified increase is also a "significant net emission increase."

On August 1, 2019, the EPA proposed revisions to the NSR permitting program under which, both emissions increases and decreases from a major modification would be considered in the first part of the NSR applicability test.[49] Under the revised rule the need for a permit and associated investments in pollution controls would be more frequently avoided than under the current rule.

On March 25, 2020, the EPA released a memorandum changing the EPA's longstanding interpretation of "begin actual construction" under the NSR preconstruction permitting regulations.[50] [51] EPA policy has been to preclude almost every physical onsite construction activity that is of a permanent nature prior to issuance of a permit. Under the new interpretation, which focuses on the statutory meaning of "emissions unit,"[52] the policy precludes only the construction of the emissions unit. The EPA clarified that the costs and consequences of pre permit construction are risks born by the owner/operators if no permit issues, or issues without the expected terms or conditions. The new interpretation significantly expands the scope of activity that an owner/operator willing to assume the risks may undertake prior to receiving an NSR permit when constructing a project that will include an emissions unit.

On April 21, 2022, EPA issued for public input a draft technical non regulatory white paper on control techniques and measures that could reduce GHG emissions from new stationary CTs.[53]

CAA: RICE

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power,

47 42 U.S.C § 7470 et seq.

48 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

49 *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).

50 See Anne L. Idsal, Principal Deputy Assistant Administrator, Memorandum re Interpretation of "Begin Actual Construction" Under the New Source Review Preconstruction Permitting Regulations" ("March 25th Memo").

51 See 40 CFR § 52.21(b)(11); 40 CFR § 52.21(a)(2)(iii).

52 40 CFR § 52.21(b)(7) ("any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit…").

53 The draft white paper can be accessed here: <https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf>.

including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet EPA emissions standards (emergency stationary RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[54] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet 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 does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate. 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.

54 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[55] [56]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[57] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer reviewed.[58] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on Social Cost of Carbon analyses.

Executive Order 13990, Section 6, establishes an Interagency Working Group on the Social Cost of Greenhouse Gases. The group is tasked to develop estimates in the form of monetized damages for the "social cost of carbon" (SCC), the "social cost of nitrous oxide" (SCN), and the "social cost of methane" (SCM), associated with incremental increases in greenhouse gas emissions. The cost estimates would be used by EPA and other agencies to determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses of regulatory and other actions.

Effective October 23, 2015, the EPA placed national limits on the amount of CO_2 that new, modified or reconstructed fossil fuel fired steam power plants would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG NSR Rule).[59] On December 12,

55 See CAA § 111.

56 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

57 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).

58 *Id.*

59 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) ("2015 GHG NSR Rule"); 40 CFR Part 60, subpart TTTT.

2018, the EPA proposed to revise the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.[60]

On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan, which ACE had replaced. On February 12, 2021, the EPA issued a memo stating that as a result of the court vacating ACE without reinstating the Clean Power Plan ("CPP"), there are no effective regulations under CAA section 111(d) with respect to greenhouse gas emissions from electric generating units at this time, and states are not currently required to submit plans.[61] The memo also noted: "ongoing changes in electricity generation mean that the emission reduction goals that the CPP set for 2030 have already been achieved."[62]

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.[63] 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.

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[64] [65] The definition of WOTUS is a threshold issue that determines the hydrological scope of the CWA's applicability. Over the past decade, attempts to define WOTUS have been repeatedly addressed by the Courts, and no durable definition has resulted.[66] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

October 22, 2019, a new rule that would have defined WOTUS more narrowly was vacated by the U.S. District Court District of Arizona.[67] [68] The new rule was never implemented.

Based on the Court action, the EPA now interprets WOTUS consistent with the pre 2015 regulatory regime. 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," updated to reflect consideration of Supreme Court decisions.[69]

The scope of the CWA has expanded as a result of a decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[70] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[71] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[72] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[73] Additional litigation or administrative action may clarify the functional discharge analysis.[74] *County of Maui* reduces the

60 *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495; FRL-9987-85- OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) ("2018 Proposed Rev. GHG NSR").

61 *See* Joseph Goffman, Acting Assistant Administrator, EPA, Memo re Status of Affordable Clean Energy Rule and Clean Power Plan (February 12, 2021).

62 *Id.*, citing "Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," EPA-452/R-19-003 (June 2019), at 2-14 to 2-15.

63 *West Virginia v. EPA*, No. 20-1530 (S. Ct. of the U.S.).

64 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

65 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."

66 See, e.g., Rapanos v. U.S., 547 U.S. 715 (2006); Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001); U.S. v. Riverside Bayview Homes, Inc., 474 U.S. 121 (1985).

67 See *The Navigable Waters Protection Rule: Definition of "Waters of the United States,"* EPA Docket No. EPA-HQ-OW-2018-0149, 85 Fed. Reg. 22250 (April 21, 2020).

68 See Pascua Yaqui Tribe v. U.S. EPA, No. CV-20-00266-TUC-RM, __ F.Supp.3d __ (USDC Ariz. 2021).

69 *See Revised Definition of "Waters of the United States,"* Docket No. EPA-HQ-OW-2021-0602; FRL-6027.4-03- OW, 86 Fed. Reg. 69372 (December 7, 2021); Pasqua Yaqui Tribe v. EPA, Case No. CV-20-00266-TUC-RM, ___ F.Supp.3d ___ (USDC D. Ariz. 2021).

70 Slip. Op. No. 18-260 (April 23, 2020).

71 *Id.*

72 *Id.* at 1.

73 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").

74 *Id.*

importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[75]

Effluents

The EPA regulates under its National Pollutant Discharge Elimination System (NPDES) permitting authority discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[76]

Executive Order 13990 called for review and improvement of the existing 2020 Steam Electric Reconsideration Rule. The EPA intends to issue a proposed rule in the fall of 2022 to strengthen certain discharge limits applicable to steam generating units. [77]

On June 9, 2022, the EPA proposed the Water Quality Certification Improvement Rule (WQCIR), which would expand the grounds on which states may condition or block, projects in federal permit proceedings.[78] The WQCIR would provide each state certifying agency a role in determining the "reasonable period of time" to review the request and encourage their adoption of an "activity as a whole" analytical approach that would consider the impacts of the entire project rather than just the specific discharge needing certification.[79]

The EPA is currently implementing its 2015 and 2020 rules.[80] [81] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[82] Some owners have already indicated an intent to close generating units based on the discharge limits in the 2020 Rule.

The EPA is now implementing its Effluent Guidelines. The EPA has also proposed to tighten those guidelines.[83] The Effluent Guidelines establish effluent limitations and pretreatment standards applicable to steam electric generating units. Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or retiring their units by 2028.[84]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[85] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

In April 2015, the EPA issued a rule under RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[86] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet

75 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").
76 See 40 CFR Part 423. For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."
77 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021).
78 See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).
79 *Id.* at 35343–35349.
80 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015).
81 See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).
82 *Id.* at 64652.
83 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021); *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020); *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015) (collectively "Effluent Guidelines").
84 85 Fed. Reg. 64650, 64679-82.
85 42 U.S.C. §§ 6901 *et seq.*
86 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[87]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[88]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has an EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

87 The Water Infrastructure Improvements for the Nation Act (WIIN Act).
88 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[89] On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders ("Revised CCRR").[90] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[91] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be "technically feasibly implemented."[92] Utilities had until November 30, 2020, to obtain an automatic extension upon certification of need for additional time.[93] [94] Upon receipt of required documentation satisfying certain criteria, the EPA could grant certain extensions, including to as late as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[95]

The EPA has under review 16 completed applications from PJM plants for extensions of the deadline for compliance with the Revised CCRR. The EPA has proposed action on three applications.

The EPA has proposed to deny two applications affecting PJM power stations: The General James M. Gavin Plant (2,600 MW) owned by Lightstone Generation LLC, a 50-50 joint venture of funds managed by ArcLight Capital Partners and Blackstone Group, Inc., and is located in Cheshire, Ohio (Gavin);[96] and the Clifty Creek Power Plant (1,300 MW) owned by Ohio Valley Electric Corp. (OVEC) and located in Madison, Indiana (Clifty Creek).[97] The comment period for the proposed denial for both plants ends February 23, 2022. The EPA proposes that both Gavin and Clifty Creek cease receipt of waste and initiate

89 Utility Solid Waste Activities Group, et al. v. EPA, No. 15-1219 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).
90 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002- 02-OLEM, 85 Fed. Reg. 53516 (August 28, 2020).
91 *Id.* at 53516-53517, 53536.
92 *Id.* at 53546; 40 CFR § 257.103(f)(1).
93 *Id.* at 65942.
94 A number of plants in PJM timely filed for extensions.
95 *Id.*
96 Proposed Denial of Alternative Closure Deadline for General James M. Gavin Plant, Proposed Decision, Docket No.: EPA-HQ-OLEM-2021-0590 (January 11, 2022) ("Gavin Proposed Denial Order").
97 Proposed Denial of Alternative Closure Deadline for Clifty Creek Power Station, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0587(January 11, 2022) ("Clifty Creek Proposed Denial Order").

closure of its surface impoundment no later than 135 days from the date of the EPA's final decision.[98] The EPA provides the potential for an extension for such period that PJM may determine that Gavin or Clifty Creek is needed for reliability and the EPA agrees is appropriate.[99]

The EPA proposed to approve East Kentucky Power Cooperative's request to extend its deadline to discontinue use of an unlined ash pond to November 30, 2022, for its H.L. Spurlock Plant (1,350 MW) in Maysville, Kentucky.[100] The proposed extension is on condition that groundwater monitoring issues are addressed.[101]

The EPA proposed on July 12, 2022, to approve Appalachian Power Company's (AEP) request to extend its deadline to discontinue use of an unlined ash pond to January 9, 2023, for its Mountaineer Power Plant (1,300 MW) in Letart, West Virginia.[102] The proposed extension is on condition that groundwater monitoring issues are addressed.[103]

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in non participating states, noticed February 20, 2020.[104] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of its own CCR permit program.

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions. On July 1, 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[105] Dominion is currently developing plans to remove coal ash ponds at power stations in the Chesapeake Bay Watershed. The removed coal ash must be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

Table 8-2 shows the compliance status of affected units:[106]

Table 8-2 Compliance status of affected units

Plant	CCR Compliance Status
Bremo Bluff Power Station	As of April 2020, ash has been removed from the East and West Ponds. Plans for closure by removal of ash from the remaining North Pond impoundment are under development and will be addressed by the Virginia DEQ in a separate future permitting action.
Chesapeake Energy Center	The facility is currently developing plans for closure by removal of ash from the landfill, historical area, and impoundment.
Chesterfield Power Station	Dominion Energy Virginia submitted the required solid waste permit application for closure by removal and groundwater monitoring of the Upper and Lower Ash Ponds in February 2020, and it is currently under review. The application outlines the removal of ash to either an offsite permitted landfill or offsite beneficial reuse. The application estimates that it will take approximately 13 years to complete closure by removal activities.
Clinch River Power Station	The ash pond was closed and capped prior to January 1, 2019. Clinch River Plant ceased burning coal in 2015 and no longer produces CCR material. The Plant now uses natural gas as fuel. All units are currently being monitored and maintained in post-closure care.
Clover Power Station	The station also has had a permitted CCR landfill since 1993. The permit is currently under revision to incorporate EPA CCR Rule requirements applicable to existing landfills.
Possum Point	As of June 2019, ash has been removed from Ponds A, B, C, and E. Plans for closure by removal of ash from the remaining impoundment (Pond D) are under development. Closure by removal of Pond D will be addressed in a future and separate DEQ permitting action.

On March 30, 2020, in response to a statutory mandate,[107] the Illinois Environmental Protection Agency (Illinois EPA) proposed rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[108] The proposed rules contain standards for the storage and disposal

98 Gavin Proposed Denial Order at 88; Clifty Creek Proposed Denial Order at 77.
99 Gavin Proposed Denial Order at 86; Clifty Creek Proposed Denial Order at 76–77.
100 Conditional Approval of an Alternative Closure Deadline for H.L. Spurlock Power Station, Maysville, Kentucky, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0595 (January 11, 2022) at 32.
101 *Id.* at 48–62.
102 *Proposed Conditional Approval of Alternative Closure Deadline for Mountaineer Plant*, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0842 at 53.
103 *Id.* at 55–60.
104 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Federal CCR Permit Program*, 85 Fed. Reg. 9940 (Feb. 20, 2020).
105 Va. Code § 10.1-1402.03.
106 Virginia Department of Environmental Quality website: https://www.deq.virginia.gov/permits-regulations/permits/waste/coal.
107 Ill. Public Act 101-171 (a.k.a. SB 09).
108 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.

of coal combustion residuals in surface impoundments. The proposed rules include a permitting program and are intended to meet federal standards.[109] Presumably the rules, once finalized, would be the basis for an application under RCRA allowing the Illinois EPA to also administer the federal regulatory program. The Illinois EPA has identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[110] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[111]

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluent guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.[112] On May 15, 2020, GenOn announced its decision to retire the Dickerson Generating Station.[113] Dickerson Generating Station was retired effective August 13, 2020. The Chalk Point coal units were retired effective June 1, 2021. On June 9, 2021, GenOn reported that it would retire its Morgantown coal fired unit by May 31, 2022, five years earlier than previously announced.[114]

109 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845) ("Proposed Illinois CCR Rules").
110 Proposed Illinois Rules at 3.
111 *Id.* at 3.
112 See Potomac Riverkeeper Network, Press Release, "Maryland Proposes to Reject Effort to Delay Pollution Reductions" (Posted April 4, 2020), <https://www.potomacriverkeepernetwork.org/maryland-proposes-to-reject-effort-to-delay-pollution-reductions/>.
113 See "GenOn Holdings, Inc. Announces Retirement of Dickerson Coal Plant" (May 15, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-dickerson-coal-plant>.
114 See "GenOn Holdings, LLC Announces Retirement of Three Coal-Fired Power Plants" (June 9, 2021) <https://www.genon.com/genon-news/genon-holdings-llc-announces-retirement-of-three-coal-fired-power-plants>.

State Environmental Regulation

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[115]

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, Illinois Governor J.B. Pritzker signed the Climate and Equitable Jobs Act (CEJA). 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.[116] [117] New investor owned, gas-fired units will have emissions caps after three years. The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO2e and co-pollutants.[118] [119] The resultant emissions caps are very low for some units and much higher for others. More than 10,000 MW of capacity is currently affected, about half of which have requested that the MMU calculate a unit specific opportunity cost. The MMU is calculating opportunity costs for units that make requests and provide required data.

  In addition to the provisions creating nuclear subsidies, mandating closure of fossil fuel generation by 2045, and limiting emissions from natural gas-fired resources, the CEJA includes provisions promoting the development of batteries and utility scale solar at the sites of up to five

115 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."
116 Letter of John J. Kim, Director, Illinois Environmental Protection Agency, to Dr. Joseph Bowring, Market Monitor (January 21, 2022) ("IEPA January 21st Letter") <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IL_EPA_CEJA_Response_to_the_IMM_20220121.pdf>.
117 The IEPA January 21st Letter explains: "All of this information is already reported to USEPA by sources subject to Section k-5, per 40 CFR Part 98, and Illinois does not intend for any changes in existing methodologies in that regard. Specifically, Part 98.2(a)(1) requires Part 98 reporting of sources that are subject to Part 75. CO2e emissions are calculated using Equation A-1 from 40 CFR 98.2(b)(4), and emissions data for specific contributing pollutants are taken from a combination of CEMS data and other measurement or estimation methods. Part 98.3 requires reporting of CO2, CH4, N2O, and each fluorinated GHG. This covers all pollutants used to calculate CO2e that would be emitted by sources subject to Section k-5. Part 75.13 requires use of CO2 CEMS or alternate methods that are acceptable continuous monitoring methods detailed in Appendices F and G to Part 75. Part 98 Tables C-1 and C-2 have default values for CH4, N2O, and other GHGs, based on fuel type, that sources should continue to use for requirements pursuant to Section k-5; they are essentially considered to be continuous parameter monitoring based on fuel consumption."
118 Carbon dioxide equivalent (CO2e) emissions means the total emissions of six greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride). Co-pollutants mean the six criteria pollutants identified by the US EPA pursuant to the Clean Air Act: Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particle Pollution, and Sulfur Dioxide.
119 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.

closed coal plants, two of which may be located in PJM. CEJA grants a subsidy of $110,000/MW for battery projects with at least 37 MW of capacity, capped at $28 million per year. A solar resource at a defined site may elect to receive either the battery subsidies or to sell premium RECs for $30 each.

On August 4, 2022, J-Power USA filed a complaint in Illinois state court concerning the application of pollutant caps to its 1,350 MW Elwood Power Plant based on historical operations.[120] The court granted an injunction, finding: "The compliance rule is arbitrary and capricious because it demands compliance prior to IEPA's announcement of how emissions caps were to be calculated. IEPA's rule, issued in January 2022, declared that 'any 12-month period' meant a rolling, 12-month calculation, starting with the period October 2021 through September 2022. Prior to January 2022, energy producers did not have the necessary information to calculate their emissions caps or monitor their ongoing emissions for CEJA purposes."[121] The injunction does not appear to affect core provisions of CEJA going forward.

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules. New Jersey addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.

- **Illinois Air Quality Standards (NO_x, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_x, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

Some states have enacted legislation or have pending legislation designed to reduce or eliminate greenhouse gas and other emissions, summarized in Table 8-3.

120 See Elwood Energy LLC v. Illinois EPA, Case No. 2022-CH-50 (Ill. 7th Jud. Cir. Court).
121 *Id.* at 17.

Table 8-3 Summary of environmental regulatory activity impacting PJM resources by jurisdiction

Jurisdiction	Bill/Docket No.	Environmental Regulatory Activity
Delaware	SB 305	151st General Assembly: The Delaware Climate Change Solutions Act would follow the issuance of Delaware's Climate Action Plan in 2021, and would establish a statutory requirement of greenhouse gas emissions reductions over the medium and long term, establishing a mandatory plan to achieve those emissions reductions and develop resilience strategies, and requiring State agencies to address climate change in decision-making and rulemaking.
Illinois	Pub. Act 102-1031 (SB 3866)	Enacted May 27, 2022: Amends the Energy Transition Act, providing that Climate Works Hubs shall be awarded grants in multi-year increments not to exceed 36 months with the opportunity for grant renewal and modification for subsequent years, subject to certain equity, union preference and worker training rules. Amends the Illinois Power Agency Act, to exempt certain units from compliance with the Agency's long-term renewable resources plan.
	SB 5589	102nd General Assembly: Amends the Public Utilities Act to delete ban on constructing nuclear power plants without a national waste disposal plan or the specific approval of the General Assembly.
	SB 5750	102nd General Assembly: Provides that all EGUs that use coal as a fuel and are public GHG-emitting units shall permanently reduce COe emissions to zero no later than December 31, 2045, extending the current 2035 deadline.
Indiana	Pub. Law 155 (SB 271)	Enacted March 18, 2022: Directs the IURC to adopt rules not later than July 1, 2023, for issuing certificates of public convenience and necessity for the development of small modular nuclear reactors. The IURC must consider in the evaluation of petitions (i) the displacement of capacity from coal or natural gas facilities and (ii) the redevelopment of sites where retired facilities are located.
	Pub. Law 120 (HB 1226)	Enacted March 14, 2022: Requires the Indiana Recycling Market Development Board to award up to $4,000,000 to applicants chosen to participate in a solid waste diversion pilot project limited to Marion County. The Department of Environmental Management must make recommendations on applications to the board on or before December 1, 2022. Requires the rules board to expeditiously adopt by rule all waste regulation exemptions or exclusions as adopted by the US EPA.
	Pub. Law 152 (SB 147)	Enacted March 18, 2022: Adds underground pumped storage hydropower to the technologies that qualify as "clean energy resources" for purposes of the statute governing the Indiana voluntary clean energy portfolio standard program. Provides that this technology qualifies as a "renewable energy resource" for purposes of the statute providing certain financial investment incentives.
Kentucky		No current activity.
Maryland	SB 526	Enacted May 29, 2022: Altering the application of the offshore wind energy component of the renewable energy portfolio standard to apply only to distribution sales of electric companies; altering the manner in which an electric company may reflect and recover offshore wind renewable energy credit costs; altering certain compliance fees for shortfalls from the offshore wind energy component of the renewable energy portfolio standard; etc.
	SB 528	Enacted April 8, 2022: Climate Solutions Now Act of 2022 requires, e.g., a reduction of statewide greenhouse gas emissions by 60 percent from 2006 levels by 2031 and net-zero emissions by 2045.
Michigan		No current activity.
New Jersey	AB 3079	2022-2023 Reg. Sess.: Requires, by energy year 2050, all electric power sold in NJ by each electric power supplier and basic generation service provider to be from zero-carbon sources.
	SB 2185	2022-2023 Reg. Sess.: Requires BPU to develop program to incentivize installation of new energy storage systems.
	SB 1170/AB 1440	2022-2023 Reg. Sess.: Requires that all new residential and commercial developments be zero energy ready and that developers to offer zero energy construction.
	AB 1744	2022-2023 Reg. Sess.: Revises law concerning Class I and solar renewable energy portfolio standards, solar renewable energy certificates, and net metering.
	SCR 17	2022-2023 Reg. Sess.: Amends Constitution to prohibit construction of new fossil fuel power plants.
	SB 1384	2022-2023 Reg. Sess.: Establishes Nuclear Power Advisory Commission.
	AB 4782	2022-2023 Reg. Sess.: Increases the goal for the annual capacity of solar energy projects to be developed under the permanent Community Solar Energy Program from 50 to 500 megawatts per year.
	AB 4658	2022-2023 Reg. Sess.: Revises State renewable energy portfolio standards.
North Carolina	SB 702	2021-2022 Reg. Sess: Establishes state clean energy goal for 2050 from renewable energy resources by December 31, 2050, that 100 percent of the total retail sales of electricity in North Carolina shall be generated from renewable energy resources by December 31, 2050.
	Ch. SL 2021-165 (HB 951)	Enacted October 31, 2021: Requires the NCUC to take steps needed to get North Carolina a 70 percent reduction in carbon emission by the year 2030 and to carbon neutrality by 2050.
Ohio	HB 429	134th General Assembly: Requires the Ohio EPA to establish a goal for a 50 percent reduction in greenhouse gas emissions from electricity by 2030, compared to a 2005 baseline, increasing to 100 percent by 2050, and to design rules to achieve that goal. Includes provisions reducing regulatory restrictions on renewables projects, inhibiting corruption, enhancing consumer protections, and promoting equity.
	HB 317	134th General Assembly: Repeals electric security plans (ESPs) under which an electric distribution utility (EDU) provides customers in its certified territory a standard service offer (SSO) of retail electric services. Requires EDUs to offer SSOs under a market rate offer (MRO).
Pennsylvania	SB 872	Reg. Sess. 2021-2022: Provides for transition to renewable energy, imposing duties on the Department of Environmental Protection and other Commonwealth agencies relating to energy consumption and renewable energy generation, and establishing certain task forces to perform studies and associated funds.
Tennessee	SJR 892	Enacted February 28, 2022.: Requests that the TVA maintain operation of its coal-fired plants until a reliable backup is developed.
Virginia		No current activity.
Washington, D.C.	CB 240267	24th Council: Codifies the 2050 carbon neutrality commitment and adds interim targets for greenhouse gas reductions between 2025 and 2050. Requires the District to achieve carbon neutrality for emissions associated with District government operations by 2040.
West Virginia		No current activity.

Clean Energy Standards

In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[122] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[123] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[124]

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (as of January 1, 2021) to cap CO_2 emissions from power generation facilities.[125]

Delaware, Maryland, New Jersey, and Virginia are the only PJM states that are members of RGGI. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[126] 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.[127] [128] A decision on the merits of the appeal is pending.

122 Va. HB 1526/SB 851.
123 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
124 *Id.*
125 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.
126 "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>.
127 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/> .
128 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).

Table 8-4 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period, the 4th control period, and the first seven auctions of the 5th control period.[129] [130] The clearing price for the auction held September 7, 2022 was $13.45 per allowance (equal to one short ton of CO_2).[131] The September auction clearing price decreased 3.2 percent over the last auction clearing price of $13.90 in June 2022.

129 Each control period is three years in duration. The 3rd control period covers 2015 through 2017. The 4th control period covers 2018 through 2020. The 5th control period covers 2021 through 2023.
130 The December 2021 auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $13.00 per ton. The auctions on March 5, 2014, September 3, 2015, and December 1, 2021 are the only auctions that included CRRs.
131 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

Table 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th and 5th Control Periods[132]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold
March 11, 2015	$5.41	15,272,670		15,272,670	$5.96	13,855,137		13,855,137
June 3, 2015	$5.50	15,507,571		15,507,571	$6.06	14,068,236		14,068,236
September 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	23,019,179
December 2, 2015	$7.50	15,374,274		15,374,274	$8.27	13,947,311		13,947,311
March 9, 2016	$5.25	14,838,732		14,838,732	$5.79	13,461,475		13,461,475
June 1, 2016	$4.53	15,089,652		15,089,652	$4.99	13,689,106		13,689,106
September 7, 2016	$4.54	14,911,315		14,911,315	$5.00	13,527,321		13,527,321
December 7, 2016	$3.55	14,791,315		14,791,315	$3.91	13,418,459		13,418,459
March 8, 2017	$3.00	14,371,300		14,371,300	$3.31	13,037,428		13,037,428
June 7, 2017	$2.53	14,597,470		14,597,470	$2.79	13,242,606		13,242,606
September 8, 2017	$4.35	14,371,585		14,371,585	$4.80	13,037,686		13,037,686
December 8, 2017	$3.80	14,687,989		14,687,989	$4.19	13,324,723		13,324,723
March 14, 2018	$3.79	13,553,767		13,553,767	$4.18	12,295,774		12,295,774
June 13, 2018	$4.02	13,771,025		13,771,025	$4.43	12,492,867		12,492,867
September 9, 2018	$4.50	13,590,107		13,590,107	$4.96	12,328,741		12,328,741
December 5, 2018	$5.35	13,360,649		13,360,649	$5.90	12,120,580		12,120,580
March 13, 2019	$5.27	12,883,436		12,883,436	$5.81	11,687,660		11,687,660
June 5, 2019	$5.62	13,221,453		13,221,453	$6.19	11,994,304		11,994,304
September 4, 2019	$5.20	13,116,447		13,116,447	$5.73	11,899,044		11,899,044
December 4, 2019	$5.61	13,116,444		13,116,444	$6.18	11,899,041		11,899,041
March 11, 2020	$5.65	16,208,347		16,208,347	$6.23	14,703,969		14,703,969
June 3, 2020	$5.75	16,336,298		16,336,298	$6.34	14,820,045		14,820,045
September 2, 2020	$6.82	16,192,785		16,192,785	$7.52	14,689,852		14,689,852
December 2, 2020	$7.41	16,237,495		16,237,495	$8.17	14,730,412		14,730,412
March 3, 2021	$7.60	23,467,261		23,467,261	$8.38	21,289,147		21,289,147
June 2, 2021	$7.97	22,987,719		22,987,719	$8.79	20,854,114		20,854,114
September 8, 2021	$9.30	22,911,423		22,911,423	$10.25	20,784,899		20,784,899
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190
March 9, 2022	$13.50	21,761,269		21,761,269	$14.88	19,741,497		19,741,497
June 1, 2022	$13.90	22,280,473		22,280,473	$15.32	20,212,511		20,212,511
September 7, 2022	$13.45	22,404,023		22,404,023	$14.83	20,324,594		20,324,594

The RGGI auction held on September 7, 2022, generated $301.3 million in auction revenue. RGGI auctions have generated $5.6 billion in auction revenue since 2008.[133] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2020 reporting year, have invested $3.0 billion (79.0 percent of revenues), approximately 53 percent on energy efficiency, 14 percent on clean and renewable energy, 8 percent on greenhouse gas abatement and 16 percent on direct bill assistance.[134]

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2021 CO_2 emission levels and the RGGI clearing price for the September 2022 auction ranges from $2.0 billion per year to $3.8 billion per year depending on associated reductions in carbon emission levels (Table 8-5).[135] Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2021 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-5 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2021 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[136]

132 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results> (Accessed October 17, 2022).
133 See Auction Results at <https://www.rggi.org/>.
134 *The Investment of RGGI Proceeds in 2020*, The Regional Greenhouse Gas Initiative (RGGI), May 2022, <https://www.rggi.org/investments/proceeds-investments>.
135 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.
136 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.

Table 8-5 Estimated CO_2 allowance revenue at September 2022 RGGI price level[137] [138]

		Estimated CO_2 allowance revenue ($ millions), carbon price $13.45 per short ton					
Jurisdiction	2021 power generation CO_2 emissions (short tons)	5 percent reduction below 2021 emission levels	10 percent reduction below 2021 emission levels	15 percent reduction below 2021 emission levels	20 percent reduction below 2021 emission levels	25 percent reduction below 2021 emission levels	50 percent reduction below 2021 emission levels
Delaware	1,569,515.5	$20.1	$19.0	$17.9	$16.9	$15.8	$10.6
Illinois	20,545,590.8	$262.5	$248.7	$234.9	$221.1	$207.3	$138.2
Indiana	27,066,021.8	$345.8	$327.6	$309.4	$291.2	$273.0	$182.0
Kentucky	23,972,416.9	$306.3	$290.2	$274.1	$257.9	$241.8	$161.2
Maryland	10,527,468.1	$134.5	$127.4	$120.4	$113.3	$106.2	$70.8
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	8,424,107.9	$107.6	$102.0	$96.3	$90.6	$85.0	$56.7
North Carolina	61,960.5	$0.8	$0.8	$0.7	$0.7	$0.6	$0.4
Ohio	62,670,551.1	$800.8	$758.6	$716.5	$674.3	$632.2	$421.5
Pennsylvania	67,579,691.3	$863.5	$818.1	$772.6	$727.2	$681.7	$454.5
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	22,491,149.9	$287.4	$272.3	$257.1	$242.0	$226.9	$151.3
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	51,728,460.2	$661.0	$626.2	$591.4	$556.6	$521.8	$347.9
Total	296,636,934.0	$3,790.3	$3,590.8	$3,391.3	$3,191.8	$2,992.3	$1,994.9

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-6 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2022 compliance year is the second year of the fifth control period.

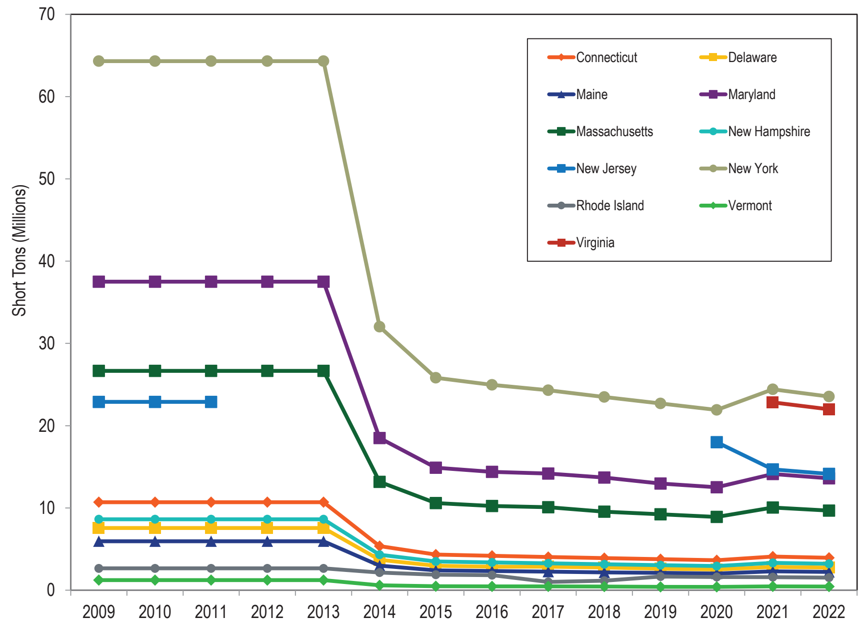
In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[139] [140] The first adjustment removed 57.5 allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.[141] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13.7 million allowances per year and was in place through 2020.[142] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[143] The base emissions cap for each of the next five years will be reduced by 19.1 million allowances. The percent change columns in Table 8-6 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[144] The adjusted emissions cap for 2021 is the only year for which the adjusted carbon emissions cap increased.[145] Figure 8-2 shows the adjusted carbon budgets for the RGGI states. The RGGI clearing price since 2014 has been on average 177.8 percent higher than the prices prior to the emission cap adjustments.

137 The 2020 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.
138 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-3 do not reflect offset allowances.
139 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.
140 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.
141 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014) at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.
142 Id.
143 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.
144 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the RGGI cap for 2021 reflects the impact of New Jersey rejoining RGGI in 2020 but the percent change from 2019 to 2020 does not include New Jersey's allowance budget. Virginia's adoption of RGGI in 2021 is treated analogously.
145 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.

Table 8-6 RGGI emissions cap history[146 147 148]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009	1st	$2.77	188,076,976		188,076,976	
2010		$1.93	188,076,976	0.0%	188,076,976	0.0%
2011		$1.89	188,076,976	0.0%	188,076,976	0.0%
2012	2nd	$1.93	165,184,246	0.0%	165,184,246	0.0%
2013		$2.92	165,184,246	0.0%	165,184,246	0.0%
2014		$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015	3rd	$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016		$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018	4th	$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019		$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020		$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021	5th	$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022		$13.62	116,112,784	(3.1%)	97,022,454	(3.6%)
2023			112,457,784	(3.1%)	93,367,454	(3.8%)

Figure 8-2 RGGI adjusted carbon budgets by state[149]



If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-7 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. Allowance revenues to states would be $1.5 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2021.

146 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed October 18, 2021).
147 RGGI budgets for 2022 and 2023 are found in a RGGI press release, "Third Adjustment for Banked Allowances Announcement," March 15, 2021 <https://www.rggi.org/news-releases/rggi-releases>.
148 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

149 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed October 18, 2022).

Table 8-7 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
Jurisdiction	5 percent reduction below 2021 emission levels	10 percent reduction below 2021 emission levels	15 percent reduction below 2021 emission levels	20 percent reduction below 2021 emission levels	25 percent reduction below 2021 emission levels	50 percent reduction below 2021 emission levels
Carbon Price ($ per short ton)					$10.00	
Delaware	$14.9	$14.1	$13.3	$12.6	$11.8	$7.8
Illinois	$195.2	$184.9	$174.6	$164.4	$154.1	$102.7
Indiana	$257.1	$243.6	$230.1	$216.5	$203.0	$135.3
Kentucky	$227.7	$215.8	$203.8	$191.8	$179.8	$119.9
Maryland	$100.0	$94.7	$89.5	$84.2	$79.0	$52.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$80.0	$75.8	$71.6	$67.4	$63.2	$42.1
North Carolina	$0.6	$0.6	$0.5	$0.5	$0.5	$0.3
Ohio	$595.4	$564.0	$532.7	$501.4	$470.0	$313.4
Pennsylvania	$642.0	$608.2	$574.4	$540.6	$506.8	$337.9
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$213.7	$202.4	$191.2	$179.9	$168.7	$112.5
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$491.4	$465.6	$439.7	$413.8	$388.0	$258.6
Total	$2,818.1	$2,669.7	$2,521.4	$2,373.1	$2,224.8	$1,483.2
Carbon Price ($ per short ton)					$25.00	
Delaware	$37.3	$35.3	$33.4	$31.4	$29.4	$19.6
Illinois	$488.0	$462.3	$436.6	$410.9	$385.2	$256.8
Indiana	$642.8	$609.0	$575.2	$541.3	$507.5	$338.3
Kentucky	$569.3	$539.4	$509.4	$479.4	$449.5	$299.7
Maryland	$250.0	$236.9	$223.7	$210.5	$197.4	$131.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$200.1	$189.5	$179.0	$168.5	$158.0	$105.3
North Carolina	$1.5	$1.4	$1.3	$1.2	$1.2	$0.8
Ohio	$1,488.4	$1,410.1	$1,331.7	$1,253.4	$1,175.1	$783.4
Pennsylvania	$1,605.0	$1,520.5	$1,436.1	$1,351.6	$1,267.1	$844.7
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$534.2	$506.1	$477.9	$449.8	$421.7	$281.1
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,228.6	$1,163.9	$1,099.2	$1,034.6	$969.9	$646.6
Total	$7,045.1	$6,674.3	$6,303.5	$5,932.7	$5,561.9	$3,708.0
Carbon Price ($ per short ton)					$50.00	
Delaware	$74.6	$70.6	$66.7	$62.8	$58.9	$39.2
Illinois	$975.9	$924.6	$873.2	$821.8	$770.5	$513.6
Indiana	$1,285.6	$1,218.0	$1,150.3	$1,082.6	$1,015.0	$676.7
Kentucky	$1,138.7	$1,078.8	$1,018.8	$958.9	$899.0	$599.3
Maryland	$500.1	$473.7	$447.4	$421.1	$394.8	$263.2
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$400.1	$379.1	$358.0	$337.0	$315.9	$210.6
North Carolina	$2.9	$2.8	$2.6	$2.5	$2.3	$1.5
Ohio	$2,976.9	$2,820.2	$2,663.5	$2,506.8	$2,350.1	$1,566.8
Pennsylvania	$3,210.0	$3,041.1	$2,872.1	$2,703.2	$2,534.2	$1,689.5
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,068.3	$1,012.1	$955.9	$899.6	$843.4	$562.3
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,457.1	$2,327.8	$2,198.5	$2,069.1	$1,939.8	$1,293.2
Total	$14,090.3	$13,348.7	$12,607.1	$11,865.5	$11,123.9	$7,415.9

Table 8-8 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $25.00 per tonne, the PJM load-weighted average LMP in the first nine months of 2022 would have increased by 1.6 percent.[150]

Table 8-8 Estimated impact of carbon price on LMP: January through September, 2021 and 2022

		2021 (Jan - Sep)			2022 (Jan - Sep)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$35.68	$35.98	0.8%	$77.84	$76.87	(1.2%)
Scenario 2	$10.00	$35.68	$37.96	6.4%	$77.84	$77.43	(0.5%)
Scenario 3	$15.00	$35.68	$39.95	12.0%	$77.84	$77.99	0.2%
Scenario 4	$25.00	$35.68	$43.91	23.1%	$77.84	$79.10	1.6%
Scenario 5	$50.00	$35.68	$53.83	50.9%	$77.84	$81.89	5.2%

Table 8-9 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[151] [152] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP). Table 8-11 and Table 8-12 show the carbon price impact ($ per MWh) for a range of heat rates and carbon prices for natural gas and coal fired generation.

Table 8-9 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.44	$4.89	$7.33	$24.45	$48.89	$97.79	$195.58
CC	$1.67	$3.33	$5.00	$16.66	$33.31	$66.62	$133.25
CP	$4.31	$8.62	$12.93	$43.09	$86.18	$172.36	$344.73

Table 8-9 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $204.23 per credit in the first nine months of 2022. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If the MWh produced by the solar resource resulted in avoiding the production of one MWh from a CT, the value of carbon reduction implied by the SREC price is a carbon price slightly more than $400 per tonne since the price of the SREC is slightly higher than the carbon price per MWh for a CT ($195.58). This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $24.45 per MWh.

Applying this method to Tier I and Class I REC and SREC price histories yields the implied carbon prices in Table 8-10. The carbon price implied by the average REC price during the first nine months of 2022 in Washington, DC is $18.42 per tonne which is $3.41 per tonne higher than the average RGGI auction price of $15.01 per tonne. The carbon price implied by the average price for Ohio RECs in 2022 is $18.05 per tonne and implied carbon price for Virginia RECs is $19.22 per tonne. The implied carbon prices for Maryland, New Jersey and Pennsylvania RECs are well above the RGGI clearing price, and well below the social cost of carbon which is estimated to be in the range of $50 per tonne.[153] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices, and all exceed the social cost of carbon.

150 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

151 Heat rates from: *2021 State of the Market Report for PJM: January through June*, Section 7: Net Revenue, Table 7-3.

152 Prices reflect carbon emissions rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

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

Table 8-10 Implied carbon price based on REC and SREC prices: 2009 through September 2022

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Jurisdiction with Tier I or Class I REC	**Carbon Price ($ per tonne) Implied by REC Prices**													
Delaware					$34.26	$35.28	$26.33	$23.64	$10.29	$11.60	$16.10	$19.94		
Maryland	$2.08	$1.93	$3.07	$6.36	$17.51	$28.54	$29.27	$26.17	$23.19	$21.35	$17.81	$19.98	$24.97	$27.65
New Jersey	$13.38	$17.79	$8.60	$4.75	$13.13	$21.10	$25.37	$27.01	$24.08	$22.08	$19.25	$20.54	$24.72	$26.17
Ohio						$10.19	$5.91	$4.03	$6.29	$11.21	$14.04	$16.33	$17.12	$17.14
Pennsylvania	$6.84	$8.16	$3.34	$4.31	$15.92	$26.74	$28.96	$26.43	$23.42	$21.53	$17.96	$20.06	$24.33	$27.34
Virginia													$18.62	$19.22
Washington, D.C.							$3.20	$4.05	$4.90	$4.69	$5.52	$11.82	$15.14	$18.42
Jurisdiction with Solar REC	**Carbon Price ($ per tonne) Implied by Solar REC Prices**													
Delaware						$117.60	$85.66	$86.75	$35.80	$17.38				
Maryland		$547.76	$496.04	$383.73	$305.46	$293.59	$251.99	$183.64	$128.05	$87.27	$84.19	$101.68	$120.77	$107.41
New Jersey	$1,376.52	$1,356.24	$1,312.96	$538.70	$346.98	$327.20	$389.91	$425.49	$460.60	$446.35	$410.31	$394.18	$406.60	$417.70
Ohio						$82.56	$45.25	$36.26	$31.92	$21.73	$26.65			
Pennsylvania	$611.89	$592.36	$379.82	$102.11	$68.55	$76.13	$67.09	$55.22	$43.97	$28.16	$51.65	$63.80	$72.27	$84.74
Washington, D.C.	$715.14	$437.60	$503.14	$657.50	$959.44	$960.35	$997.05	$996.49	$868.79	$842.89	$851.39	$869.41	$847.22	$847.59
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ per tonne)**													
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$10.59	$15.01

Table 8-11 Carbon price for natural gas fired generators[154]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
6,000	$3.17	$4.76	$6.35	$7.94	$9.52	$11.11	$12.70	$14.29	$15.87	$17.46	$19.05
6,500	$3.44	$5.16	$6.88	$8.60	$10.32	$12.04	$13.76	$15.48	$17.20	$18.92	$20.63
7,000	$3.70	$5.56	$7.41	$9.26	$11.11	$12.96	$14.81	$16.67	$18.52	$20.37	$22.22
7,500	$3.97	$5.95	$7.94	$9.92	$11.90	$13.89	$15.87	$17.86	$19.84	$21.83	$23.81
8,000	$4.23	$6.35	$8.47	$10.58	$12.70	$14.81	$16.93	$19.05	$21.16	$23.28	$25.40
8,500	$4.50	$6.75	$8.99	$11.24	$13.49	$15.74	$17.99	$20.24	$22.49	$24.74	$26.98
9,000	$4.76	$7.14	$9.52	$11.90	$14.29	$16.67	$19.05	$21.43	$23.81	$26.19	$28.57
9,500	$5.03	$7.54	$10.05	$12.57	$15.08	$17.59	$20.11	$22.62	$25.13	$27.65	$30.16
10,000	$5.29	$7.94	$10.58	$13.23	$15.87	$18.52	$21.16	$23.81	$26.45	$29.10	$31.75
10,500	$5.56	$8.33	$11.11	$13.89	$16.67	$19.44	$22.22	$25.00	$27.78	$30.56	$33.33
11,000	$5.82	$8.73	$11.64	$14.55	$17.46	$20.37	$23.28	$26.19	$29.10	$32.01	$34.92
11,500	$6.08	$9.13	$12.17	$15.21	$18.25	$21.30	$24.34	$27.38	$30.42	$33.47	$36.51
12,000	$6.35	$9.52	$12.70	$15.87	$19.05	$22.22	$25.40	$28.57	$31.75	$34.92	$38.10
12,500	$6.61	$9.92	$13.23	$16.53	$19.84	$23.15	$26.45	$29.76	$33.07	$36.38	$39.68
13,000	$6.88	$10.32	$13.76	$17.20	$20.63	$24.07	$27.51	$30.95	$34.39	$37.83	$41.27
13,500	$7.14	$10.71	$14.29	$17.86	$21.43	$25.00	$28.57	$32.14	$35.71	$39.29	$42.86
14,000	$7.41	$11.11	$14.81	$18.52	$22.22	$25.93	$29.63	$33.33	$37.04	$40.74	$44.44
14,500	$7.67	$11.51	$15.34	$19.18	$23.02	$26.85	$30.69	$34.52	$38.36	$42.20	$46.03
15,000	$7.94	$11.90	$15.87	$19.84	$23.81	$27.78	$31.75	$35.71	$39.68	$43.65	$47.62

154 Prices reflect carbon emission rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

Table 8-12 Carbon price for coal fired generators[155]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
9,000	$8.39	$12.58	$16.77	$20.96	$25.16	$29.35	$33.54	$37.73	$41.93	$46.12	$50.31
9,500	$8.85	$13.28	$17.70	$22.13	$26.55	$30.98	$35.40	$39.83	$44.26	$48.68	$53.11
10,000	$9.32	$13.98	$18.63	$23.29	$27.95	$32.61	$37.27	$41.93	$46.58	$51.24	$55.90
10,500	$9.78	$14.67	$19.57	$24.46	$29.35	$34.24	$39.13	$44.02	$48.91	$53.81	$58.70
11,000	$10.25	$15.37	$20.50	$25.62	$30.75	$35.87	$40.99	$46.12	$51.24	$56.37	$61.49
11,500	$10.71	$16.07	$21.43	$26.79	$32.14	$37.50	$42.86	$48.22	$53.57	$58.93	$64.29
12,000	$11.18	$16.77	$22.36	$27.95	$33.54	$39.13	$44.72	$50.31	$55.90	$61.49	$67.08
12,500	$11.65	$17.47	$23.29	$29.12	$34.94	$40.76	$46.58	$52.41	$58.23	$64.05	$69.88
13,000	$12.11	$18.17	$24.22	$30.28	$36.34	$42.39	$48.45	$54.50	$60.56	$66.62	$72.67
13,500	$12.58	$18.87	$25.16	$31.44	$37.73	$44.02	$50.31	$56.60	$62.89	$69.18	$75.47
14,000	$13.04	$19.57	$26.09	$32.61	$39.13	$45.65	$52.18	$58.70	$65.22	$71.74	$78.26
14,500	$13.51	$20.26	$27.02	$33.77	$40.53	$47.28	$54.04	$60.79	$67.55	$74.30	$81.06
15,000	$13.98	$20.96	$27.95	$34.94	$41.93	$48.91	$55.90	$62.89	$69.88	$76.87	$83.85
15,500	$14.44	$21.66	$28.88	$36.10	$43.32	$50.54	$57.77	$64.99	$72.21	$79.43	$86.65
16,000	$14.91	$22.36	$29.81	$37.27	$44.72	$52.18	$59.63	$67.08	$74.54	$81.99	$89.44
16,500	$15.37	$23.06	$30.75	$38.43	$46.12	$53.81	$61.49	$69.18	$76.87	$84.55	$92.24
17,000	$15.84	$23.76	$31.68	$39.60	$47.52	$55.44	$63.36	$71.27	$79.19	$87.11	$95.03
17,500	$16.30	$24.46	$32.61	$40.76	$48.91	$57.07	$65.22	$73.37	$81.52	$89.68	$97.83
18,000	$16.77	$25.16	$33.54	$41.93	$50.31	$58.70	$67.08	$75.47	$83.85	$92.24	$100.62

State Renewable Portfolio Standards

Ten of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[156] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2022, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of September 30, 2022, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties. Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[157]

As of September 30, 2022, Kentucky, Tennessee and West Virginia had no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information

155 Prices reflect carbon emission rates for refined coal in *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

156 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 23, 2019).

157 See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <https://www.in.gov/iurc/2981.htm>.

with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[158]

Table 8-13 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year.

The Climate and Equitable Jobs Act (CEJA), which became effective on September 15, 2021 in Illinois, increased the RPS target percent from 25 percent by 2025 to 40 percent by 2030. CEJA also increased the quotas for RECs sourced from new wind and new photovoltaic resources, and made changes to eligible technologies and geographic restrictions. See Table 8-14 for details.

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50.0 percent renewable by 2030.[161] Part of the legislation was to eliminate resources fueled by black liquor as a Tier 1 eligible technology. Senate Bill 65 reduced the penalty for solar non compliance from $100 per credit to $80 per credit, and extended the Tier 2 standard which was scheduled to expire with the 2020 compliance year.

Table 8-13 Renewable and alternative energy standards of PJM jurisdictions: 2021 to 2030[159 160]

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	21.00%	22.00%	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%
Illinois	19.00%	20.50%	22.00%	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%
Maryland	33.30%	32.60%	34.40%	36.20%	38.00%	40.50%	44.00%	45.50%	50.00%	52.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	6.00%	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%
Virginia (Phase II utilities)	14.00%	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard										
Indiana	7.00%	7.00%	7.00%	7.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jurisdiction with No Standard										
Kentucky	No Renewable Portfolio Standard									
Tennessee	No Renewable Portfolio Standard									
West Virginia	No Renewable Portfolio Standard									

158 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).

159 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.

160 The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.

161 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

The Delaware General Assembly passed new RPS legislation on February 10, 2021. The new law updates the Delaware RPS targets from 25 percent in 2025 to 40 percent in 2035.[162] Additional details are provided in Table 8-14.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[163] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.[164] [165] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[166] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

On May 18, 2021, Maryland enacted legislation doubling the limit on net metered capacity from 1,500 to 3,000 MW.[167] The legislation is expected to boost the installation of distribution level solar power.

162 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
163 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
164 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).
165 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
166 N.J. S. 2314/A. 3723.
167 Md. Code Ann § 7-306(d) & 7-306.2(g) (HB 569).

On July 9, 2021, New Jersey enacted legislation establishing a new program for SRECs under the BPU.[168] Through the SREC-II program, the BPU distribute solar renewable certificates to qualifying solar power facilities. The legislation includes incentives for at least 1,500 MW of behind the meter solar facilities and 750 MW of community solar by 2026. It also includes a new competitive solicitation process to incentivize at least 1,500 MW of large-scale solar power facilities by 2026, and develops siting criteria for large-scale solar projects.

Table 8-14 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

168 N.J. P.L.2021 (S. 2605/A 4554).

Table 8-14 Recent changes in RPS rules[169 170 171 172 173 174 175]

Jurisdiction	Legislation	Effective Date	Summary of changes
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[176]

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW of offshore wind capacity by 2030 (plus 2,000 MW of energy storage capacity).[177] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[178] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Orsted.[179] [180]

169 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
170 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
171 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
172 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
173 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
174 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
175 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
176 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.
177 N.J. S. 2314/A. 3723.
178 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.
179 BPU Docket No. QO18080851.
180 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

On December 17, 2021, the Maryland Public Service Commission awarded ORECs in its Round 2 solicitation to the 846 MW Skipjack Wind 2 offshore project, owned by Skipjack Offshore Energy LLC, an Orsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.[181] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[182] Both projects are expected to become operational before the end of 2026.[183] In 2017, Round 1 ORECs were awarded to Deepwater Wind's 120-MW Skipjack Wind Farm, later acquired by Orsted, and U.S. Wind's 248 MW project.[184]

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[185] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[186]

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.[187] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-15 shows the Tier I standards for PJM states.[188] All eligible technologies for the RPS standards in Table 8-15 satisfy the EIA definition of renewable energy.[189]

Table 8-15 Tier I / Class I renewable standards of PJM jurisdictions: 2021 to 2030

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	30.80%	30.10%	31.90%	33.70%	35.50%	38.00%	41.50%	43.00%	47.50%	50.00%
New Jersey	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

Delaware, Illinois, Michigan, North Carolina, Virginia and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[190]

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving

181 "Orsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-16-gw-in-maryland-offshore-tender-766237/>.
182 *Id.*
183 *Id.*
184 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).
185 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.
186 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.
187 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.
188 This includes New Jersey's Class I renewable standard.
189 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).
190 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through September 30, 2022. Tier I REC prices are lower than SREC prices. For example, the average SREC price during the first nine months of 2022 in Washington, DC was $414.42 and the average Tier I price during the first nine months of 2022 in Washington, DC was $9.01.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through September 2022

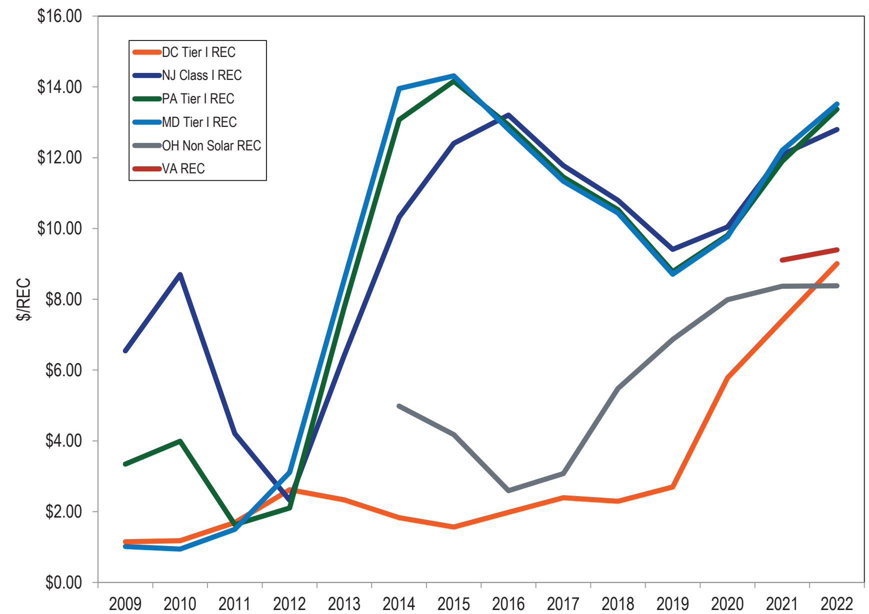


Figure 8-4 and Table 8-16 show the fulfillment of Tier I equivalent RPS requirement for 2016 through 2021 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[191] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Illinois RPS, beginning in 2019, is fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of imported and local carbon producing RECs and imported and local noncarbon RECs by state to meet the RPS requirements. Table 8-16 shows the percent of imported

191 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 18, 2022). The timing of the REC retirement reports varies by state and the 2021 reporting year data is incomplete for some states.

and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Virginia imported 80 percent of the RECs used to satisfy the RPS in 2021, its first year with a mandatory RPS, and 80.7 percent of the Virginia's 2021 RECs were carbon free. Ohio met its RPS target using 85.9 percent imported RECs, and 14.1 percent State RECs for the 2021 compliance year. Ohio met its RPS target using 74.9 percent noncarbon producing RECs, and 25.1 percent carbon producing RECs for the 2021 compliance year. Illinois met its RPS target using 19.0 percent imported RECs, and 81.0 percent State RECs for the 2021 compliance year. Illinois met its RPS target using 100.0 percent noncarbon producing RECs for the 2019, 2020 and 2021 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2016 through 2021

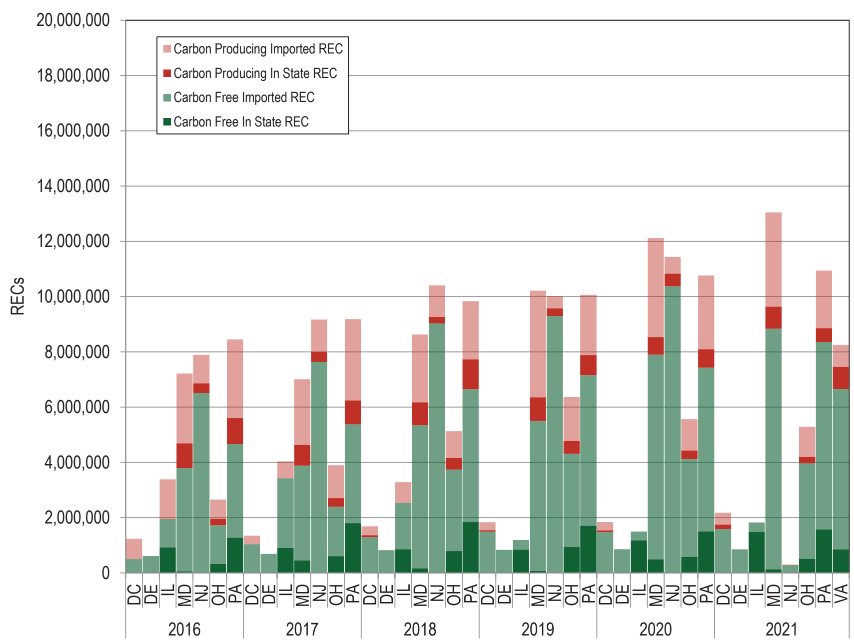


Table 8-16 State fulfillment of Tier I equivalent RPS: 2016 through 2021

		Carbon Free REC		Carbon Producing REC	
Year	REC Type	In State	Import	In State	Import
2016	DE New Eligible	1.0%	99.0%	0.0%	0.0%
	DC Tier I	0.0%	40.5%	0.0%	59.5%
	OH Renewable Energy Source	12.3%	52.8%	8.7%	26.2%
	IL Renewable	27.1%	30.3%	0.1%	42.5%
	MD Tier I	0.8%	51.7%	12.5%	35.0%
	NJ Class I	0.0%	82.5%	4.5%	13.0%
	PA Tier I	15.1%	40.2%	11.1%	33.7%
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%
2018	DE New Eligible	0.4%	99.6%	0.0%	0.0%
	DC Tier I	0.0%	76.5%	4.5%	19.0%
	OH Renewable Energy Source	15.4%	57.4%	8.3%	18.9%
	IL Renewable	26.1%	51.0%	0.0%	22.9%
	MD Tier I	1.9%	60.1%	9.6%	28.5%
	NJ Class I	0.0%	86.7%	2.3%	11.0%
	PA Tier I	18.7%	48.9%	10.9%	21.4%
2019	DE New Eligible	0.3%	99.7%	0.0%	0.0%
	DC Tier I	0.0%	81.5%	2.8%	15.7%
	OH Renewable Energy Source	14.7%	53.0%	7.3%	25.0%
	IL Renewable	70.5%	29.5%	0.0%	0.0%
	MD Tier I	0.7%	53.2%	8.4%	37.8%
	NJ Class I	0.1%	92.7%	2.8%	4.4%
	PA Tier I	17.0%	54.2%	7.2%	21.7%
2020	DE New Eligible	0.9%	99.1%	0.0%	0.0%
	DC Tier I	0.0%	80.1%	3.3%	16.6%
	OH Renewable Energy Source	10.5%	63.5%	5.5%	20.5%
	IL Renewable	78.3%	21.7%	0.0%	0.0%
	MD Tier I	4.1%	61.1%	5.3%	29.6%
	NJ Class I	0.1%	90.6%	4.0%	5.3%
	PA Tier I	13.9%	55.1%	6.2%	24.8%
2021	DE New Eligible	0.0%	99.2%	0.8%	0.0%
	DC Tier I	0.0%	72.9%	7.4%	19.7%
	OH Renewable Energy Source	9.7%	65.3%	4.4%	20.6%
	IL Renewable	81.0%	19.0%	0.0%	0.0%
	MD Tier I	1.0%	66.7%	6.1%	26.1%
	NJ Class I	0.2%	92.3%	0.3%	7.2%
	PA Tier I	14.4%	62.0%	4.6%	19.1%
	VA Renewable	10.3%	70.4%	9.7%	9.6%

Table 8-17 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-17 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-17 are included in the total RPS requirements presented in Table 8-13. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[192]

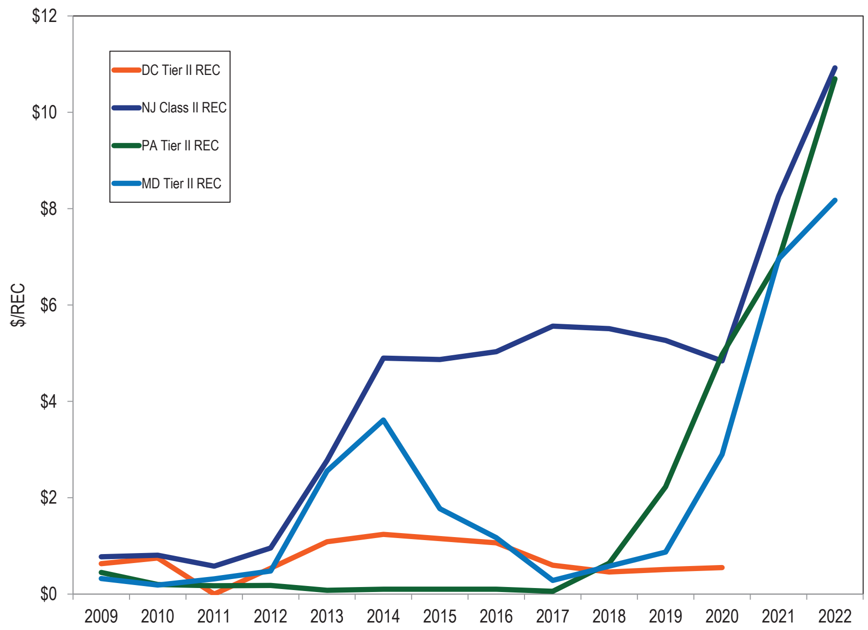
Table 8-17 Additional renewable standards of PJM jurisdictions: 2021 to 2030

Jurisdiction	Type of Standard	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	Off Shore Wind	1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.94%	1.94%
Maryland	Tier 2	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Class II	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009, through September 30, 2022. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2022. In the first nine months of 2022, the average Pennsylvania Tier II REC price was $10.69, the average New Jersey Class II REC price was $10.92 and average Maryland Tier II REC price as $8.18.[193]

192 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2 <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.
193 Tier II REC price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through September 2022



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-13 and Table 8-15 but must be met by solar RECs (SRECs) only. Table 8-18 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have or have had requirements for the proportion of load to be served by solar. The Illinois RPS specifies the number of RECs that must be sourced from photovoltaic resources energized after June 1, 2017. Recent legislation increased the SREC requirement from 2,000,000 RECs to 5,500,000 RECs in the 2021/2022 Delivery Year.[194] New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[195] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[196] The new program establishes a 15 year fixed priced Transition REC (TREC). On July 28, 2021, New Jersey Board of Public Utilities approved the Successor Solar Incentive (SuSI) Program which will provide incentives for 3,750 MW of new solar generation by 2026.[197] Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[198] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.[199] The Delaware General Assembly passed new RPS legislation on February 10, 2021 that increased the solar carve out target from 3.5 percent in 2025 to 10.0 percent in 2035.[200]

194 See amendments to Sec. 1-75(c)(1)(C) of the Illinois Power Agency Act contained in Section 90-30 of Public Act 102-0662.

195 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).

196 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.

197 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.

198 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

199 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

200 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

Table 8-18 Solar renewable standards by percent of electric load for PJM jurisdictions: 2021 to 2030[201]

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	2.50%	2.75%	3.00%	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%
Illinois (RECs)	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	24,750,000
Maryland	7.50%	5.50%	6.00%	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%
Michigan	No Minimum Solar Requirement									
New Jersey	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	No Minimum Solar Requirement									
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%
Jurisdiction with Voluntary Standard										
Indiana	No Minimum Solar Requirement									
Virginia	No Minimum Solar Requirement									
Jurisdiction with No Standard										
Kentucky	No Renewable Portfolio Standard									
Tennessee	No Renewable Portfolio Standard									
West Virginia	No Renewable Portfolio Standard									

Figure 8-6 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through September 30, 2022. The average NJ SREC price was $204.23 in the first nine months of 2022. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, DC SREC price was $414.42 per SREC in the first nine months of 2022.[202]

201 The Illinois solar standard currently requires 5.5 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 102-0662, September 15, 2021.
202 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com> (Accessed October 18, 2022).

Figure 8-6 Average SREC price by jurisdiction: 2009 through September 2022

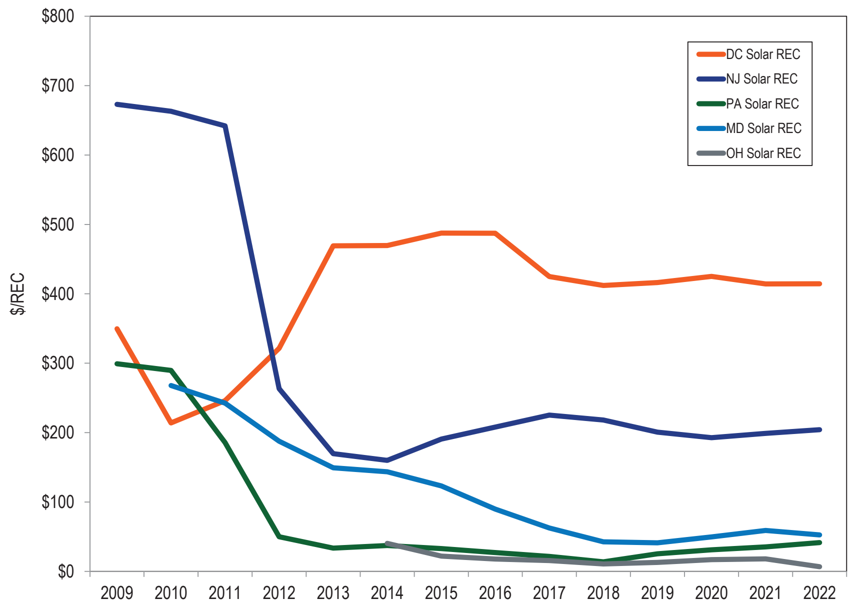


Figure 8-7 State fulfillment of Solar RPS: 2016 through 2021

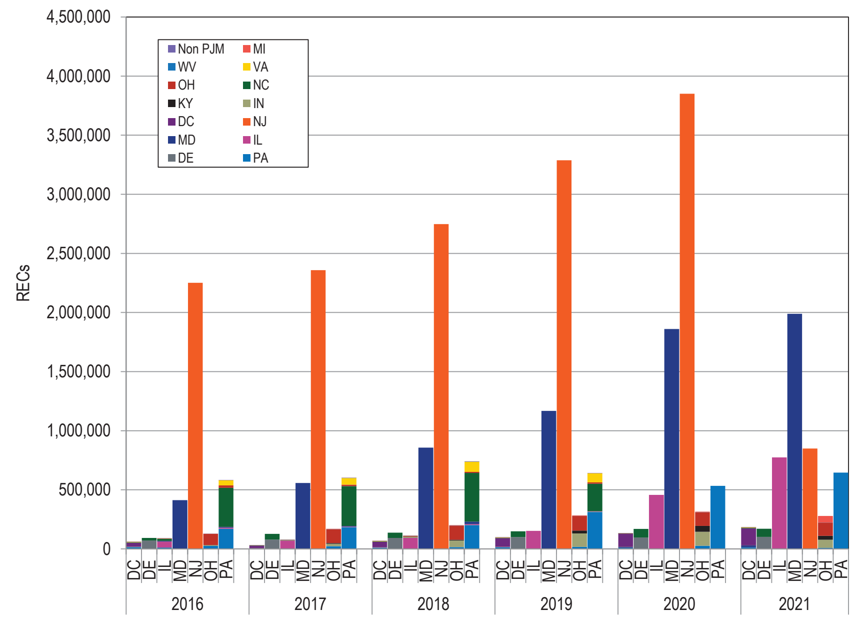


Figure 8-7 and Table 8-19 show where the SRECs originated that are used to satisfy the states' solar requirement for 2016 through 2021.[203] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-19 shows the percent of imported and local SRECs used to meet the RPS requirements. Since 2019, all SRECs used for RPS compliance in Illinois, Maryland, Pennsylvania and New Jersey have been sourced from in state solar generators.

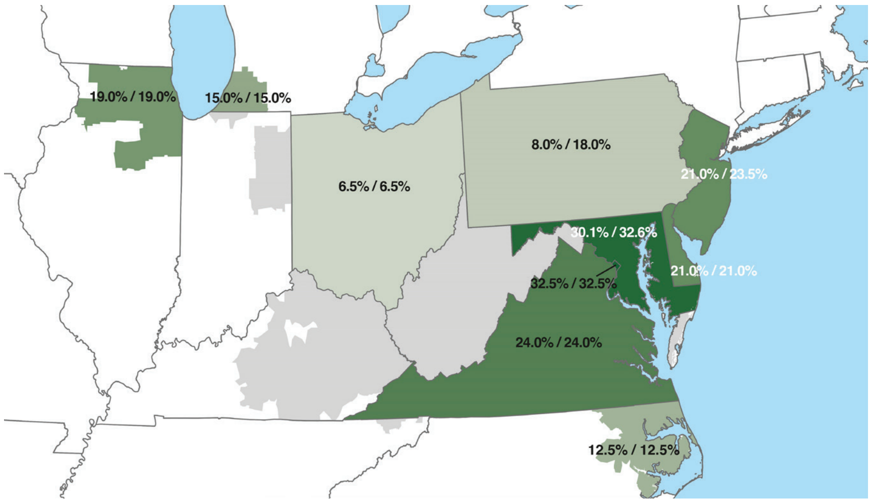
203 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 18, 2022). The timing of the REC retirement reports varies by state and the 2021 reporting year data is incomplete for some states.

Table 8-19 State fulfillment of Solar RPS: 2016 through 2021

		In State SREC	Import SREC
2016	DC Solar	49.8%	50.2%
	DE Solar Eligible	76.5%	23.5%
	IL Solar Renewable	56.5%	43.5%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	73.3%	26.7%
	PA Solar	29.1%	70.9%
2017	DC Solar	63.8%	36.2%
	DE Solar Eligible	61.9%	38.1%
	IL Solar Renewable	87.6%	12.4%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	69.0%	31.0%
	PA Solar	30.6%	69.4%
2018	DC Solar	67.4%	32.6%
	DE Solar Eligible	67.7%	32.3%
	IL Solar Renewable	82.9%	17.1%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	59.5%	40.5%
	PA Solar	27.1%	72.9%
2019	DC Solar	72.4%	27.6%
	DE Solar Eligible	67.8%	32.2%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	43.6%	56.4%
	PA Solar	48.8%	51.2%
2020	DC Solar	81.5%	18.5%
	DE Solar Eligible	56.7%	43.3%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%
	PA Solar	100.0%	0.0%
2021	DC Solar	78.0%	22.0%
	DE Solar Eligible	59.9%	40.1%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	40.2%	59.8%
	PA Solar	100.0%	0.0%

Figure 8-8 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-8, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 18.0 percent number in Figure 8-8 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2022[204]



Under the existing state renewable portfolio standards, 17.0 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first nine months of 2022. Tier I resources include landfill gas, run of river hydro, wind and solar resources. Tier II resources include pumped storage, large scale hydro, solid waste and waste coal resources. In the first nine months of 2022, 8.1 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-20. If the proportion of load among states remains constant, 30.8 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 14.6 percent of PJM load should have been served by Tier I or renewable energy resources in the first nine months of 2022. In the first nine months of 2022, 5.8 percent of PJM generation was Tier I or renewable energy. The current REC production from PJM generation resources was not enough to meet the state renewable requirements for the first nine months of 2022, and LSEs purchased RECs from outside the PJM footprint. LSEs that are unable to meet the RPS with RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 28.4 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-20 shows generation by jurisdiction and resource type for the first nine months of 2022. Wind generation was 21,865.7 GWh of 37,511.5 Tier I GWh, or 58.3 percent, in the PJM footprint. As shown in Table 8-20, 51,825.2 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 72.4 percent. Wind and solar generation (noncarbon producing) was 4.6 percent of total generation in PJM in the first nine months of 2022. Tier I generation was 5.8 percent of total generation in PJM and Tier II was 2.2 percent of total generation in PJM in the first nine months of 2022. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 15,098.2 GWh, or 29.1 percent of the total Tier I and Tier II generation.

204 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

Table 8-20 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2022

	Tier I							Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Other Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	33.9	0.0	0.0	0.0	0.0	33.9	0.0	0.0	0.0	0.0	0.0	33.9
Illinois	0.0	59.7	0.0	0.0	11.5	10,445.1	10,516.3	0.0	0.0	0.0	0.0	0.0	10,516.3
Indiana	0.0	12.5	0.0	30.1	382.3	4,562.7	4,987.6	0.0	0.0	0.0	0.0	0.0	4,987.6
Kentucky	0.0	0.0	209.4	68.9	0.0	0.0	278.3	0.0	0.0	0.0	0.0	0.0	278.3
Maryland	0.0	29.2	0.0	0.0	442.1	493.4	964.8	0.0	0.0	404.4	0.0	404.4	1,369.1
Michigan	0.0	48.4	0.0	43.8	4.0	0.0	96.2	0.0	0.0	0.0	0.0	0.0	96.2
New Jersey	0.0	83.0	4.7	0.0	758.2	8.0	853.8	332.1	0.0	926.1	0.0	1,258.2	2,112.0
North Carolina	0.0	0.0	293.0	0.0	1,773.3	409.3	2,475.6	0.0	0.0	0.0	0.0	0.0	2,475.6
Ohio	0.0	198.8	728.6	0.0	625.3	2,135.2	3,687.8	0.0	0.0	0.2	0.0	0.2	3,688.1
Pennsylvania	0.0	286.4	3,219.1	17.7	184.9	2,459.5	6,167.6	1,958.3	0.0	1,077.2	4,470.0	7,505.5	13,673.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	1,073.4	345.4	543.4	50.9	3,410.8	38.2	5,462.0	2,642.8	1,410.7	631.9	0.0	4,685.4	10,147.3
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	24.6	624.1	0.0	24.8	1,314.3	1,987.7	0.0	0.0	0.0	460.1	460.1	2,447.8
Total	1,073.4	1,121.8	5,622.2	211.4	7,617.1	21,865.7	37,511.5	4,933.1	1,410.7	3,039.9	4,930.1	14,313.7	51,825.2

Table 8-22 shows the summer installed capacity rating of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal, natural gas and oil units that qualify as Tier II because they have a secondary fuel capability that satisfies the alternative energy standards of a PJM state or jurisdiction. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when the unit is operating using the fuel listed as Tier I or Tier II. Virginia has the largest amount of solar capacity in PJM, 2,140.1 MW, or 39.0 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 8,122.1 MW, or 73.9 percent of the total wind capacity.

PJM states with RPS rely heavily on imports for RPS compliance. Table 8-21 compares each state's RPS requirement for the first nine months of 2022 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 75.1 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 67.3 percent of the Tier I RPS requirement and 65.5 percent of the Tier II RPS requirement. North Carolina generation was in excess of the RPS requirement but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation in PJM states to meet 43.7 percent of the Tier I RPS requirement and 101.3 percent of the Tier II RPS requirement for the first nine months of 2022.

Table 8-21 RPS Requirements and Generation by RPS Eligible Resources: January through September, 2022

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	33.9	2,046.0	1.7%	0.0	0.0	
Illinois	10,516.3	14,005.9	75.1%	0.0	0.0	
Indiana	4,987.6	0.0		0.0	0.0	
Kentucky	278.3	0.0		0.0	0.0	
Maryland	964.8	14,434.1	6.7%	404.4	1,198.8	33.7%
Michigan	96.2	512.3	18.8%	0.0	0.0	
New Jersey	853.8	12,663.1	6.7%	1,258.2	1,471.6	85.5%
North Carolina	2,475.6	425.1	582.4%	0.0	0.0	
Ohio	3,687.8	7,626.7	48.4%	0.2	0.0	
Pennsylvania	6,167.6	9,168.6	67.3%	7,505.5	11,460.8	65.5%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	5,462.0	22,772.5	24.0%	4,685.4	0.0	
Washington, D.C.	0.0	2,249.7	0.0%	0.0	0.0	
West Virginia	1,987.7	0.0		460.1	0.0	
Total	37,511.5	85,904.0	43.7%	14,313.7	14,131.3	101.3%

On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators, based on the effective load carrying capability (ELCC) method.[205] The MMU opposed the ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented data, among other issues, but does not oppose the ELCC approach in concept and when done correctly.[206] [207]

Under the pre ELCC rules a generator's capacity value was derated from the installed capacity level by multiplying the generator's net maximum capability by a derating factor. The derating factor was either based on the generator's historical performance during summer peak hours or a class average value calculated by PJM. The intent of the pre ELCC method was to obtain a MW value the generator can reliably produce during the summer peak hours.[208] As of September 30, 2022, the derated capacity with capacity obligations in the PJM Capacity Market totaled 1,563.8 MW for wind generators and 2,665.6.0 MW for solar generators. This compares to installed wind capacity of 10,995.8 MW and installed solar capacity of 5,482.6 MW in Table 8-22. PJM posts class average capacity factors for wind and solar generators. There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.[209] The ELCC rating for onshore wind capacity resources for the 2023/2024 Delivery Year is 15.0 percent.

205 See 176 FERC ¶ 61,056.
206 *In Docket ER21-278-000, see* Comments and Motions of the Independent Market Monitor for PJM, (November 20, 2020); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (December 18, 2020); Comments and Motions of the Independent Market Monitor for PJM (March 22, 2021); Answer and motion for Leave to Answer of the Independent Market Monitor for PJM (April 29, 2021)
207 *In Docket ER21-2043, see* Comments of the Independent Market Monitor for PJM (June 22, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 9, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 20, 2021);
208 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
209 See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017 <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

Table 8-22 Renewable capacity by jurisdiction (MW): September 30, 2022

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / Landfill Gas	Other Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Delaware	0.0	0.0	0.0	8.1	1,797.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	0.0	0.0	31.2	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	4,726.1	4,766.3
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	301.2	0.0	0.0	0.0	2,350.5	2,663.0
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.7
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	69.0	0.0	0.0	382.2	128.2	0.0	0.0	243.7	843.0
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	30.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	33.9	0.0	0.0	0.0	0.0	453.0	717.2	204.6	0.0	0.0	4.5	1,424.0
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	1,331.6	0.0	0.0	0.0	208.0	1,864.6
Ohio	0.0	2,320.0	194.4	58.2	0.0	1.0	136.0	0.0	0.0	445.9	0.0	0.0	134.0	1,045.6	4,335.1
Pennsylvania	54.0	0.0	1,387.3	125.2	1,300.0	0.0	0.0	0.0	1,269.0	121.8	209.3	1,347.0	0.0	1,457.2	7,270.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	241.9	585.0	436.4	127.7	0.0	88.0	17.0	0.0	5,386.0	2,140.1	123.0	0.0	0.0	12.0	9,157.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	29.1	0.0	96.0	0.0	802.3	1,145.2
PJM Total	295.9	2,905.0	2,718.7	427.3	3,097.0	89.0	222.0	13.0	7,108.0	5,482.6	665.0	1,443.0	134.0	10,995.8	35,596.3

There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[210] For the 2023/2024 Delivery Year, the ELCC rating for solar generators with fixed panels is 38.0 percent and the ELCC rating for solar generators with tracking panels is 54.0 percent.

Table 8-23 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[211] These resources are not PJM resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 9,000.9 MW of which 3,090.9 MW are in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are 1,774.7 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 54.0 MW of capacity registered with GATS located in Alabama.

210 Id.

211 PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

Table 8-23 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): September 30, 2022[212]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas / Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	142.3	0.0	0.0	0.0	2.0	146.5
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.0	20.0	55.4	0.0	2.4	983.4	0.0	0.0	0.0	398.4	1,459.6
Indiana	0.0	0.0	0.0	0.0	0.0	47.2	0.0	1.3	165.9	0.0	0.0	94.6	180.0	488.9
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	336.8	340.5
Kentucky	93.0	600.0	0.0	0.0	164.8	20.2	0.0	0.4	39.2	0.0	0.0	0.0	0.0	917.7
Maryland	3.8	65.0	0.0	20.0	0.4	13.7	0.0	0.0	1,294.4	10.0	0.0	0.0	0.3	1,407.6
Michigan	31.0	0.0	0.0	0.0	17.2	16.6	0.0	4.8	112.9	0.0	0.0	0.0	87.4	269.9
Minnesota	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	0.0	0.0	0.0	23.5	0.0	15.4	3,090.9	0.0	0.0	0.0	4.7	3,134.5
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.4
North Carolina	151.5	0.0	0.0	0.0	800.4	0.0	0.0	0.0	1,262.2	0.0	0.0	0.0	0.0	2,214.1
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	92.8	0.0	0.0	0.0	6.6	19.7	0.0	59.3	288.2	0.0	0.0	34.0	54.7	555.3
Pennsylvania	62.2	109.7	0.8	0.0	56.5	45.2	21.1	100.0	604.0	0.2	294.2	57.6	3.2	1,354.7
South Carolina	0.0	0.0	0.0	0.0	0.0	29.8	0.0	0.0	91.3	0.0	0.0	0.0	0.0	121.1
Tennessee	0.0	0.0	0.0	0.0	411.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	411.6
Virginia	287.6	0.0	0.0	0.0	31.3	9.9	0.0	2.6	527.7	0.0	0.0	0.0	0.0	859.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	176.4	0.0	0.0	13.5	0.0	239.4
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	5.8	0.0	0.0	0.0	0.0	107.8
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	44.7
Total	820.5	774.7	0.8	20.0	1,646.8	317.7	21.1	235.5	9,000.9	10.2	294.2	199.7	2,120.5	15,462.6

Renewable energy credits are related to the production and purchase of wholesale power, but have not, when they constitute a transaction separate from a wholesale sale of power, been found subject to FERC regulation.[213] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[214] This is equivalent to providing a REC price equal to three times its stated value per MWh.

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina

212 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed July 20, 2022).

213 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

214 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-24 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

Table 8-24 REC tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-25 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with each state's standards to be generated by in-state resources. Illinois recently relaxed the geographic restrictions to allow RECs sourced from wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard to be sourced from resources located in Pennsylvania.

Pennsylvania and Virginia require that RECs used for RPS compliance be produced from resources located within the PJM footprint. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

Table 8-25 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently $228.00 per MWh.[215] Pennsylvania requires that solar ACPs be 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates. The most recent ACP for Pennsylvania solar is $82.90.[216] Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[217] Maryland reduced the solar ACP from $100 per credit to $80 per credit effective June 1, 2021.[218]

Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-26 shows the alternative compliance standards for RPS in PJM jurisdictions.

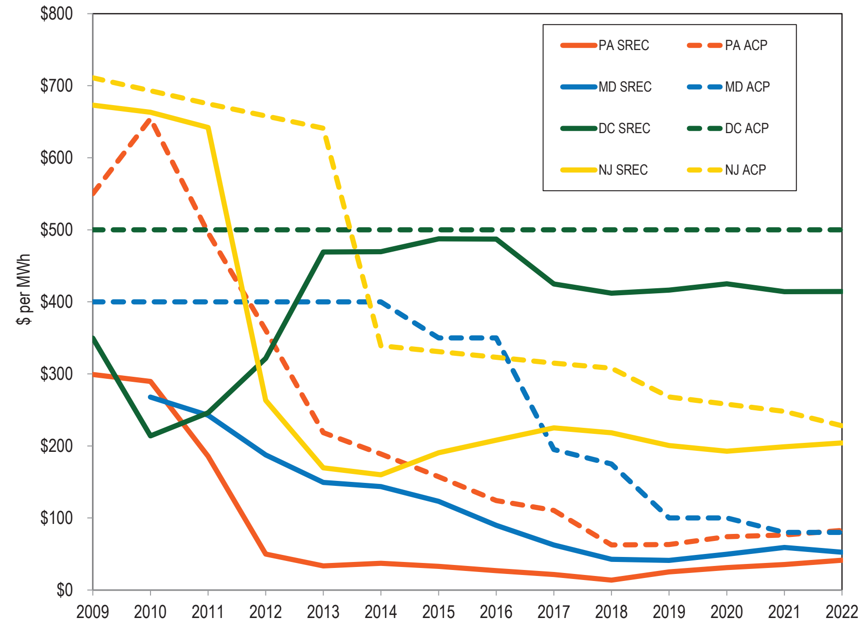
215 N.J. S. 2314/A. 3723.
216 See AEPS History Pricing report at the AEPS website <https://pennaeps.com/reports/> (Accessed October 20, 2022).
217 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
218 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

Table 8-26 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions as of September 30, 2022[219] [220]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$150.00
Illinois	$0.35		
Maryland	$30.00	$15.00	$80.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$228.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$54.14		
Pennsylvania	$45.00	$45.00	$82.90
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through September 2022



In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public.

The Pennsylvania Public Utility Commission issued their 2021 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in March of 2022.[221] Pennsylvania reported that the 681,081 SRECs, 10,615,925 Tier I RECs and 13,601,009 Tier II RECs were retired during the 2021 reporting year (June 1, 2020 through May 31, 2021). Supplier obligations for 2,572

219 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2018 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

220 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2021. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed April 1, 2021).

221 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2021," (March 2022), <https://www.puc.pa.gov/media/1843/aeps_march-2022.pdf>.

SRECs, 51,854 Tier I RECs and 66,444 Tier II RECs were resolved through ACPs.

The Public Service Commission of the District of Columbia reported that 183,707 SRECs and 2,173,550 Tier I RECs were retired during the 2021 compliance year. The average price for solar RECs was $430.94. ACPs decreased from $8.2 million for 2020 to $5.7 million for 2021.[222]

The Public Service Commission of Maryland reported that 1,859,976 SRECs were retired in 2020, an increase of 59.3 percent over the 2019 level. Tier 1 REC retirements increased to 12,117,585, 18.7 percent higher than in 2019. The RPS requirement for solar increased to 6.0 percent in 2020, up from 5.5 percent in 2019. The Tier 1 requirement increased 4.9 percentage points to 20.7 percent in 2020.[223] ACPs were $22,170 for 2020.[224]

The Public Utilities Commission of Ohio reported that 6,023,768 RECs were retired in the 2020 compliance year, which is 4,000 RECs short of the RPS requirement. Alternative compliance payments were made due to the shortfall.[225]

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 740,604 credits for the compliance year ending May 31, 2021, with zero ACPs.[226] Delmarva Power satisfied their solar REC obligation of 150,262 credits with zero alternative compliance payments.

Prior to the 2017/2018 Delivery Year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through ACPs. This requirement was removed for 2017/2018 Delivery Year and ACPs for ComEd decreased to $74,148. The 2016-2017 ACPs for ComEd totaled $40,575,311.[227]

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2018 compliance report on August 13, 2019. The compliance report stated that Dominion met its general RPS requirement by purchasing 397,643 credits that consisted of wind and hydro RECs and energy efficiency credits (EECs).[228] Dominion also met its solar, poultry waste, and swine waste requirements by purchasing RECs.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2018 standard by generating or acquiring 283,473 RECs.[229]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2021.[230] Electric power suppliers retired 11,638,713 class I RECs and 1,803,748 class II RECs. Suppliers submitted 1,892 class I ACPs and 986 class II ACPs at a cost of $50 per MWh. Electric power suppliers retired 3,851,012 solar RECs and 12 SACPs were submitted at a cost of $248 per MWh. Additionally, 128,356 transition RECs were retired.[231]

Table 8-27 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[232] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost of complying with RPS, as reported by the states, was $7.2 billion over the seven year period from 2014 through 2020 for the nine jurisdictions that had RPS and reported compliance costs.[233] The average RPS compliance cost per year

222 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2021," Public Service Commission of the District of Columbia (May 2, 2022), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
223 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2020," Public Service Commission of Maryland (November 2021) at 8, <https://www.psc.state.md.us/commission-reports/>.
224 *Id.*
225 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio (November 2, 2021), <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
226 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2020–May 31, 2021," Delmarva Power, (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>
227 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.
228 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2019) at 38, <https://www.ncuc.net/Reps/reps.html>.
229 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 18, 2020), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.
230 See RPS Report Summary 2005-2021, New Jersey's Clean Energy Program (May 17, 2022), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
231 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.
232 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.
233 The actual PJM RPS compliance cost exceeds the reported $7.2 billion due to incomplete data. The compliance cost value for 2020 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

based on the reported compliance cost for the seven year period from 2014 through 2019 was $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.

Table 8-27 RPS Compliance Cost[234 235 236 237 238 239 240 241 242 243 244]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476	$21,133,971
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914	$9,096,298
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562	$12,037,673
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523		
Maryland	Total RPS	$103,990,914	$126,727,632	$135,198,524	$72,009,070	$84,806,928	$134,545,520	$223,166,704
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	$27,351,388	$55,166,116	$122,943,987
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	$56,406,247	$79,320,505	$99,836,127
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	$1,049,293	$58,899	$386,590
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	$3,264,504		
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457	$763,108,366	$960,423,760
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153	$812,493,029
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028	$130,272,633
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185	$17,658,099
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579		
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523	$69,812,721	$81,752,397
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,234,672	$81,752,397
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066	$182,995,718
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103	$24,764,538
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310	$100,528,434
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653	$57,702,746
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701	$57,300,000	$65,000,000
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261	$51,982,914	$59,897,169
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857	$5,262,354	$5,102,831
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583	$54,733	$0
PJM	Total RPS	$678,387,871	$888,389,738	$986,186,949	$925,417,144	$986,947,843	$1,156,859,148	$1,534,472,550

234 Several states have not released compliance reports for 2020.
235 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
236 "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the ComEd cost of RECs as given in Section 11, Table 2.
237 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Nov. 2021) at 8, <https://www.psc.state.md.us/commission-reports/>.
238 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 18, 2020, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
239 "RPS Report Summary 2005-2020," New Jersey's Clean Energy Program, April 13, 2021, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
240 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio, Nov. 2, 2021, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
241 "2020 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, February 2021 <https://www.puc.pa.gov/media/1410/aeps-annreport2020.pdf>.
242 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2020," Public Service Commission of the District of Columbia, Executive Summary, May 3, 2021, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
243 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.
244 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[245] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[246] [247]

Table 8-28 shows SO_2 emission controls by fossil fuel fired units in PJM.[248] [249] [250] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[251] Of the current 51,722.2 MW of coal capacity in PJM, 49,660.0 MW of capacity, 96.0 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-28 SO_2 emission controls by fuel type (MW): September 30, 2022[252]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	49,660.0	2,062.2	51,722.2	96.0%
Diesel Oil	0.0	4,606.4	4,606.4	0.0%
Natural Gas	0.0	67,784.6	67,784.6	0.0%
Other	325.0	3,500.0	3,825.0	8.5%
Total	49,985.0	77,953.2	127,938.2	39.1%

Table 8-29 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 51,722.2 MW of coal capacity in PJM, 51,636.2 MW of capacity, 99.8 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[253]

Table 8-29 NO_X emission controls by fuel type (MW): As of September 30, 2022

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	51,636.2	86.0	51,722.2	99.8%
Diesel Oil	1,020.3	3,586.1	4,606.4	22.1%
Natural Gas	67,541.6	243.0	67,784.6	99.6%
Other	1,575.0	2,250.0	3,825.0	41.2%
Total	121,773.1	6,165.1	127,938.2	95.2%

Table 8-30 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8 percent) in PJM have particulate controls, as well as a few natural gas units (4.3 percent) and units with other fuel sources (51.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[254] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 51,722.2 MW of coal capacity in PJM, 51,637.2 MW of capacity, 99.8 percent, have some type of particulate emissions control technology. In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR. Currently, all of the 109 coal steam units have baghouse or FGD technology installed for either SO_2 or particulate emissions control, representing all of the 51,722.2 MW total coal capacity, or 100.0 percent.

245 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
246 On April 16, 2020, the EPA issued a revised final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed May 7, 2020).
247 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards," <https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)
248 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
249 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year. The most recent complete set of emissions data is from 2021.
250 The total MW are less than the 181,345.8 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed March 4, 2022).
251 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).
252 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.
253 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
254 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 4, 2022).

Table 8-30 Particulate emission controls by fuel type (MW): As of September 30, 2022

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	51,637.2	85.0	51,722.2	99.8%
Diesel Oil	0.0	4,606.4	4,606.4	0.0%
Natural Gas	2,912.0	64,872.6	67,784.6	4.3%
Other	1,972.0	1,853.0	3,825.0	51.6%
Total	56,521.2	71,417.0	127,938.2	44.2%

Emissions

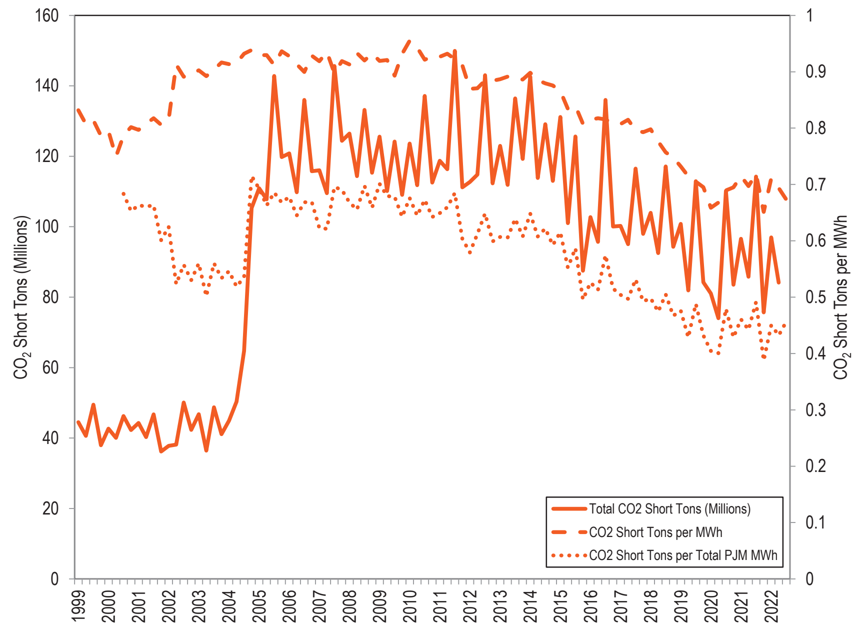
Figure 8-10 shows the total CO_2 emissions in short tons, the CO_2 emission rate in short tons per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the third quarter of 2022, and the CO_2 emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the third quarter of 2022.[255] [256]

Figure 8-11 shows the total CO_2 emission in short tons on peak and off peak and the CO_2 emission rate in short tons per MWh for all CO_2 emitting units.

Table 8-31 shows the minimum and maximum CO_2 emission rates in short tons per MWh for all CO_2 emitting units, for all hours, as well as on and off peak hours, from the third quarter of 1999 through the third quarter of 2022.

Total PJM generation decreased from 232,549.2 GWh in the third quarter of 2021 to 231,937.8 GWh in the third quarter of 2022, while CO_2 produced decreased from 114.2 million short tons in the third quarter of 2021 to 105.8 million short tons in the third quarter of 2022.[257] The CO_2 emission rate averaged 0.67 short tons per MWh for all CO_2 emitting units in the first nine months of 2020, 0.71 short tons per MWh for all CO_2 emitting units in the first nine months of 2021, and 0.69 short tons per MWh for all CO_2 emitting units in the first nine months of 2022.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through September 2022[258] [259]



In the third quarter of 2022, CO_2 emission rates were 0.67 short tons per MWh for all CO_2 emitting units for off peak hours, and 0.67 for on peak hours. Of the top 10 largest CO_2 emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.[260]

255 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
256 Emissions data for the third quarter of 2022 was not yet finalized at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.
257 See the *2021 Annual State of the Market Report for PJM:* Section 3: Energy Market, Table 3-10.
258 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
259 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).
260 "The top 10 emitting power plants in America," < https://www.eenews.net/articles/the-top-10-emitting-power-plants-in-america/> (Accessed November 4, 2022).

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: January 1999 through September 2022[261]

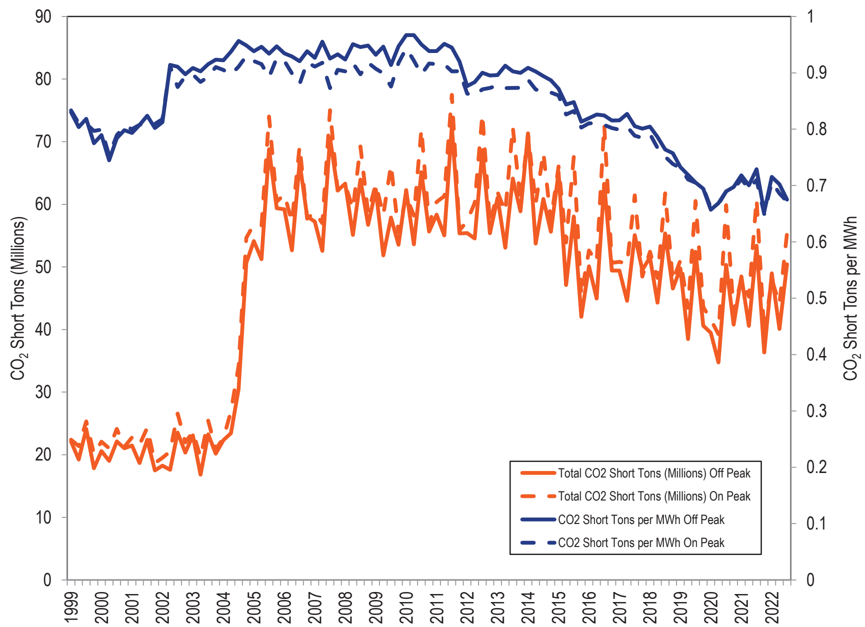


Table 8-31 Minimum and maximum CO_2 emissions per MWh: September 1999 through September 2022

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.65	2021	4
	On Peak	0.65	2021	4
	Off Peak	0.65	2021	4
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

Figure 8-12 shows the total SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emission rate in short tons per MWh of total PJM generation. In the third quarter of 2022, the SO_2 emission rate was 0.000361 short tons per MWh for all SO_2 emitting units, and the NO_X emission rate was 0.000190 short tons per MWh for all NO_X emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units. In the third quarter of 2022, SO_2 emission rates were 0.000363 short tons per MWh and 0.000359 short tons per MWh for all SO_2 units, for off and on peak hours. In the second quarter of 2022, NO_X emission rates were 0.000182 short tons per MWh and 0.000197 short tons per MWh for all NO_X emitting units, for off and on peak hours.

Table 8-32 shows the minimum and maximum SO_2 and NO_X emission rate in short tons per MWh for all SO_2 and NO_X emitting units, for all hours, as well as on and off peak hours, from the third quarter of 1999 through the third quarter of 2022.

In the third quarter of 2022, the SO_2 emission rate was 0.000420 short tons per MWh for all SO_2 emitting units, and the NO_X emission rate was 0.000233 short tons per MWh for all NO_X emitting units. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2022.[262] [263] There has been an increase in the SO_2 emissions since 2020, as a result of an increase in coal usage within PJM. The SO_2 emission rate averaged 0.000383 short tons per MWh for all SO_2 emitting units in the first nine months of 2020, 0.000443 short tons per MWh for all SO_2 emitting units in the first nine months of 2021, and 0.000410 short tons per MWh for all SO_2 emitting units in the first nine months of 2022. Despite the increase in coal usage since 2020, the NO_X emission rate is lower having been offset by installation of additional environmental controls (See Table 8-29). The NO_X emission rate averaged 0.000295 short tons per MWh for all NO_X emitting units in the first nine months of 2020, 0.000284 short tons per MWh for all NO_X emitting units in the first nine months of 2021,

261 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

262 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

263 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

and 0.000255 short tons per MWh for all NO_X emitting units in the first nine months of 2022.

Figure 8-12 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: January 1999 through September 2022[264]

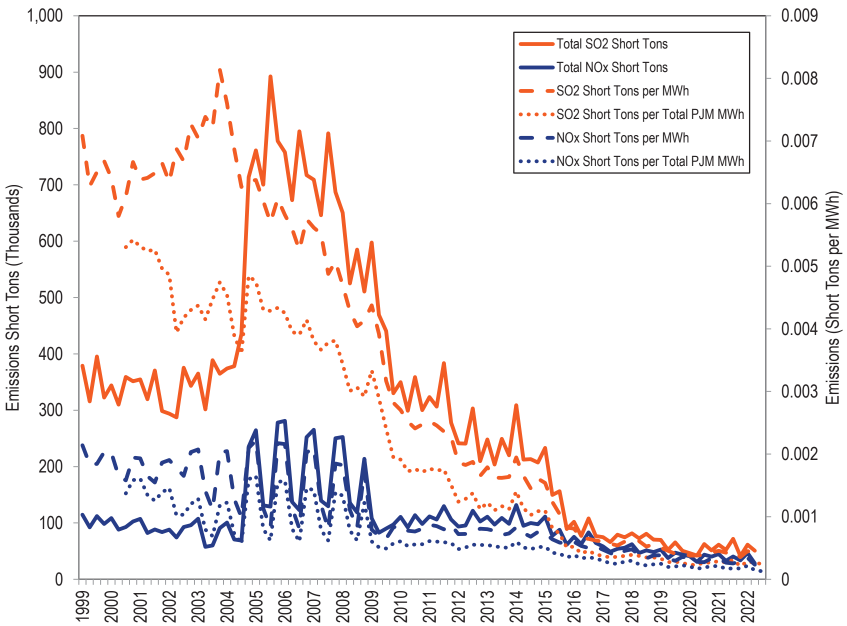
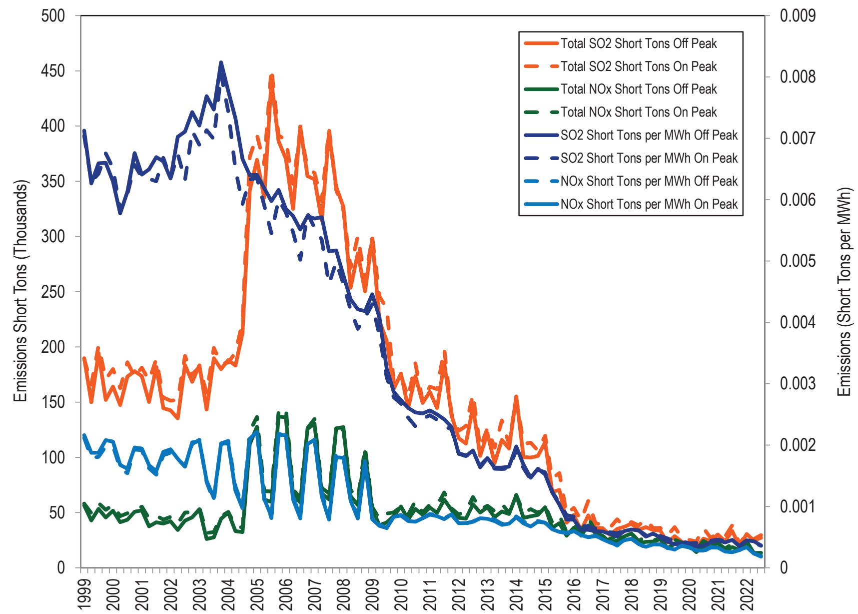


Figure 8-13 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through September 2022[265]



264 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

265 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Table 8-32 Minimum and maximum SO_2 and NO_x emissions per MWh: September 1999 through September 2022

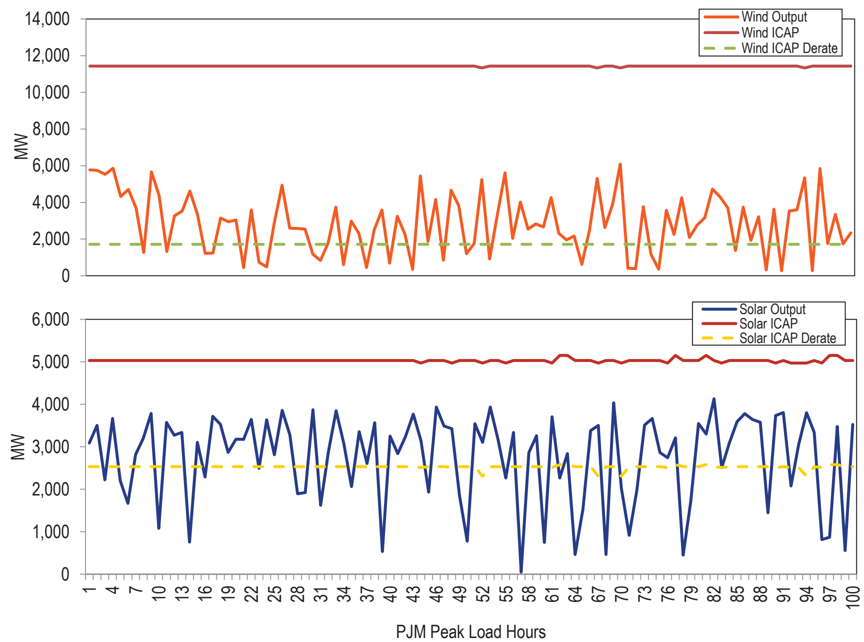
Emission Type			Short Tons per MWh	Year	Quarter
SO_2	Minimum	All hours	0.000	2021	4
		On Peak	0.000	2022	3
		Off Peak	0.000	2021	4
	Maximum	All hours	0.008	2003	4
		On Peak	0.008	2003	4
		Off Peak	0.008	2003	4
NO_x	Minimum	All hours	0.000	2022	3
		On Peak	0.000	2022	3
		Off Peak	0.000	2022	3
	Maximum	All hours	0.002	2005	1
		On Peak	0.002	2005	1
		Off Peak	0.002	2005	1

Renewable Energy Output

Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated from the nameplate or installed capacity value to a level intended to reflect that the resources are a substitute for other capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during high load hours and are based on actual historical performance. Figure 8-14 shows the wind and solar output during the top 100 load hours in PJM in the first nine months of 2022. In the first nine months of 2022, 95 of the top 100 load hours in PJM are PJM defined peak load hours. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market.[266] The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity values. Wind output was above the derated ICAP for 75 hours and below the derated ICAP for 25 hours of the top 100 load hours in the first nine months of 2022. The wind capacity factor for the top 100 load hours in the first nine months of 2022 was 25.0 percent. Wind output was above the derated ICAP for 4,210 hours and below the derated ICAP for 2,341 hours in the first nine months of 2022. The wind capacity factor in the first nine months of 2022 was 29.3 percent. Solar output was above the derated ICAP for 67 hours and below the derated ICAP for 33 hours of the top 100 load hours in the first nine months of 2022. The solar capacity factor for the top 100 load hours in the first nine months of 2022 was 54.9 percent. Solar output was above the derated ICAP for 1,687 hours and below the derated ICAP for 4,864 hours in the first nine months of 2022. The solar capacity factor in the first nine months of 2022 was 23.3 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through September 2022



266 See Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (AccessedOctober 20, 2022).

Wind Units

Table 8-33 shows the capacity factors of wind units in PJM. In the first nine months of 2022, the capacity factor of wind units in PJM was percent. Wind units that were capacity resources had a capacity factor of 29.9 percent and an installed capacity of 9,988.9 MW. Wind units that were energy only had a capacity factor of 25.0 percent and an installed capacity of 1,387.4 MW. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.[267]

Table 8-33 Capacity factor of wind units: January through September, 2022[268]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	25.0%	1,387.4
Capacity Resource	29.9%	9,988.9
All Units	29.3%	11,376.3

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for the first nine months of 2022. The hour with the highest average output in the first nine months of 2022, 5,375.9 MWh, occurred in February, and the hour with the lowest average output, 1,091.4 MWh, occurred in August. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-15 Average hourly real-time generation of wind units: January through September, 2022

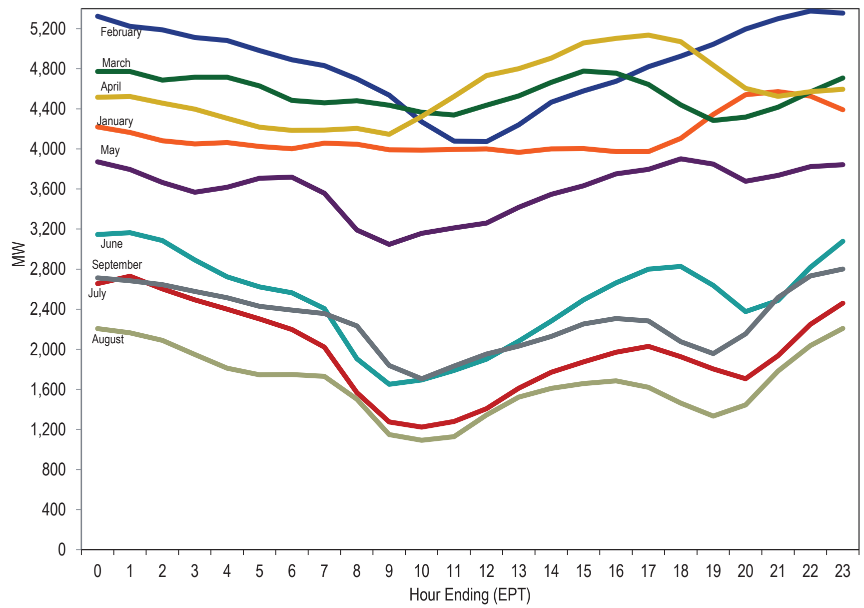


Table 8-34 shows the generation and capacity factor of wind units by month for the first nine months of 2021 and 2022.

Table 8-34 Capacity factor of wind units in PJM by month: January through September, 2021 and 2022

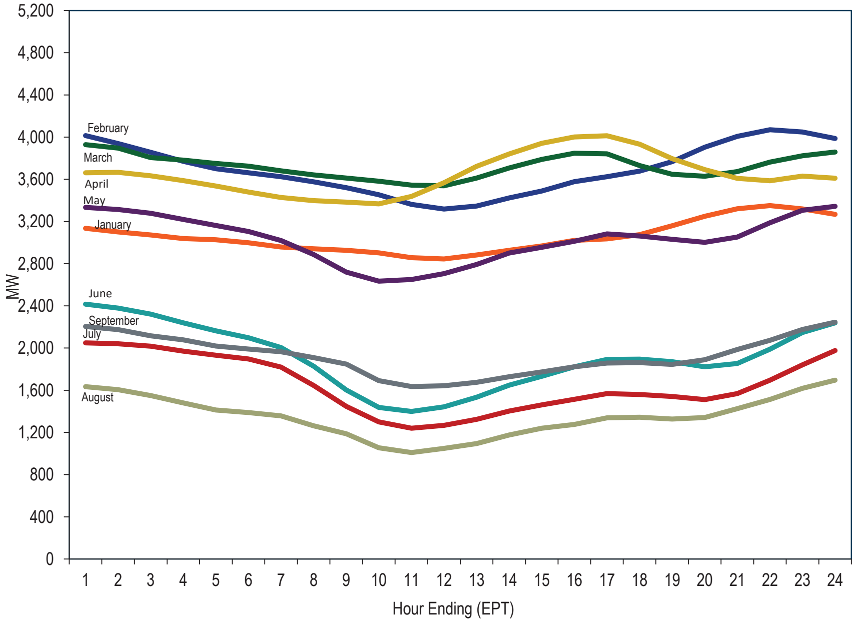
	2021		2022	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,486,737.9	30.5%	3,072,620.3	36.4%
February	2,595,370.6	34.7%	3,256,337.2	42.8%
March	3,399,080.7	41.1%	3,386,619.2	40.2%
April	2,684,454.5	33.5%	3,298,156.9	40.4%
May	2,110,377.3	25.5%	2,676,674.3	31.7%
June	1,691,536.1	21.1%	1,803,398.8	21.9%
July	1,073,252.3	13.0%	1,473,973.6	17.3%
August	1,087,078.7	13.1%	1,242,872.1	14.6%
September	2,137,750.7	26.7%	1,655,008.7	20.1%

267 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 20, 2022).

268 Capacity factor is calculated based on online date of the resource.

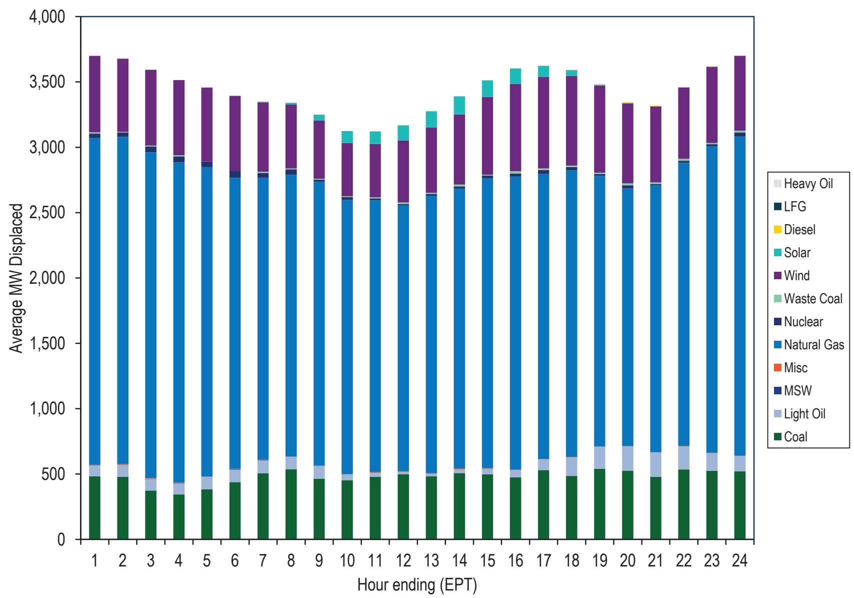
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-16 Average hourly day-ahead generation of wind units: January through September, 2022



Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output.[269] Figure 8-17 and Table 8-35 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2022. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first nine months of 2022, the SCED dispatch instruction for marginal wind resources was to reduce output for 69.8 percent of the wind unit intervals. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

Figure 8-17 Marginal fuel at time of wind generation: January through September, 2022



269 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Table 8-35 Marginal fuel MW at time of wind generation: January through September, 2022

Hour	Coal	Light Oil	MSW	Misc	Natural Gas	Nuclear	Waste Coal	Wind	Solar	Diesel	LFG	Heavy Oil	Total
0	481.4	84.3	0.6	4.7	2,499.3	34.3	9.7	585.2	0.0	0.0	0.0	0.0	3,699.5
1	478.3	89.8	0.0	8.1	2,505.3	31.4	5.5	559.0	0.7	0.0	0.0	0.0	3,678.1
2	373.7	87.8	1.8	5.4	2,493.0	45.0	6.4	579.5	1.0	0.0	0.0	0.0	3,593.7
3	343.6	83.0	3.4	3.1	2,450.8	46.5	9.6	573.9	0.0	0.0	0.0	0.0	3,513.9
4	384.0	94.9	1.0	1.3	2,366.9	42.0	1.4	565.6	0.0	0.3	0.0	0.0	3,457.3
5	437.9	97.5	5.8	1.2	2,223.9	55.1	0.0	570.7	2.1	0.0	0.0	0.0	3,394.2
6	506.0	97.7	3.4	2.8	2,157.1	36.0	9.9	531.3	2.6	0.3	1.2	0.0	3,348.5
7	537.3	95.3	1.1	0.0	2,155.8	41.3	6.9	488.4	11.5	0.3	1.4	0.0	3,339.2
8	464.7	96.5	2.0	1.8	2,170.8	16.2	6.3	446.3	43.4	0.4	1.2	0.0	3,249.6
9	453.3	43.7	1.3	1.4	2,098.5	19.9	7.6	407.6	89.6	0.0	1.1	0.3	3,124.2
10	478.0	31.4	0.7	6.7	2,077.6	14.5	8.4	407.2	96.9	0.0	0.0	0.0	3,121.4
11	498.8	17.2	0.0	4.6	2,036.2	9.8	11.0	474.8	114.3	0.0	0.3	1.3	3,168.3
12	482.0	21.9	0.3	2.4	2,123.6	13.5	8.1	500.8	122.9	0.6	0.0	0.0	3,276.2
13	507.3	28.9	0.4	6.5	2,141.1	17.5	13.0	537.2	137.1	0.0	0.6	0.5	3,389.9
14	497.9	41.1	0.0	6.2	2,218.4	19.4	7.3	595.4	127.6	0.3	0.0	1.1	3,514.7
15	474.9	53.8	1.8	3.6	2,241.7	23.0	18.6	667.6	118.1	0.8	0.0	0.6	3,604.5
16	530.8	81.9	1.4	0.9	2,180.5	30.5	11.7	701.3	81.7	2.1	0.7	1.6	3,625.1
17	485.0	143.5	0.2	3.0	2,191.1	26.2	10.6	687.1	40.2	2.5	1.7	4.0	3,595.1
18	539.2	170.2	0.1	2.1	2,069.3	16.3	8.4	666.2	5.6	1.8	0.2	0.3	3,479.6
19	525.7	185.2	1.8	1.8	1,970.6	24.0	15.1	610.2	4.0	6.8	0.0	0.0	3,345.2
20	478.2	188.0	0.6	0.6	2,042.8	9.1	12.1	581.8	0.1	6.7	0.0	0.0	3,319.9
21	535.4	176.6	0.5	3.5	2,164.6	16.4	15.1	546.0	0.2	0.0	0.0	0.7	3,459.2
22	524.8	136.4	0.2	0.8	2,346.6	14.4	9.8	582.4	0.4	1.5	0.3	0.7	3,618.3
23	521.0	117.2	0.0	1.9	2,442.5	30.0	14.2	571.6	0.5	0.8	0.9	0.0	3,700.7
Average	480.8	94.3	1.2	3.1	2,223.7	26.3	9.5	559.9	41.7	1.0	0.4	0.5	3,442.3

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all PJM solar units that are in front of the meter. As shown in Table 8-22, there are 5,482.6 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-23, there are 9,000.9 MW capacity of solar registered in GATS that are not PJM units. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to avoid their proper financial responsibility through badly designed rules, such as rules for netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-36 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 23.3 percent in the first nine months of 2022. Solar units that were capacity resources had a capacity factor of 23.2 percent and an installed capacity of 3,703.7 MW. Solar units that were energy only had a capacity factor of 23.8 percent and an installed capacity of 1,276.6 MW. Solar capacity in RPM is derated to 38.0, 42.0 or 60.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.[270]

Table 8-36 Capacity factor of solar units: January through September, 2022

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	23.8%	1,276.6
Capacity Resource	23.2%	3,703.7
All Units	23.3%	4,980.3

Figure 8-18 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output in the first nine months of 2022, 3,591.9 MW, occurred in June, and the hour with the lowest peak average output, 1,970.5 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

270 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed July 24, 2019).

Figure 8-18 Average hourly real-time generation of solar units: January through September, 2022

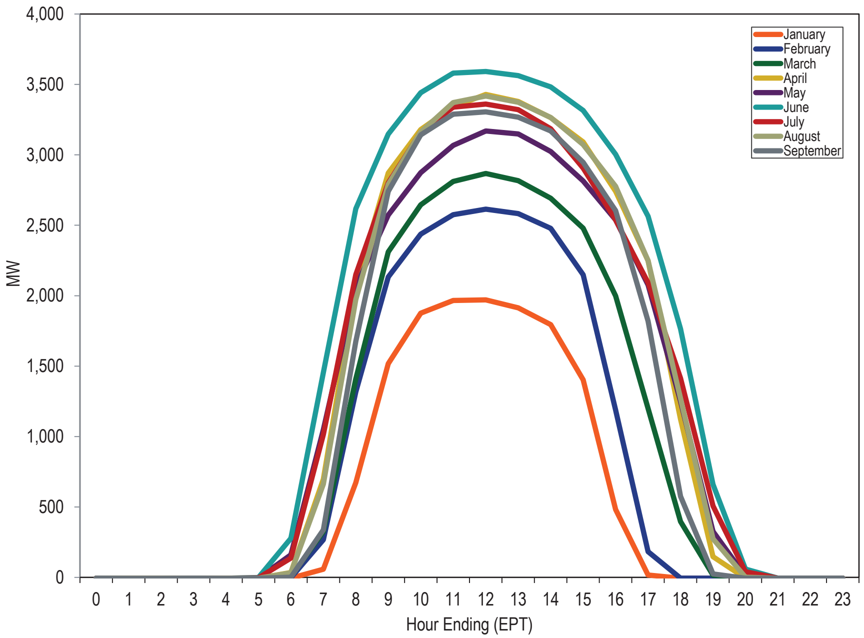


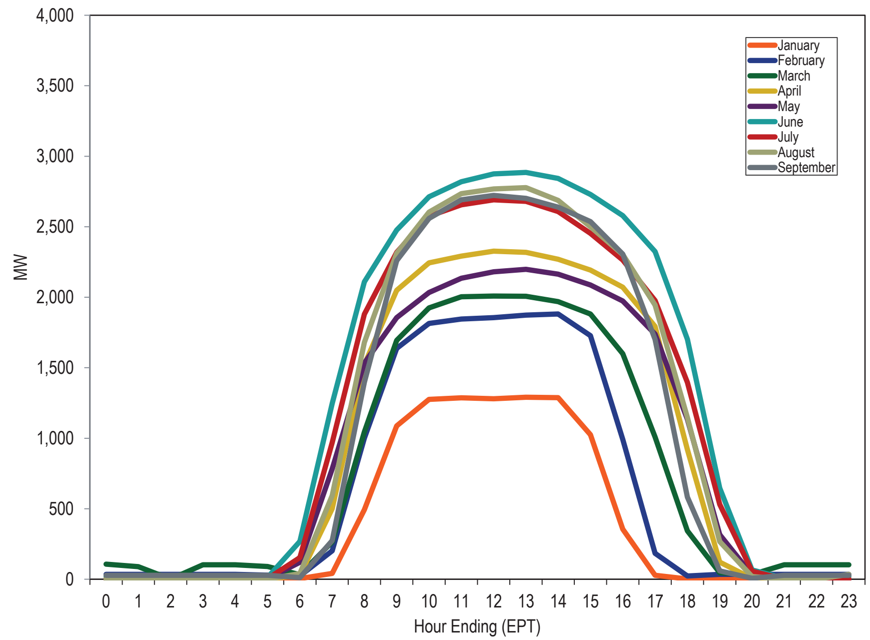
Table 8-37 shows the generation and capacity factor of solar units by month for the first nine months of 2021 and 2022.

Table 8-37 Capacity factor of solar units by month: January through September, 2021 and 2022

	2021		2022	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	303,578.0	10.6%	426,957.6	11.8%
February	279,267.0	10.4%	564,995.2	17.2%
March	578,735.6	19.4%	754,200.7	20.7%
April	711,376.4	23.8%	956,146.4	26.8%
May	814,711.9	26.1%	945,079.2	25.6%
June	809,575.7	26.8%	1,103,443.9	30.8%
July	874,340.0	28.0%	998,652.5	26.7%
August	789,824.1	25.2%	989,813.8	26.1%
September	751,990.4	24.1%	877,827.2	23.7%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[271]

Figure 8-19 Average hourly day-ahead generation of solar units: January through September, 2022



Output from solar generators displaces output from other generation types because, in general, solar photovoltaic cells generate power when the sun is shining, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of solar generation output, its location, time and duration. One measure of this displacement is based on the mix of marginal

271 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

units when a solar unit is producing output.[272] Figure 8-20 and Table 8-38 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time solar generation in the first nine months of 2022. This is not an exact measure of displacement because it is not based on a redispatch of the system without solar resources. In the first nine months of 2022, the SCED dispatch instruction for marginal solar resources was to reduce output for 80.8 percent of the solar unit intervals. When solar appears as the displaced fuel at times when solar resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of solar displaced by solar is thus overstated.

Figure 8-20 Marginal fuel at time of solar generation: January through September, 2022

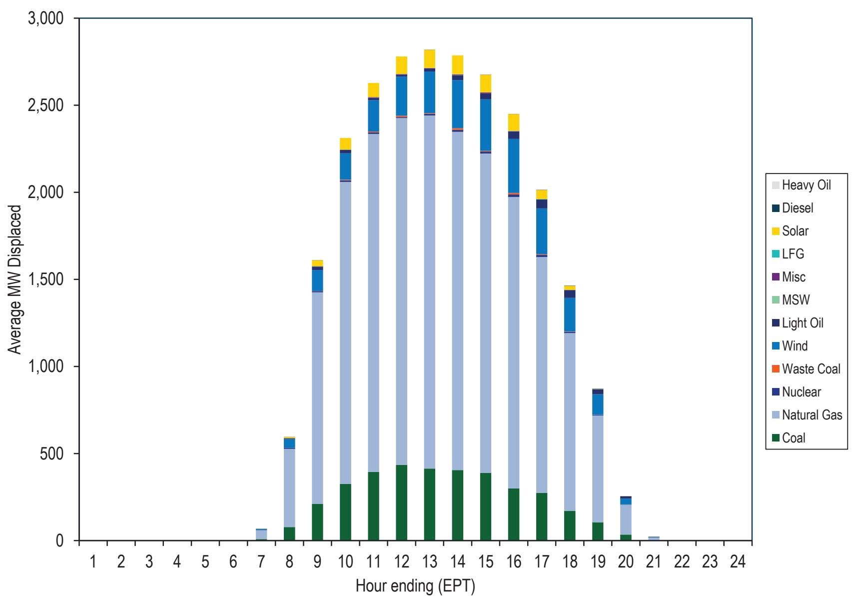


Table 8-38 Marginal fuel MW at time of solar generation: January through September, 2022

Hour	Coal	Natural Gas	Nuclear	Waste Coal	Wind	Light Oil	MSW	Misc	LFG	Solar	Diesel	Heavy Oil	Total
0	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
2	0.1	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
3	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
4	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
5	0.1	0.9	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1
6	8.1	51.3	0.6	0.2	6.3	0.1	0.3	0.1	0.0	0.4	0.0	0.0	67.5
7	77.3	448.9	6.2	0.4	48.9	5.8	0.9	0.0	0.1	5.9	0.0	0.0	594.4
8	211.1	1,214.7	6.5	1.3	119.8	20.1	0.7	1.4	0.4	33.3	0.3	0.0	1,609.7
9	325.3	1,734.5	9.0	3.8	151.4	19.9	0.3	0.6	0.1	66.5	0.0	0.5	2,311.9
10	394.4	1,941.0	8.0	5.3	180.0	13.9	0.3	3.8	0.0	81.5	0.0	0.0	2,628.2
11	434.4	1,992.2	5.5	7.3	224.5	11.2	0.0	3.9	0.7	99.9	0.0	1.3	2,780.9
12	413.5	2,028.2	8.1	4.3	239.8	18.1	0.5	1.7	0.0	105.0	0.5	0.0	2,819.7
13	404.9	1,942.0	11.2	9.6	276.9	28.5	0.5	3.8	0.6	107.9	0.0	0.7	2,786.7
14	389.3	1,833.2	11.9	4.2	295.0	34.7	0.0	5.0	0.0	102.3	0.4	1.5	2,677.6
15	299.1	1,674.4	14.1	9.3	309.5	43.5	1.3	2.2	0.0	95.5	0.9	0.5	2,450.2
16	274.2	1,354.5	11.0	4.8	263.5	50.8	0.6	0.3	1.3	52.3	1.2	0.9	2,015.2
17	169.6	1,021.6	7.7	2.5	192.6	44.2	0.4	0.8	1.2	22.4	1.4	2.2	1,466.5
18	105.1	612.8	3.5	1.5	117.3	28.8	0.0	0.1	0.3	1.6	1.6	0.1	872.5
19	33.9	172.4	1.1	0.4	32.5	13.0	0.1	0.0	0.0	0.5	1.0	0.0	254.9
20	3.0	14.9	0.0	0.0	1.9	0.6	0.0	0.0	0.0	0.0	0.1	0.0	20.6
21	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
22	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
23	0.1	0.4	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Average	147.6	751.6	4.3	2.3	102.5	13.9	0.3	1.0	0.2	32.3	0.3	0.3	1,056.7

272 The measure is based on the principle that any incremental change in the solar output is balanced by the change in the output of marginal generators, while holding everything else equal.

Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2022, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] 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.
- **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.[2]
- **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.[3]
- **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

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

2 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.

3 Id.

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.

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.)[4]
- 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.)

4 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.

- 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 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.)

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.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the real-time or day-ahead energy market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[5]

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		X
Balancing Operating Reserve	X	X	X						X
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO
2 No charge for spot in transmission

5 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (June 1, 2022) <https://pjm.com/markets-and-operations/~/media/0FE1D93C5E61457185BB7652F2F18668.ashx>.

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first nine months of 2021 and 2022. 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 gross exports in the real-time energy market (74.4 percent in the first nine months of 2021).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through September, 2021 and 2022

Category	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change
Real-Time Gross Imports	4,761.3	10,919.0	129.3%
Real-Time Gross Exports	34,265.9	37,223.3	8.6%
Real-Time Net Interchange	(29,504.6)	(26,304.3)	(10.8%)
Day-Ahead Gross Imports	6,001.4	11,948.6	99.1%
Day-Ahead Gross Exports	25,497.7	32,177.7	26.2%
Day-Ahead Net Interchange	(19,496.3)	(20,229.1)	3.8%
Monthly Average Real-Time Gross Exports	3,807.3	4,135.9	8.6%
Monthly Average Real-Time Gross Imports	529.0	1,213.2	129.3%
Monthly Average Day-Ahead Gross Exports	2,833.1	3,575.3	26.2%
Monthly Average Day-Ahead Gross Imports	666.8	1,327.6	99.1%

In the first nine months of 2022, PJM was a monthly net exporter of energy in the real-time energy market in all months. In the first nine months of 2022, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[6]

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and real-time energy markets times the applicable operating reserve rates. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020. In 2020, the total day-ahead gross imports and exports were higher than the real-time gross imports and exports, the day-ahead imports net of up to congestion transactions were less than the real-time imports, and the day-ahead exports net of up to congestion transactions were less than real-time exports.

Figure 9-1 Scheduled imports and exports: January through September, 2022

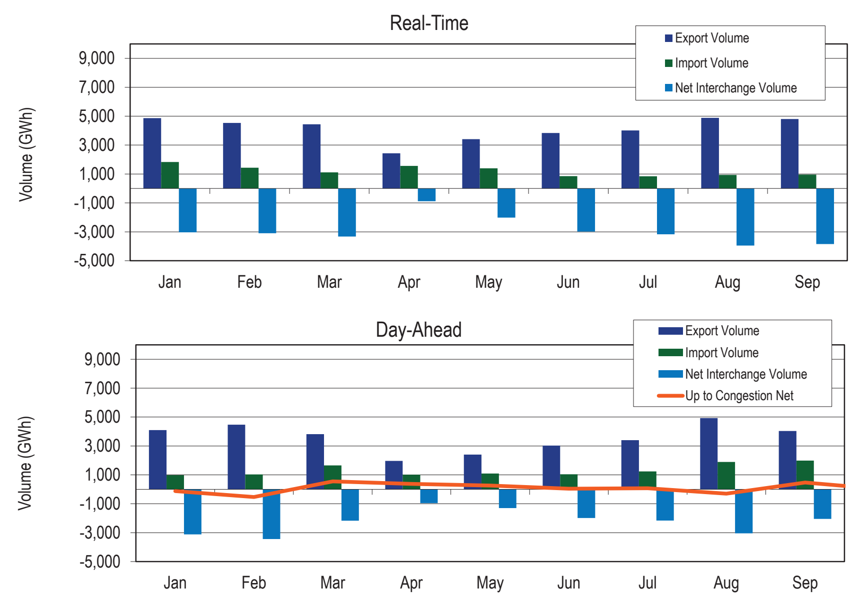


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through September 2022. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up

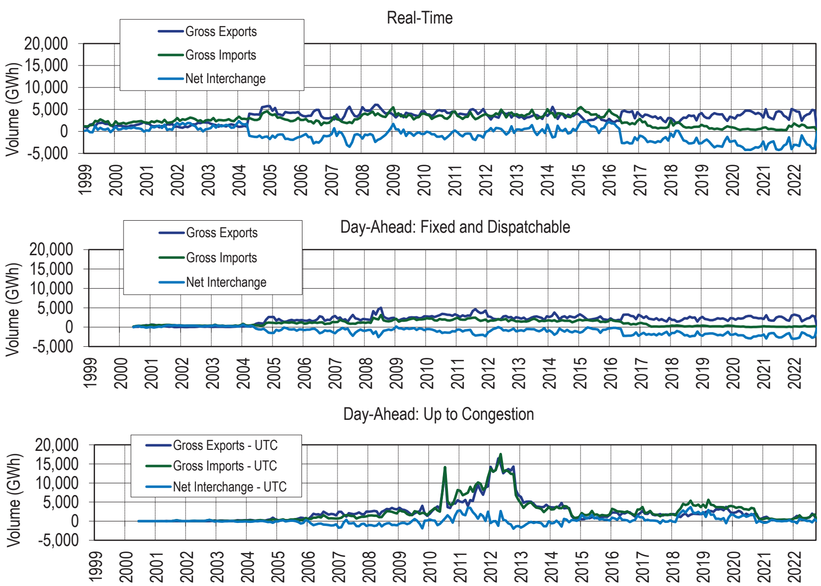
6 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the day-ahead energy market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the day-ahead energy market decreased, PJM has remained primarily a net exporter in the day-ahead energy market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the real-time and day-ahead energy markets. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[7] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[8] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased. In February 2021, winter storms caused significant generation outages in Texas and resulted in power outages across the Electric Reliability Council of Texas (ERCOT) region. These outages occurred between February 10, 2021, and February 27, 2021. During this time, ERCOT imported generation from neighboring regions. While PJM did not have any scheduled exports directly to the ERCOT region, PJM exports during this time increased from an average hourly export of 4,772 MW per hour between February 1 and February 10, 2021, to 7,003 MW per hour between February 10 and February 27, 2021.

On June 13, 2022, PJM experienced several intervals of shortage pricing that resulted in high LMPs during the period from 1450 through 1800. PJM remained a net exporter of energy throughout the period despite the fact that PJM prices were much higher than MISO prices. PJM net exports averaged 4,431 MW during hours ending 1500 through 1800, a slight decrease from average net exports of 5,560 MW during the hours ending 1100 through 1400. Market participant response to the pricing signals in this period was affected by TLRs issued by MISO, SWPP and PJM, although the curtailments of scheduled imports to PJM were relatively small compared to the net exports. Export transactions to MISO continued to flow during this period primarily on firm and grandfathered transmission service. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first nine months of 2022, flows were in the uneconomic direction on the PJM/MISO interface in 45.7 percent of all hours.

7 162 FERC ¶ 61,139.
8 172 FERC ¶ 61,046.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through September 30, 2022



Real-Time Interface Imports and Exports

In the real-time energy market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-19 includes a list of active interfaces in the first nine months of 2022. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2022, PJM had 19 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. There are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the real-time energy market is shown by interface for the first nine months of 2022 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the real-time energy market, in the first nine months of 2022, there were net scheduled exports at 15 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 44.0 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 15.2 percent, PJM/MidAmerican Energy Company (MEC) with 15.1 percent and PJM/NYIS with 13.7 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 39.0 percent of the total net PJM scheduled exports in the real-time energy market. There were net scheduled exports in the real-time energy market at eight of the 10 separate interfaces that connect PJM to MISO. Those eight exporting interfaces represented 54.7 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2022, there were net scheduled imports at three of PJM's 19 interfaces. The top importing interface in the real-time energy market was the PJM/Ameren-Illinois (AMIL) Interface, which accounted for 65.0 percent of the total net scheduled import volume.[9] The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the real-time energy market. There were net scheduled imports in the real-time energy market at one of the 10 separate interfaces that connect PJM to MISO (Ameren-Illinois (AMIL)). This importing interface represented 65.0 percent of the total net PJM scheduled imports in the real-time energy market.

9 In the real-time energy market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(62.0)	17.2	(2.2)	16.5	(56.1)	(110.3)	(106.9)	(179.0)	(77.4)	(560.2)
CPLW	0.7	0.6	0.5	1.7	0.0	0.0	(0.1)	0.1	0.0	3.5
DUK	84.3	156.9	227.3	87.4	(69.6)	(62.7)	(485.1)	(335.8)	(66.2)	(463.7)
LGEE	(76.1)	(97.2)	(71.8)	(53.1)	(38.5)	(134.1)	(107.3)	(116.6)	(103.6)	(798.2)
MISO	(969.4)	(1,218.7)	(1,896.8)	(830.3)	(1,581.0)	(1,998.2)	(1,412.3)	(1,871.1)	(2,349.8)	(14,127.4)
ALTE	(139.7)	(232.8)	(306.1)	(124.3)	(173.9)	(478.0)	(299.8)	(399.4)	(380.4)	(2,534.4)
ALTW	(9.4)	(14.0)	(29.4)	(24.0)	(28.1)	(36.8)	(25.4)	(25.1)	(40.8)	(232.9)
AMIL	385.4	355.5	100.8	339.1	227.6	134.6	187.0	135.2	(203.0)	1,662.2
CIN	(328.1)	(425.6)	(874.3)	(341.8)	(643.1)	(541.1)	(406.1)	(506.0)	(314.4)	(4,380.4)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	15.6	(5.2)	(11.4)	(30.4)	(36.4)	(36.5)	(18.3)	(13.4)	(24.0)	(160.1)
MEC	(485.4)	(401.4)	(482.3)	(341.8)	(522.1)	(517.8)	(475.4)	(519.1)	(626.7)	(4,372.0)
MECS	52.0	(207.1)	(254.7)	(305.3)	(359.2)	(425.1)	(316.0)	(480.1)	(655.3)	(2,950.7)
NIPS	(297.6)	(268.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(566.0)
WEC	(162.3)	(19.7)	(39.4)	(1.9)	(45.8)	(97.5)	(58.1)	(63.2)	(105.1)	(593.1)
NYISO	(2,307.9)	(2,244.0)	(1,766.2)	(275.6)	(397.6)	(484.6)	(870.9)	(1,485.3)	(1,416.3)	(11,248.5)
HUDS	(466.4)	(421.3)	(347.3)	(121.5)	(173.3)	(128.1)	(223.3)	(282.3)	(320.4)	(2,483.9)
LIND	(229.8)	(214.6)	(200.0)	(151.7)	(226.7)	(203.4)	(214.1)	(203.8)	(223.2)	(1,867.2)
NEPT	(282.0)	(250.3)	(282.6)	(274.2)	(282.3)	(271.8)	(326.6)	(498.7)	(483.6)	(2,952.0)
NYIS	(1,329.8)	(1,357.9)	(936.3)	271.8	284.6	118.6	(106.8)	(500.6)	(389.1)	(3,945.4)
TVA	294.6	284.9	186.8	174.0	128.1	(195.0)	(184.6)	39.4	161.8	890.2
Total	(3,035.9)	(3,100.3)	(3,322.4)	(879.4)	(2,014.6)	(2,984.9)	(3,167.1)	(3,948.3)	(3,851.4)	(26,304.3)

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	9.6	40.2	35.2	38.2	22.9	7.0	8.9	4.7	14.4	181.1
CPLW	0.7	0.6	0.5	1.7	0.0	0.0	0.0	0.2	0.0	3.7
DUK	282.8	268.5	281.0	196.6	210.6	260.2	150.0	187.3	275.7	2,112.6
LGEE	36.8	6.8	5.7	24.7	39.8	0.1	12.3	22.1	8.3	156.5
MISO	1,059.0	713.2	453.4	699.9	551.5	277.6	415.6	390.3	297.5	4,858.0
ALTE	67.7	35.8	43.3	33.7	43.6	12.0	53.7	33.4	21.8	345.1
ALTW	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.3
AMIL	481.9	379.2	169.0	364.3	325.1	168.7	188.9	165.7	161.4	2,404.2
CIN	63.5	42.3	27.9	69.1	67.2	23.7	47.0	52.5	45.5	438.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	22.5	3.6	1.0	0.0	0.2	0.9	5.6	13.4	3.9	51.1
MEC	11.7	38.0	18.9	17.5	19.6	15.3	17.5	22.1	14.0	174.5
MECS	300.5	152.9	126.7	141.6	55.8	16.0	61.7	52.2	19.0	926.4
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	111.0	61.5	66.6	73.7	39.9	41.0	41.0	50.8	32.0	517.5
NYISO	136.9	111.3	130.2	391.3	363.6	227.1	180.7	132.8	118.0	1,791.8
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LIND	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	136.9	111.2	130.1	391.2	363.6	227.0	180.6	132.7	118.0	1,791.5
TVA	306.0	292.5	209.8	204.9	208.4	76.7	73.9	202.0	241.0	1,815.3
Total	1,831.7	1,433.1	1,115.8	1,557.2	1,396.9	848.8	841.3	939.4	954.9	10,919.0

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	71.6	23.0	37.4	21.7	78.9	117.4	115.8	183.7	91.7	741.3
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.2
DUK	198.5	111.6	53.7	109.2	280.2	322.9	635.0	523.1	342.0	2,576.2
LGEE	112.9	104.0	77.5	77.8	78.3	134.1	119.6	138.7	111.8	954.7
MISO	2,028.3	1,931.9	2,350.1	1,530.2	2,132.5	2,275.9	1,827.8	2,261.3	2,647.3	18,985.4
ALTE	207.4	268.6	349.4	158.0	217.5	490.0	353.6	432.8	402.2	2,879.5
ALTW	9.5	14.0	29.4	24.0	28.2	36.9	25.4	25.1	40.8	233.2
AMIL	96.6	23.8	68.2	25.1	97.5	34.0	1.9	30.5	364.4	742.0
CIN	391.6	467.9	902.3	411.0	710.3	564.8	453.1	558.5	359.9	4,819.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	6.9	8.8	12.4	30.4	36.6	37.4	23.9	26.9	27.9	211.2
MEC	497.0	439.4	501.2	359.3	541.6	533.1	492.9	541.3	640.7	4,546.6
MECS	248.4	360.0	381.3	446.9	415.0	441.0	377.8	532.4	674.3	3,877.0
NIPS	297.6	268.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	566.0
WEC	273.3	81.2	105.9	75.6	85.8	138.5	99.2	113.9	137.1	1,110.7
NYISO	2,444.8	2,355.3	1,896.5	666.9	761.3	711.7	1,051.5	1,618.1	1,534.3	13,040.3
HUDS	466.4	421.3	347.4	121.5	173.3	128.1	223.3	282.3	320.4	2,484.0
LIND	229.8	214.6	200.1	151.7	226.7	203.4	214.1	203.8	223.2	1,867.3
NEPT	282.0	250.3	282.6	274.2	282.3	271.8	326.7	498.7	483.6	2,952.1
NYIS	1,466.7	1,469.1	1,066.4	119.4	79.0	108.4	287.4	633.3	507.1	5,736.9
TVA	11.4	7.6	23.0	30.9	80.3	271.7	258.5	162.6	79.2	925.2
Total	4,867.6	4,533.4	4,438.2	2,436.6	3,411.5	3,833.7	4,008.3	4,887.6	4,806.3	37,223.3

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[10] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SOUTH interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[11]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[12] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-20 presents the interface pricing points used in the first nine months of 2022. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SOUTH interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a

10 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

11 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

12 See "Interface Pricing Point Assignment Methodology," (June 1, 2021) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

generator is located at the point in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the SOUTH interface pricing point. 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 rather than geographical location. The MMU recommends that PJM review the mappings of external balancing authority pricing points at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The MMU has made multiple recommendations to either retire or consolidate interface pricing points used by PJM. The reasons for those recommendations include: pricing points that could no longer be used to price actual transactions; pricing points that were inappropriately used to support special agreements; pricing points that were treated as multiple pricing points when they were a single pricing point; and pricing points that were noncontiguous to the PJM footprint that created opportunities for sham scheduling. Table 9-6 shows the interface pricing points, the recommendation and the date the recommendation was adopted.

Table 9-6 Interface pricing point recommendations and dates adopted[13]

Interface Pricing Point	Recommendation	Date Adopted
IMO	Retire Pricing Point - Noncontiguous	
Southeast (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
Southwest (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
SOUTHEXP	Consolidate Pricing Points	1-Jun-2021
SOUTHIMP	Consolidate Pricing Points	1-Jun-2021
Southeast	Retire Pricing Point - Support Special Agreements	15-Apr-2021
Southwest	Retire Pricing Point - Support Special Agreements	15-Apr-2021
NCMPAEXP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
NCMPAIMP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
Northwest	Retire Pricing Point - Noncontiguous	1-Oct-2020
CPLEEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
CPLEIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
NIPSCO	Retire Pricing Point - Obsolete (Integration into MISO)	1-Jun-2020
OVEC	Retire Pricing Point - Obsolete (Integration into PJM)	1-Dec-2018

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[14] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag.

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. The top three net exporting interface pricing points in the real-time energy market accounted for 85.2 percent of the total net

13 The Southeast interface pricing point was retired from the day-ahead market only. This pricing point could still be assigned to transactions under the VACAR reserve sharing agreement. Following the termination of the VACAR reserve sharing agreement on October 1, 2022, PJM retired the Southeast and Southwest interface pricing points.

14 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.

scheduled exports: PJM/MISO with 61.6 percent, PJM/NYIS with 13.6 percent and PJM/NEPTUNE with 10.0 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 38.4 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2022, there were net scheduled imports at two of PJM's eight interface pricing points eligible for real-time transactions. The top importing interface pricing point in the real-time energy market was the PJM/SOUTH interface pricing point, which accounted for 68.3 percent of the total net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the real-time energy market.[15]

Table 9-7 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	412.2	276.6	87.3	33.2	19.4	36.1	76.8	51.4	(3.0)	990.1
MISO	(1,914.7)	(1,861.1)	(2,294.4)	(1,463.1)	(2,009.1)	(2,227.9)	(1,692.0)	(2,116.4)	(2,547.2)	(18,125.9)
NYISO	(2,307.9)	(2,241.8)	(1,766.2)	(278.8)	(398.1)	(515.0)	(891.5)	(1,484.2)	(1,414.2)	(11,297.8)
HUDSONTP	(466.4)	(421.3)	(347.3)	(121.5)	(173.3)	(128.1)	(223.3)	(282.3)	(320.4)	(2,483.9)
LINDENVFT	(229.8)	(214.6)	(200.0)	(151.7)	(226.7)	(203.4)	(214.1)	(203.8)	(223.2)	(1,867.2)
NEPTUNE	(282.0)	(250.3)	(282.6)	(274.2)	(282.3)	(271.8)	(326.6)	(498.7)	(483.6)	(2,952.0)
NYIS	(1,329.8)	(1,355.7)	(936.3)	268.6	284.2	88.2	(127.4)	(499.5)	(387.0)	(3,994.7)
SOUTH	774.5	726.0	650.9	829.3	373.1	(278.0)	(660.4)	(399.0)	112.9	2,129.3
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	(3,035.9)	(3,100.3)	(3,322.4)	(879.4)	(2,014.6)	(2,984.9)	(3,167.1)	(3,948.3)	(3,851.4)	(26,304.3)

Table 9-8 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	413.0	279.1	87.4	35.0	20.2	38.5	78.8	65.7	12.1	1,029.8
MISO	92.7	58.3	54.0	63.7	119.0	34.5	112.9	101.3	81.8	718.3
NYISO	136.9	111.2	130.2	388.0	363.2	196.7	159.7	128.5	116.2	1,730.6
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LINDENVFT	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	136.9	111.2	130.1	388.0	363.1	196.6	159.6	128.5	116.2	1,730.3
SOUTH	1,189.1	984.4	844.2	1,070.5	894.6	579.0	489.8	643.8	744.9	7,440.3
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1,831.7	1,433.1	1,115.8	1,557.2	1,396.9	848.8	841.3	939.4	954.9	10,919.0

15 In the real-time energy market, one PJM interface pricing points had a net interchange of zero (Southeast).

Table 9-9 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	0.8	2.5	0.1	1.8	0.8	2.4	2.0	14.3	15.1	39.6
MISO	2,007.4	1,919.4	2,348.3	1,526.8	2,128.1	2,262.5	1,805.0	2,217.7	2,628.9	18,844.1
NYISO	2,444.8	2,353.0	1,896.5	666.9	761.3	711.7	1,051.2	1,612.8	1,530.4	13,028.5
HUDSONTP	466.4	421.3	347.4	121.5	173.3	128.1	223.3	282.3	320.4	2,484.0
LINDENVFT	229.8	214.6	200.1	151.7	226.7	203.4	214.1	203.8	223.2	1,867.3
NEPTUNE	282.0	250.3	282.6	274.2	282.3	271.8	326.7	498.7	483.6	2,952.1
NYIS	1,466.7	1,466.9	1,066.4	119.4	79.0	108.4	287.1	628.0	503.2	5,725.0
SOUTH	414.6	258.5	193.3	241.2	521.4	857.1	1,150.2	1,042.9	631.9	5,311.1
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,867.6	4,533.4	4,438.2	2,436.6	3,411.5	3,833.7	4,008.3	4,887.6	4,806.3	37,223.3

Day-Ahead Interface Imports and Exports

In the day-ahead energy market, as in the real-time energy market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the day-ahead energy market requires fewer steps than in the real-time energy market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the real-time energy market.[16] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the real-time energy market. In the day-ahead energy market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[17]

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-10, Table 9-11, and Table 9-12, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SOUTH as the import pricing point when submitting the transaction in the day-ahead energy market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SOUTH interface pricing point, which reflects the expected power flow.

Table 9-10 through Table 9-12 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the day-ahead energy market is shown by interface for the first nine months of 2022 in Table 9-10, while gross scheduled imports and exports are shown in Table 9-11 and Table 9-12.

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. The top three net exporting

16 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.
17 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

interfaces in the day-ahead energy market accounted for 50.8 percent of the total net scheduled exports: PJM/MidAmerican Energy Company (MEC) with 19.6 percent, PJM/NYIS with 17.1 percent, and PJM/Neptune (NEPT) with 14.2 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 41.9 percent of the total net PJM scheduled exports in the day-ahead energy market. In the first nine months of 2022, there were net exports in the day-ahead energy market at eight of the 10 separate interfaces that connect PJM to MISO. Those eight interfaces represented 47.8 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2022, there were net scheduled imports at one of PJM's 19 interfaces. The top importing interface in the day-ahead energy market was the PJM/Carolina Power and Light - Western (CPLW) Interface, which accounted for 100.0 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the day-ahead energy market. In the first nine months of 2022, there were net imports in the day-ahead energy market at none of the 10 separate interfaces that connect PJM to MISO.[18]

Table 9-10 Day-ahead scheduled net interchange volume by interface (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(28.6)	(1.7)	(20.1)	(11.1)	(29.9)	(23.9)	(38.5)	(45.3)	(16.4)	(215.4)
CPLW	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7
DUK	18.2	11.0	44.5	(49.2)	(103.0)	(8.8)	(205.3)	(180.1)	35.4	(437.4)
LGEE	(107.5)	(101.1)	(75.4)	(78.7)	(71.7)	(144.4)	(130.7)	(128.6)	(107.6)	(945.8)
MISO	(996.7)	(1,066.5)	(1,202.4)	(804.7)	(1,033.7)	(1,304.2)	(1,027.0)	(1,217.6)	(1,413.6)	(10,066.4)
ALTE	(107.6)	(153.6)	(240.2)	(118.2)	(127.7)	(225.5)	(142.8)	(200.4)	(291.6)	(1,607.7)
ALTW	(9.4)	(13.8)	(27.8)	(22.1)	(27.3)	(35.0)	(22.5)	(25.0)	(42.9)	(225.9)
AMIL	(22.0)	(9.0)	(1.5)	(0.6)	3.7	(8.3)	0.0	0.0	(1.5)	(39.1)
CIN	(44.6)	(106.6)	(380.8)	(52.7)	(254.1)	(329.4)	(249.1)	(286.6)	(171.6)	(1,875.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	(497.0)	(405.8)	(458.4)	(324.8)	(488.8)	(485.1)	(481.1)	(491.6)	(482.4)	(4,114.9)
MECS	59.2	(49.9)	(0.5)	(231.1)	(64.1)	(91.5)	(41.3)	(110.3)	(300.1)	(829.7)
NIPS	(297.6)	(268.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(566.0)
WEC	(77.7)	(59.4)	(93.2)	(55.1)	(75.4)	(129.5)	(90.2)	(103.7)	(123.5)	(807.5)
NYISO	(1,895.4)	(1,772.7)	(1,467.0)	(368.3)	(273.0)	(351.7)	(637.8)	(1,099.1)	(964.3)	(8,829.3)
HUDS	(382.2)	(343.1)	(359.0)	(107.5)	(160.0)	(118.3)	(207.8)	(262.1)	(302.2)	(2,242.3)
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	(285.6)	(258.0)	(285.3)	(276.5)	(285.7)	(275.9)	(325.3)	(502.7)	(486.1)	(2,981.2)
NYIS	(1,227.7)	(1,171.5)	(822.6)	15.7	172.7	42.5	(104.7)	(334.3)	(176.0)	(3,605.8)
TVA	9.0	18.2	(0.7)	(18.9)	(49.1)	(197.9)	(188.8)	(75.7)	(51.2)	(555.0)
Total without Up To Congestion	(3,001.1)	(2,912.7)	(2,720.3)	(1,330.9)	(1,560.4)	(2,031.0)	(2,228.0)	(2,746.5)	(2,517.6)	(21,048.6)
Up To Congestion	(120.4)	(532.1)	549.6	374.4	257.1	44.3	70.2	(295.5)	472.0	819.5
Total	(3,121.5)	(3,444.8)	(2,170.8)	(956.5)	(1,303.3)	(1,986.8)	(2,157.9)	(3,042.0)	(2,045.6)	(20,229.1)

18 In the day-ahead energy market, three PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP), PJM Illinois Power and Light (IPL) and PJM/Linden (LIND)).

Table 9-11 Day-ahead scheduled gross import volume by interface (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.1	5.3	0.0	7.3	2.5	0.0	0.0	0.5	2.6	18.1
CPLW	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7
DUK	65.7	74.2	63.9	29.5	21.3	113.1	80.4	106.1	154.0	708.2
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
MISO	140.1	84.2	45.4	46.3	92.6	9.1	41.2	42.8	45.3	547.0
ALTE	51.1	28.5	26.6	32.3	47.3	5.0	28.6	19.9	16.2	255.5
ALTW	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
AMIL	0.1	0.0	0.0	0.0	6.5	0.0	0.0	0.0	0.0	6.5
CIN	14.6	12.9	6.2	11.0	35.1	4.1	7.2	10.7	22.6	124.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	0.0	29.6	0.0	0.0	0.0	0.0	0.0	0.6	0.6	30.8
MECS	71.0	13.2	12.6	2.5	3.8	0.0	5.0	4.1	0.0	112.1
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	3.0	0.0	0.0	0.5	0.0	0.0	0.5	7.5	5.9	17.4
NYISO	0.5	0.0	0.1	78.5	187.9	65.2	41.4	25.3	24.6	423.5
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	0.5	0.0	0.1	78.5	187.9	65.2	41.4	25.3	24.6	423.5
TVA	12.9	18.2	9.2	9.1	10.9	1.9	0.9	41.1	9.5	113.6
Total without Up To Congestion	219.2	181.8	119.2	170.7	315.3	189.2	163.9	215.8	236.3	1,811.5
Up To Congestion	764.1	849.4	1,531.6	845.0	782.4	856.1	1,076.2	1,677.5	1,754.8	10,137.1
Total	983.4	1,031.2	1,650.8	1,015.6	1,097.7	1,045.3	1,240.1	1,893.3	1,991.1	11,948.6

Table 9-12 Day-ahead scheduled gross export volume by interface (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	28.7	6.9	20.1	18.3	32.4	23.9	38.5	45.8	18.9	233.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	47.5	63.1	19.4	78.8	124.4	121.9	285.7	286.2	118.7	1,145.6
LGEE	107.5	101.1	75.4	78.7	71.7	144.4	130.7	128.6	107.9	946.1
MISO	1,136.8	1,150.7	1,247.8	850.9	1,126.3	1,313.3	1,068.2	1,260.5	1,458.8	10,613.4
ALTE	158.7	182.1	266.8	150.5	175.1	230.5	171.3	220.4	307.9	1,863.2
ALTW	9.8	13.8	27.8	22.1	27.3	35.0	22.5	25.0	42.9	226.3
AMIL	22.0	9.0	1.5	0.6	2.8	8.3	0.0	0.0	1.5	45.6
CIN	59.2	119.5	387.1	63.7	289.2	333.5	256.3	297.4	194.2	2,000.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	497.0	435.4	458.4	324.8	488.8	485.1	481.1	492.2	482.9	4,145.7
MECS	11.8	63.1	13.1	233.6	67.8	91.5	46.4	114.3	300.1	941.8
NIPS	297.6	268.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	566.0
WEC	80.7	59.4	93.2	55.6	75.4	129.5	90.7	111.2	129.4	824.9
NYISO	1,895.9	1,772.7	1,467.0	446.8	460.9	416.9	679.2	1,124.5	988.9	9,252.8
HUDS	382.2	343.1	359.0	107.5	160.0	118.3	207.8	262.1	302.2	2,242.3
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	285.6	258.0	285.3	276.5	285.7	275.9	325.3	502.7	486.1	2,981.2
NYIS	1,228.1	1,171.5	822.7	62.8	15.2	22.7	146.1	359.7	200.6	4,029.3
TVA	3.9	0.0	9.9	28.0	60.1	199.8	189.7	116.8	60.6	668.7
Total without Up To Congestion	3,220.3	3,094.5	2,839.6	1,501.5	1,875.7	2,220.2	2,392.0	2,962.3	2,753.9	22,860.0
Up To Congestion	884.5	1,381.5	982.0	470.6	525.3	811.9	1,006.0	1,973.0	1,282.8	9,317.6
Total	4,104.8	4,476.0	3,821.6	1,972.1	2,401.1	3,032.1	3,398.0	4,935.3	4,036.7	32,177.7

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-13 through Table 9-18 show the day-ahead scheduled interchange totals at the interface pricing points. In the first nine months of 2022, up to congestion transactions accounted for 84.8 percent of all scheduled import MW transactions and 29.0 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in the first nine months of 2022, including up to congestion transactions, is shown by interface pricing point in Table 9-13. Scheduled up to congestion transactions by interface pricing point in the first nine months of 2022 are shown in Table 9-14. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-15 and Table 9-17, while gross scheduled import and export up to congestion transactions are shown in Table 9-16 and Table 9-18.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface pricing point with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. At that time, the real-time Southeast and Southwest interface pricing points remained only to support certain grandfathered agreements with specific generating units and to price energy under the reserve sharing agreement with VACAR.[19] The reserve sharing agreement allowed for the transfer of energy during emergencies. Interchange transactions created as part of the reserve sharing agreement were settled at the Southeast interface price. PJM also kept the day-ahead Southeast and Southwest interface pricing points to facilitate long-term day-ahead positions that were entered prior to the consolidation. Following the termination of the VACAR reserve sharing agreement on October 1, 2022, PJM retired the Southeast and Southwest interface pricing points.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the 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.[20] PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

19 The VACAR reserve sharing agreement was terminated on October 1, 2022.

20 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. Following the termination of the VACAR reserve sharing agreement on October 1, 2022, PJM retired the Southeast and Southwest interface pricing points.

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.[21] The top three net exporting interface pricing points in the day-ahead energy market accounted for 69.5 percent of the total net scheduled exports: PJM/SOUTH with 24.1 percent, PJM/NYIS with 22.7 percent and PJM/MISO with 22.7 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 50.9 percent of the total net PJM scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2022, there were net scheduled imports at none of PJM's seven interface pricing points eligible for day-ahead transactions. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2022, up to congestion transactions had net scheduled exports at five of PJM's seven interface pricing points eligible for day-ahead transactions.[22] The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 75.7 percent of the total net up to congestion scheduled exports: PJM/SOUTH with 55.5 percent and PJM/NYIS with 20.2 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 31.4 percent of the total net scheduled up to congestion exports in the day-ahead energy market. However, the PJM/NEPTUNE interface pricing points had net up to congestion scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2022, up to congestion transactions had net scheduled imports at two of PJM's seven interface pricing points eligible for day-ahead transactions. The top importing interface pricing points eligible for up to congestion transactions accounted for 98.9 percent of the total up to congestion scheduled imports: PJM/MISO with 98.9 percent of the net up to congestion scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 1.1 percent of the total net scheduled up to congestion imports in the day-ahead energy market. However, the PJM/HUDSONTP, PJM/LINDENVFT and PJM/NYIS interface pricing points had net up to congestion scheduled exports in the day-ahead energy market.

Table 9-13 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(84.5)	(580.7)	(103.1)	29.9	21.1	57.7	82.2	56.8	46.9	(473.8)
MISO	(1,109.2)	(1,026.6)	(233.4)	(565.1)	(775.9)	(759.0)	(247.7)	168.9	(45.9)	(4,593.9)
NYISO	(2,220.7)	(2,230.9)	(1,871.7)	(410.2)	(323.9)	(379.2)	(708.9)	(1,126.4)	(1,023.8)	(10,295.6)
HUDSONTP	(427.0)	(408.3)	(451.3)	(108.1)	(263.9)	(132.5)	(217.9)	(303.0)	(392.1)	(2,704.1)
LINDENVFT	(68.2)	(35.7)	(19.1)	7.1	2.3	4.5	(1.5)	9.0	6.4	(95.2)
NEPTUNE	(296.6)	(248.8)	(251.8)	(265.9)	(296.9)	(297.3)	(328.3)	(468.9)	(447.9)	(2,902.3)
NYIS	(1,429.0)	(1,538.1)	(1,149.6)	(43.3)	234.7	45.9	(161.1)	(363.5)	(190.1)	(4,594.0)
SOUTH	293.0	393.4	37.3	(11.1)	(224.6)	(906.3)	(1,283.5)	(2,141.3)	(1,022.8)	(4,865.8)
Total	(3,121.5)	(3,444.8)	(2,170.8)	(956.5)	(1,303.3)	(1,986.8)	(2,157.9)	(3,042.0)	(2,045.6)	(20,229.1)

21 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.

22 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.

Table 9-14 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(164.5)	(624.6)	(118.3)	22.9	15.9	57.3	75.8	52.2	46.9	(636.4)
MISO	(35.0)	83.9	984.3	244.7	263.7	545.6	785.6	1,367.5	1,365.0	5,605.3
NYISO	(322.8)	(458.2)	(404.7)	(40.0)	(50.9)	(27.5)	(71.1)	(25.0)	(57.7)	(1,457.9)
HUDSONTP	(44.8)	(65.2)	(92.3)	(0.5)	(103.9)	(14.1)	(10.1)	(41.0)	(89.9)	(461.9)
LINDENVFT	(68.2)	(35.7)	(19.1)	7.1	2.3	4.5	(1.5)	9.0	22.1	(79.4)
NEPTUNE	(11.0)	9.3	33.6	10.6	(11.2)	(21.3)	(3.0)	33.8	22.4	63.2
NYIS	(198.9)	(366.6)	(326.9)	(57.1)	62.0	3.4	(56.5)	(26.9)	(12.4)	(979.8)
SOUTH	401.9	466.9	88.3	146.8	28.3	(531.2)	(720.2)	(1,690.1)	(882.1)	(2,691.4)
Total Interfaces	(120.4)	(532.1)	549.6	374.4	257.1	44.3	70.2	(295.5)	472.0	819.5
INTERNAL	4,620.3	5,929.6	5,803.0	5,305.5	5,245.0	5,872.1	6,419.1	8,438.6	6,954.8	54,588.1
Total	4,499.9	5,397.5	6,352.6	5,679.9	5,502.1	5,916.4	6,489.3	8,143.1	7,426.8	55,407.6

Table 9-15 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	104.2	54.9	72.7	52.2	34.6	68.2	87.2	68.1	58.8	600.9
MISO	297.0	316.1	1,201.9	501.1	568.2	711.8	896.3	1,484.8	1,510.1	7,487.2
NYISO	87.5	91.9	81.7	172.2	332.6	126.1	123.8	146.1	154.1	1,315.9
HUDSONTP	19.8	20.4	11.4	23.8	9.4	7.8	26.2	19.8	21.4	160.2
LINDENVFT	10.6	8.9	11.2	12.5	9.7	10.5	8.7	21.5	37.5	131.1
NEPTUNE	15.5	18.8	41.3	18.1	22.0	12.4	14.5	49.1	37.9	229.7
NYIS	41.5	43.8	17.7	117.7	291.4	95.3	74.4	55.7	57.2	794.9
SOUTH	494.6	568.3	294.6	290.2	162.4	139.2	132.8	194.4	268.1	2,544.6
Total	983.4	1,031.2	1,650.8	1,015.6	1,097.7	1,045.3	1,240.1	1,893.3	1,991.1	11,948.6

Table 9-16 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	24.2	11.0	57.5	45.2	29.4	67.8	80.8	63.5	58.8	438.2
MISO	236.9	275.9	1,171.7	461.8	481.5	703.1	861.5	1,446.6	1,464.8	7,103.7
NYISO	87.1	91.9	81.6	93.7	144.6	60.9	82.4	120.7	129.4	892.4
HUDSONTP	19.8	20.4	11.4	23.8	9.4	7.8	26.2	19.8	21.4	160.2
LINDENVFT	10.6	8.9	11.2	12.5	9.7	10.5	8.7	21.5	37.5	131.1
NEPTUNE	15.5	18.8	41.3	18.1	22.0	12.4	14.5	49.1	37.9	229.7
NYIS	41.1	43.8	17.7	39.2	103.5	30.1	33.0	30.4	32.6	371.4
SOUTH	416.0	470.7	220.8	244.2	126.9	24.3	51.5	46.7	101.8	1,702.9
Total Interfaces	764.1	849.4	1,531.6	845.0	782.4	856.1	1,076.2	1,677.5	1,754.8	10,137.1

Table 9-17 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	188.7	635.6	175.7	22.3	13.5	10.5	5.0	11.3	11.9	1,074.6
MISO	1,406.3	1,342.7	1,435.2	1,066.2	1,344.1	1,470.7	1,144.0	1,315.9	1,556.0	12,081.1
NYISO	2,308.2	2,322.8	1,953.4	582.4	656.4	505.3	832.7	1,272.4	1,177.8	11,611.4
HUDSONTP	446.8	428.7	462.7	131.9	273.4	140.3	244.2	322.8	413.5	2,864.3
LINDENVFT	78.8	44.6	30.3	5.5	7.4	6.0	10.2	12.4	31.2	226.2
NEPTUNE	312.1	267.6	293.1	284.0	318.9	309.7	342.9	518.0	485.8	3,132.0
NYIS	1,470.5	1,582.0	1,167.3	161.0	56.7	49.3	235.5	419.2	247.4	5,388.9
SOUTH	201.7	174.9	257.3	301.3	387.0	1,045.5	1,416.3	2,335.7	1,290.9	7,410.5
Total	4,104.8	4,476.0	3,821.6	1,972.1	2,401.1	3,032.1	3,398.0	4,935.3	4,036.7	32,177.7

Table 9-18 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	188.7	635.6	175.7	22.3	13.5	10.5	5.0	11.3	11.9	1,074.6
MISO	271.8	192.0	187.4	217.2	217.8	157.4	75.8	79.1	99.8	1,498.4
NYISO	409.9	550.1	486.3	133.7	195.5	88.4	153.5	145.7	187.1	2,350.3
HUDSONTP	64.6	85.6	103.7	24.4	113.3	22.0	36.4	60.8	111.3	622.0
LINDENVFT	78.8	44.6	30.3	5.5	7.4	6.0	10.2	12.4	15.4	210.5
NEPTUNE	26.5	9.6	7.7	7.5	33.2	33.8	17.5	15.2	15.4	166.5
NYIS	239.9	410.4	344.6	96.3	41.5	26.7	89.5	57.3	45.0	1,351.2
SOUTH	14.1	3.7	132.6	97.5	98.5	555.5	771.7	1,736.9	983.9	4,394.3
Total Interfaces	884.5	1,381.5	982.0	470.6	525.3	811.9	1,006.0	1,973.0	1,282.8	9,317.6

Table 9-19 Active scheduling interfaces: January through September, 2022[23]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

23 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of September 30, 2022, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Figure 9-3 PJM's footprint and its external scheduling interfaces

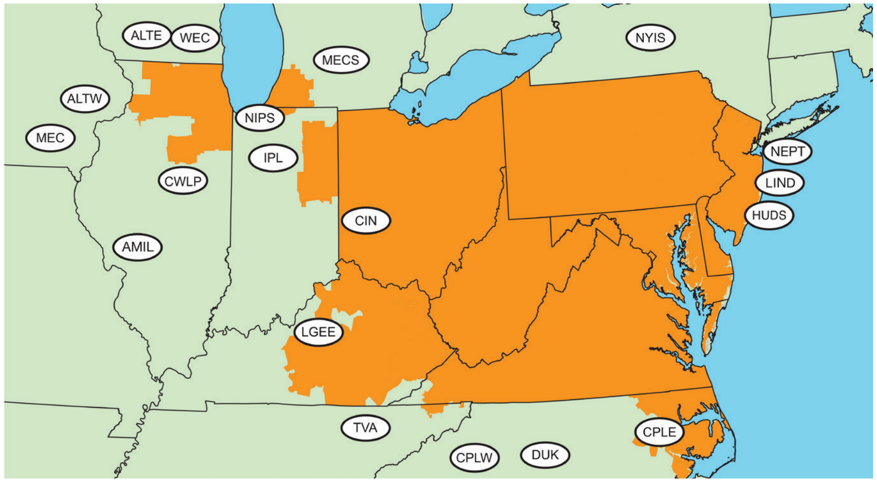
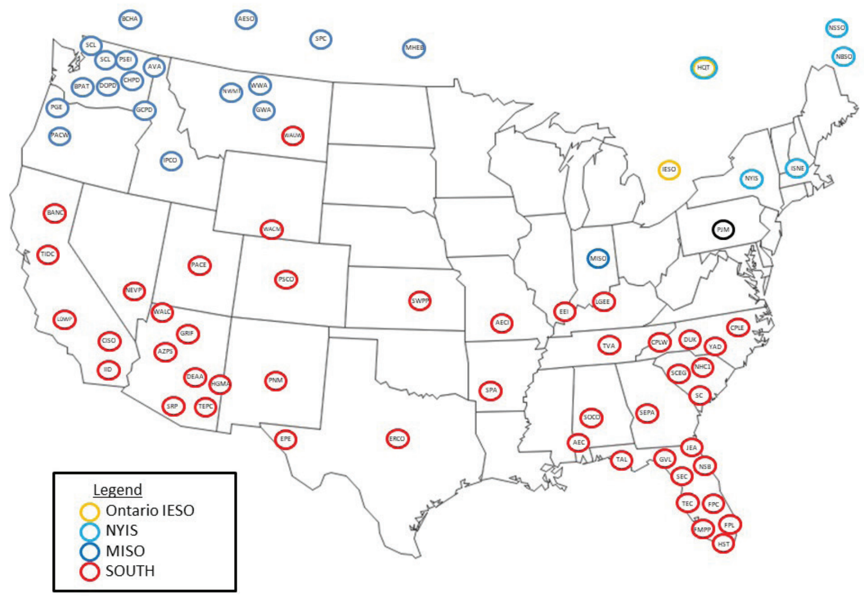


Table 9-20 Active scheduled interface pricing points: January through September, 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTH	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEAST	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-4 External balancing authority default interface pricing point assignments



Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[24]

24 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/Southern interface border, but there would be 100 MW of actual flows on the interface. In the first nine months of 2022, there were net scheduled flows of 3,057.6 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first nine months of 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, net scheduled interchange was -29,504.6 GWh and net actual interchange was -29,574.3 GWh, a difference of 69.7 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-21 shows that PJM had 99.6 GW of inadvertent interchange in the first nine months of 2022. To reduce this inadvertent interchange, PJM can control to an ACE greater than zero, which would result in over generating. By way of the power balance equation, power would flow out of PJM to its neighboring balancing authority areas. This would create additional actual exports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[25]

Table 9-21 shows that 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.

25 See PJM. "Manual 12: Balancing Operations," Rev. 47 (October 1, 2022).

Table 9-21 Net scheduled and actual PJM flows by interface (GWh): January through September, 2022

	Actual	Net Scheduled	Difference (GWh)
CPLE	750.7	(560.2)	1,310.9
CPLW	(499.1)	3.5	(502.6)
DUK	687.6	(463.7)	1,151.2
LGEE	1,447.9	(798.2)	2,246.1
MISO	(21,830.1)	(14,127.4)	(7,702.7)
ALTE	(826.5)	(2,534.4)	1,707.9
ALTW	(733.2)	(232.9)	(500.3)
AMIL	(472.9)	1,662.2	(2,135.1)
CIN	(4,900.2)	(4,380.4)	(519.8)
CWLP	(242.0)	0.0	(242.0)
IPL	(2,216.7)	(160.1)	(2,056.6)
MEC	(4,525.6)	(4,372.0)	(153.6)
MECS	(3,629.2)	(2,950.7)	(678.5)
NIPS	(8,681.3)	(566.0)	(8,115.3)
WEC	4,397.5	(593.1)	4,990.7
NYISO	(11,019.0)	(11,248.5)	229.5
HUDS	(2,483.9)	(2,483.9)	0.0
LIND	(1,867.2)	(1,867.2)	0.0
NEPT	(2,952.0)	(2,952.0)	0.0
NYIS	(3,715.9)	(3,945.4)	229.5
TVA	4,257.3	890.2	3,367.2
Total	(26,204.7)	(26,304.3)	99.6

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[26] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SOUTH interface pricing point net schedule totals because SPP is mapped to the SOUTH interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

26 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path. Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-22 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-22 PJM flows by interface pricing point (GWh): January through September, 2022

	Actual	Net Scheduled	Difference (GWh)
IMO	0.0	990.1	(990.1)
MISO	(21,830.1)	(18,125.9)	(3,704.2)
NYISO	(11,019.0)	(11,297.8)	278.8
HUDSONTP	(2,483.9)	(2,483.9)	0.0
LINDENVFT	(1,867.2)	(1,867.2)	0.0
NEPTUNE	(2,952.0)	(2,952.0)	0.0
NYIS	(3,715.9)	(3,994.7)	278.8
SOUTH	6,644.4	2,129.3	4,515.1
SOUTHEAST	0.0	0.0	0.0
Total	(26,204.7)	(26,304.3)	99.6

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market. For example, Table 9-25 shows that 941.9 of the 991.2 GWh (95.0 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO.

Table 9-23 shows that 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.

Table 9-23 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2022

	Actual	Net Scheduled	Difference (GWh)
MISO	(21,830.1)	(17,185.1)	(4,645.0)
NYISO	(11,019.0)	(11,248.5)	229.5
HUDSONTP	(2,483.9)	(2,483.9)	0.0
LINDENVFT	(1,867.2)	(1,867.2)	0.0
NEPTUNE	(2,952.0)	(2,952.0)	0.0
NYIS	(3,715.9)	(3,945.4)	229.5
SOUTH	6,644.4	2,129.3	4,515.1
SOUTHEAST	0.0	0.0	0.0
Total	(26,204.7)	(26,304.3)	99.6

The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-24 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-24 shows that in the first nine months of 2022, the majority of imports to the PJM energy market for which a market participant specified Ameren-Illinois (AMIL) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SOUTH Interface, and thus actual flows were assigned the SOUTH interface pricing point (2,201.6 GWh). The majority of exports from the PJM energy market for which a market participant specified AMIL as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-737.3 GWh).

Table 9-24 Net scheduled and actual flows by interface and interface pricing point (GWh): January through September, 2022

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(826.5)	(2,534.4)	1,707.9	LGEE		1,447.9	(798.2)	2,246.1
	IMO	0.0	21.4	(21.4)		SOUTH	1,447.9	(798.2)	2,246.1
	MISO	(826.5)	(2,578.1)	1,751.7	LIND		(1,867.2)	(1,867.2)	0.0
	SOUTH	0.0	22.3	(22.3)		LINDENVFT	(1,867.2)	(1,867.2)	0.0
ALTW		(733.2)	(232.9)	(500.3)	MEC		(4,525.6)	(4,372.0)	(153.6)
	MISO	(733.2)	(232.9)	(500.3)		IMO	0.0	27.3	(27.3)
AMIL		(472.9)	1,662.2	(2,135.1)		MISO	(4,525.6)	(4,399.8)	(125.9)
	IMO	0.0	197.9	(197.9)		SOUTH	0.0	0.5	(0.5)
	MISO	(472.9)	(737.3)	264.4	MECS		(3,629.2)	(2,950.7)	(678.5)
	SOUTH	0.0	2,201.6	(2,201.6)		IMO	0.0	649.4	(649.4)
CIN		(4,900.2)	(4,380.4)	(519.8)		MISO	(3,629.2)	(3,822.5)	193.2
	IMO	0.0	(1.1)	1.1		SOUTH	0.0	222.3	(222.3)
	MISO	(4,900.2)	(4,521.3)	(378.9)	NEPT		(2,952.0)	(2,952.0)	0.0
	SOUTH	0.0	142.0	(142.0)		NEPTUNE	(2,952.0)	(2,952.0)	0.0
CPLE		750.7	(560.2)	1,310.9	NIPS		(8,681.3)	(566.0)	(8,115.3)
	SOUTH	750.7	(560.2)	1,310.9		MISO	(8,681.3)	(566.0)	(8,115.3)
CPLW		(499.1)	3.5	(502.6)	NYIS		(3,715.9)	(3,945.4)	229.5
	SOUTH	(499.1)	3.5	(502.6)		IMO	0.0	49.3	(49.3)
CWLP		(242.0)	0.0	(242.0)		NYIS	(3,715.9)	(3,994.7)	278.8
	MISO	(242.0)	0.0	(242.0)	TVA		4,257.3	890.2	3,367.2
DUK		687.6	(463.7)	1,151.2		SOUTH	4,257.3	890.2	3,367.2
	SOUTH	687.6	(463.7)	1,151.2	WEC		4,397.5	(593.1)	4,990.7
HUDS		(2,483.9)	(2,483.9)	0.0		MISO	4,397.5	(1,057.6)	5,455.1
	HUDSONTP	(2,483.9)	(2,483.9)	0.0		SOUTH	0.0	464.5	(464.5)
IPL		(2,216.7)	(160.1)	(2,056.6)	Grand Total		(26,204.7)	(26,304.3)	99.6
	IMO	0.0	45.9	(45.9)					
	MISO	(2,216.7)	(210.4)	(2,006.3)					
	SOUTH	0.0	4.4	(4.4)					

Table 9-25 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-24. Table 9-25 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-25 shows that in the first nine months of 2022, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the SOUTH interface pricing point, had a path that entered the PJM energy market at the AMIL Interface (2,201.6 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the SOUTH interface pricing point, had a path that would leave the PJM energy market at the LGEE Interface (-798.2 GWh).

Table 9-25 Net scheduled and actual flows by interface pricing point and interface (GWh): January through September, 2022

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
HUDSONTP		(2,483.9)	(2,483.9)	0.0	NEPTUNE		(2,952.0)	(2,952.0)	0.0
	HUDS	(2,483.9)	(2,483.9)	0.0		NEPT	(2,952.0)	(2,952.0)	0.0
IMO		0.0	990.1	(990.1)	NYIS		(3,715.9)	(3,994.7)	278.8
	ALTE	0.0	21.4	(21.4)		NYIS	(3,715.9)	(3,994.7)	278.8
	AMIL	0.0	197.9	(197.9)	SOUTH		6,644.4	2,129.3	4,515.1
	CIN	0.0	(1.1)	1.1		ALTE	0.0	22.3	(22.3)
	IPL	0.0	45.9	(45.9)		AMIL	0.0	2,201.6	(2,201.6)
	MEC	0.0	27.3	(27.3)		CIN	0.0	142.0	(142.0)
	MECS	0.0	649.4	(649.4)		CPLE	750.7	(560.2)	1,310.9
	NYIS	0.0	49.3	(49.3)		CPLW	(499.1)	3.5	(502.6)
LINDENVFT		(1,867.2)	(1,867.2)	0.0		DUK	687.6	(463.7)	1,151.2
	LIND	(1,867.2)	(1,867.2)	0.0		IPL	0.0	4.4	(4.4)
MISO		(21,830.1)	(18,125.9)	(3,704.2)		LGEE	1,447.9	(798.2)	2,246.1
	ALTE	(826.5)	(2,578.1)	1,751.7		MEC	0.0	0.5	(0.5)
	ALTW	(733.2)	(232.9)	(500.3)		MECS	0.0	222.3	(222.3)
	AMIL	(472.9)	(737.3)	264.4		TVA	4,257.3	890.2	3,367.2
	CIN	(4,900.2)	(4,521.3)	(378.9)		WEC	0.0	464.5	(464.5)
	CWLP	(242.0)	0.0	(242.0)	Grand Total		(26,204.7)	(26,304.3)	99.6
	IPL	(2,216.7)	(210.4)	(2,006.3)					
	MEC	(4,525.6)	(4,399.8)	(125.9)					
	MECS	(3,629.2)	(3,822.5)	193.2					
	NIPS	(8,681.3)	(566.0)	(8,115.3)					
	WEC	4,397.5	(1,057.6)	5,455.1					

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[27]

27 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[28]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

28 141 FERC ¶ 61,235 (2012).

Area Control Error (ACE) Data

Area control error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual websites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs. The interface definitions led to questions about the level of congestion included in interchange pricing.[29]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Real-Time and Day-Ahead PJM/MISO Interface Prices

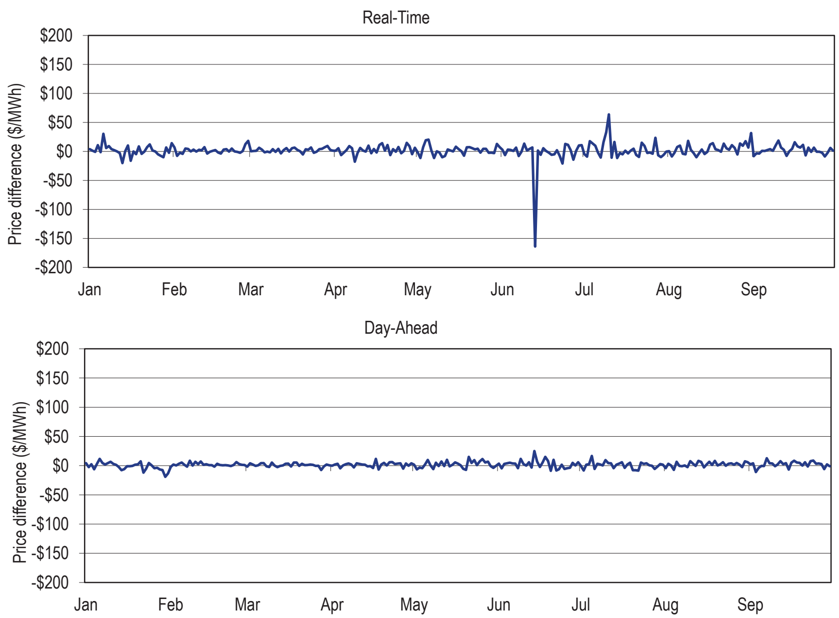
In the first nine months of 2022, the direction of flow was consistent with price differentials in 54.3 percent of the hours. Table 9-26 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Table 9-26 shows that PJM was a net exporter of energy to MISO in all but 20 hours during the first nine months of 2022. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first nine months of 2022, flows were in the uneconomic direction on the PJM/MISO interface in 45.7 percent of all hours. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

29 See "LMP Aggregate Definitions," (September 14, 2022) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

Table 9-26 PJM and MISO flow based hours and price differences: January through September, 2022

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	3,560	$14.55
	Consistent Flow (PJM to MISO)	3,548	$14.55
	Inconsistent Flow (MISO to PJM)	12	$16.20
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	2,991	$13.22
	Consistent Flow (MISO to PJM)	8	$15.24
	Inconsistent Flow (PJM to MISO)	2,983	$13.21
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through September, 2022



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first nine months of 2022, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 3,556 hours (54.3 percent of all hours), and was inconsistent with price differentials in 2,995 hours (45.7 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 2,995 hours where flows were in a direction inconsistent with price differences, 2,703 of those hours (90.3 percent) had a price difference greater than or equal to $1.00 and 1,774 of those hours (59.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,852.55. Of the 3,556 hours where flows were consistent with price differences, 3,251 of those hours (91.4 percent) had a price difference greater than or equal to $1.00 and 2,146 of all such hours (60.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $848.01.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2022

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	2,995	100.0%	3,556	100.0%
$1.00	2,703	90.3%	3,251	91.4%
$5.00	1,774	59.2%	2,146	60.3%
$10.00	1,115	37.2%	1,272	35.8%
$15.00	725	24.2%	822	23.1%
$20.00	484	16.2%	522	14.7%
$25.00	344	11.5%	387	10.9%
$50.00	98	3.3%	175	4.9%
$75.00	34	1.1%	91	2.6%
$100.00	18	0.6%	63	1.8%
$200.00	8	0.3%	22	0.6%
$300.00	4	0.1%	10	0.3%
$400.00	4	0.1%	6	0.2%
$500.00	4	0.1%	4	0.1%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[30]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. Prior to May 1, 2017, PJM used two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP. The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first nine months of 2022, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 60.5 percent of the hours in the first nine months of 2022. Table 9-28 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

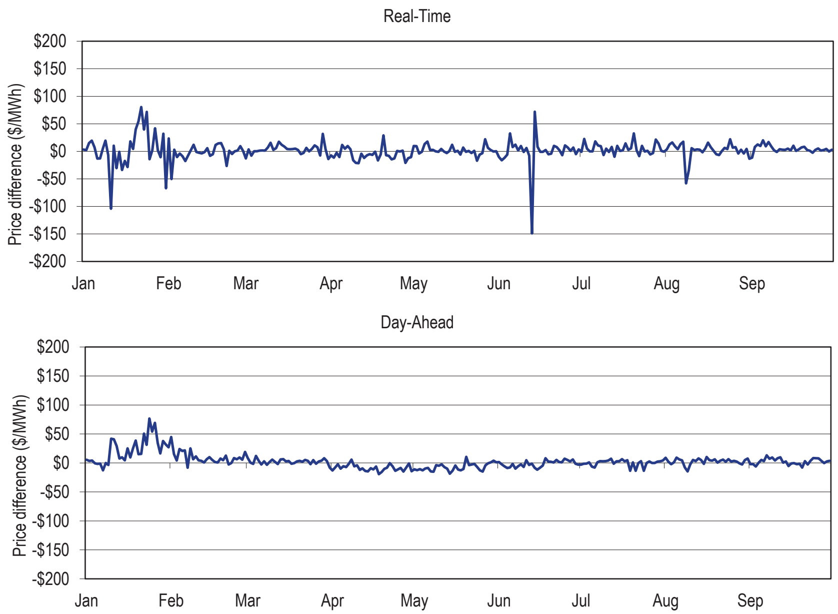
Table 9-28 PJM and NYISO flow based hours and price differences: January through September, 2022[31]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,771	$20.06
	Consistent Flow (PJM to NYIS)	2,794	$19.53
	Inconsistent Flow (NYIS to PJM)	977	$21.58
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	2,780	$23.71
	Consistent Flow (NYIS to PJM)	1,172	$20.38
	Inconsistent Flow (PJM to NYIS)	1,608	$26.14
	No Flow	0	$0.00

30 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

31 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): January through September, 2022



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first nine months of 2022, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,966 hours (60.5 percent of all hours), and was inconsistent with price differences in 2,585 hours (39.5 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 2,585 hours where flows were in a direction inconsistent with price differences, 2,389 of those hours (92.4 percent) had a price difference greater than or equal to $1.00 and 1,786 of all those hours (69.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,057.03. Of the 3,966 hours where flows were consistent with price differences, 3,776 of those hours (95.2 percent) had a price difference greater than or equal to $1.00 and 2,937 of all such hours (74.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $2,157.26.

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2022

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	2,585	100.0%	3,966	100.0%
$1.00	2,389	92.4%	3,776	95.2%
$5.00	1,786	69.1%	2,937	74.1%
$10.00	1,310	50.7%	1,965	49.5%
$15.00	957	37.0%	1,328	33.5%
$20.00	730	28.2%	941	23.7%
$25.00	565	21.9%	712	18.0%
$50.00	283	10.9%	275	6.9%
$75.00	169	6.5%	159	4.0%
$100.00	107	4.1%	99	2.5%
$200.00	34	1.3%	31	0.8%
$300.00	17	0.7%	12	0.3%
$400.00	12	0.5%	8	0.2%
$500.00	8	0.3%	6	0.2%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-30, including average prices and measures of variability.

Table 9-30 PJM, NYISO and MISO border price averages: January through September, 2022[32]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$69.51	$63.85	$68.54	$66.05
	ISO Price at PJM Border	$71.01	$65.72	$70.88	$67.50
	Difference at Border (PJM-ISO)	($1.50)	($1.87)	($2.34)	($1.45)
	Average Absolute Value of Interval Difference at Border	$81.92	$73.54	$11.53	$5.99
	Sign Changes per Day	35.8	47.1	2.2	3.1
Standard Deviation	PJM Price at ISO Border	$77.68	$58.58	$28.83	$31.61
	ISO Price at PJM Border	$68.05	$70.29	$31.26	$30.89
	Difference at Border (PJM-ISO)	$86.34	$75.83	$14.88	$8.51

Neptune Underwater Transmission Line to Long Island, New York

The Neptune Line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. The flows were consistent with price differentials in 85.7 percent of the hours in the first nine months of 2022. Table 9-31 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and price differences (Neptune): January through September, 2022

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	5,617	$41.64
	Consistent Flow (PJM to NYIS)	5,617	$41.64
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	934	$32.47
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	934	$32.47
	No Flow	0	$0.00

32 Effective April 1, 2018, PJM implemented 5 minute LMP settlements in the real-time energy market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the real-time energy market, there are 288 five minute intervals. For the day-ahead market there are 24 hourly intervals.

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC Line ("Neptune Service").[33] The PJM Out Service is covered by normal PJM OASIS business operations.[34] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On September 30, 2022, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

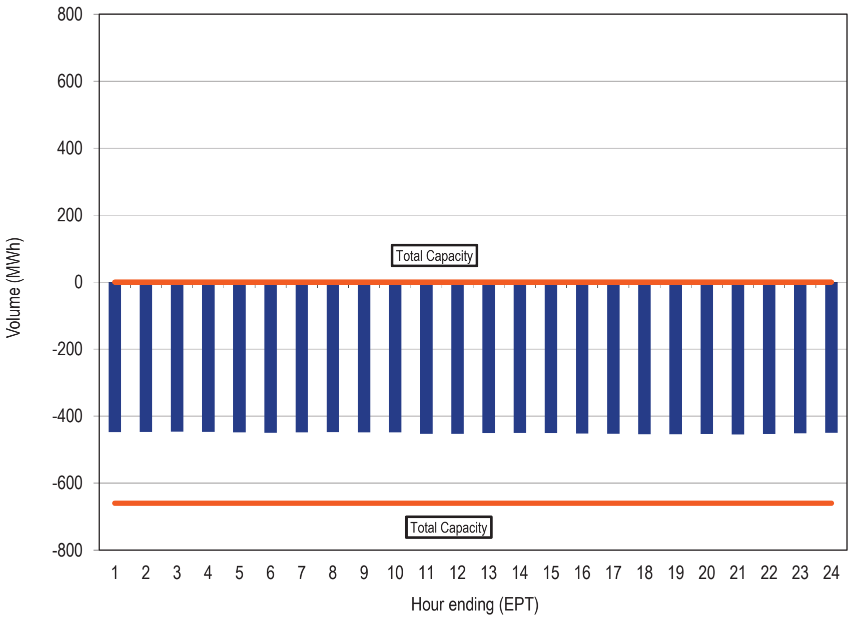
Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-32 shows that in the first nine months of 2022, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first nine months of 2022.

Table 9-32 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through September 2022

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

33 See OASIS "PJM Business Practices for Neptune Transmission Service," (August 21, 2015) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.
34 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 10 (October 27, 2021) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Figure 9-7 Neptune hourly average flow: January through September, 2022



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 78.0 percent of the hours in the first nine months of 2022. Table 9-33 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden Bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and price differences (Linden): January through September, 2022

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	5,193	$28.49
	Consistent Flow (PJM to NYIS)	5,113	$28.65
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	80	$18.36
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	1,358	$43.55
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,329	$44.17
	No Flow	29	$14.94

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On September 30, 2022, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

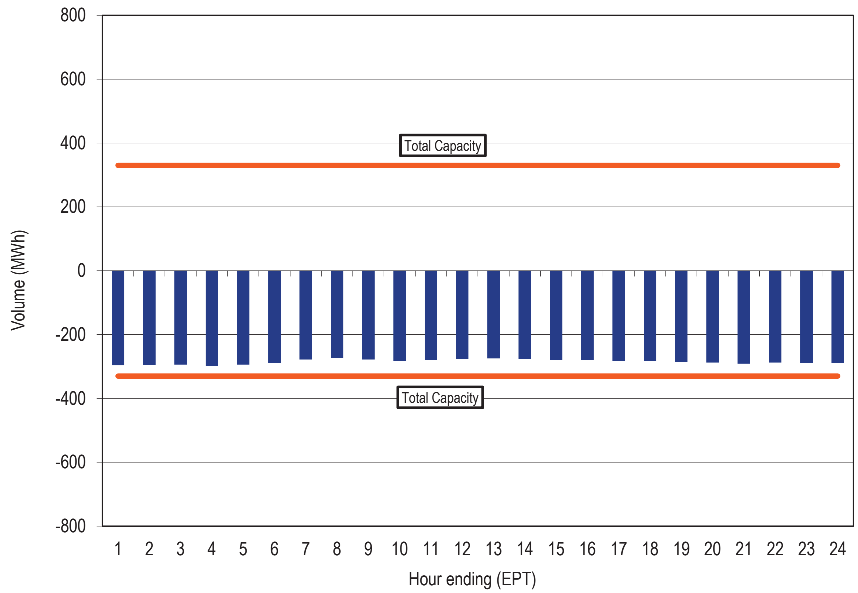
35 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.
36 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 10 (October 27, 2021) <https://www.pjm.com/-/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in the first nine months of 2022, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first nine months of 2022.

Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through September 2022

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through September, 2022[37]



37 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 75.1 percent of the hours in the first nine months of 2022. Table 9-35 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-35 PJM and NYISO flow based hours and price differences (Hudson): January through September, 2022

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	5,036	$29.28
	Consistent Flow (PJM to NYIS)	4,919	$29.48
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	117	$21.06
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	1,515	$30.77
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,508	$30.89
	No Flow	7	$4.26

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[38] The PJM Out Service is covered by normal PJM OASIS business operations.[39] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On September 30, 2022, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

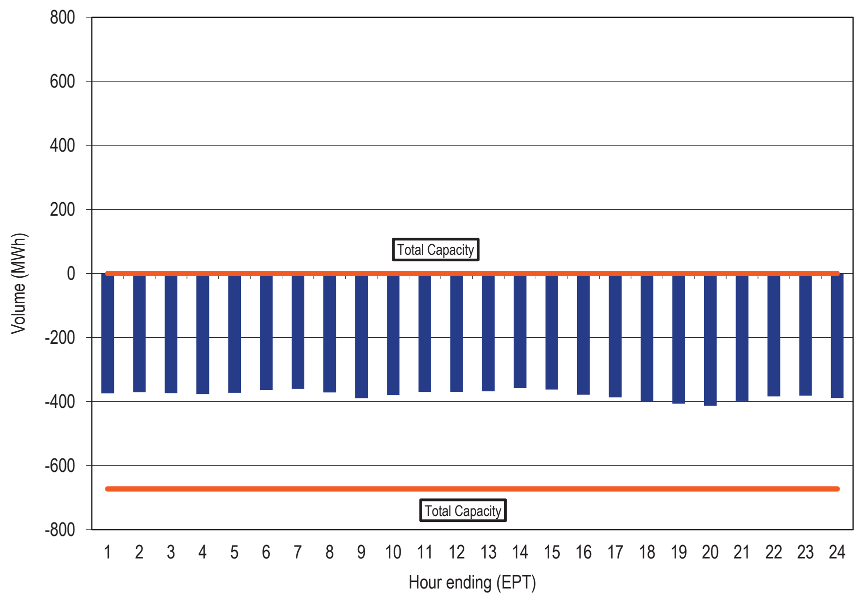
Table 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in the first nine months of 2022, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Hudson Line in June through September and the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson Line the remaining months. Figure 9-9 shows the hourly average flow across the Hudson Line for the first nine months of 2022.

38 See OASIS "PJM Business Practices for Hudson Transmission Service,"<http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.
39 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 10 (October 27, 2021) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through September 2022[40]

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%	37.64%	64.30%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%	47.37%	64.34%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%	53.27%	82.65%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%	70.90%	84.91%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%	65.15%	84.15%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%	73.81%	100.00%
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%	76.56%	100.00%
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%	59.09%	100.00%
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%	53.66%	100.00%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	52.58%	56.26%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%	65.24%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%	61.11%	

Figure 9-9 Hudson hourly average flow: January through September, 2022



Interchange Activity During High Load Hours

The PJM metered system peak load during the first nine months of 2022 was 144,356 MW in the HE 1800 on July 20, 2022. PJM was a net scheduled exporter of energy in all hours on July 20, 2022, with average hourly scheduled exports of 3,937 MW. During HE 1800 on July 20, 2022, PJM had net scheduled exports of 3,925 MW and net metered actual exports of 3,848 MW. Net transaction exports during this time were inconsistent with the price differences between PJM and the NYISO and MISO. Net transaction exports during this time were consistent with price differences between the PJM/NEPT Interface and the NYIS/Neptune bus, the PJM/LIND Interface and the NYIS/Linden Bus and the PJM/HUDS Interface and the NYIS/Hudson Bus. During July 2022, PJM was a net scheduled exporter of energy in 743 of the 744 hours (99.9 percent). During July 2022, the average hourly scheduled interchange was -4,257 MW (representing 4.2 percent of the average hourly load of 102,357 MW in July 2022).

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-37 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

40 The designation of "NA" means there was no flow on the Hudson Line during those months.

Table 9-37 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	NO	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[41]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[42]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[43] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

An operating entity is an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads and other operating entities.[44] Coordinated flowgates are identified to determine which flowgates an operating entity affects significantly. This set of flowgates may then be used in the congestion management process. An operating entity will conduct sensitivity studies to determine which flowgates are significantly affected by the flows of the operating entity's control zones (historic control areas that existed in the IDC). An operating entity identifies these flowgates by performing five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. An operating entity may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use

41 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
42 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.
43 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
44 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

the TLR process to manage congestion.[45] A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

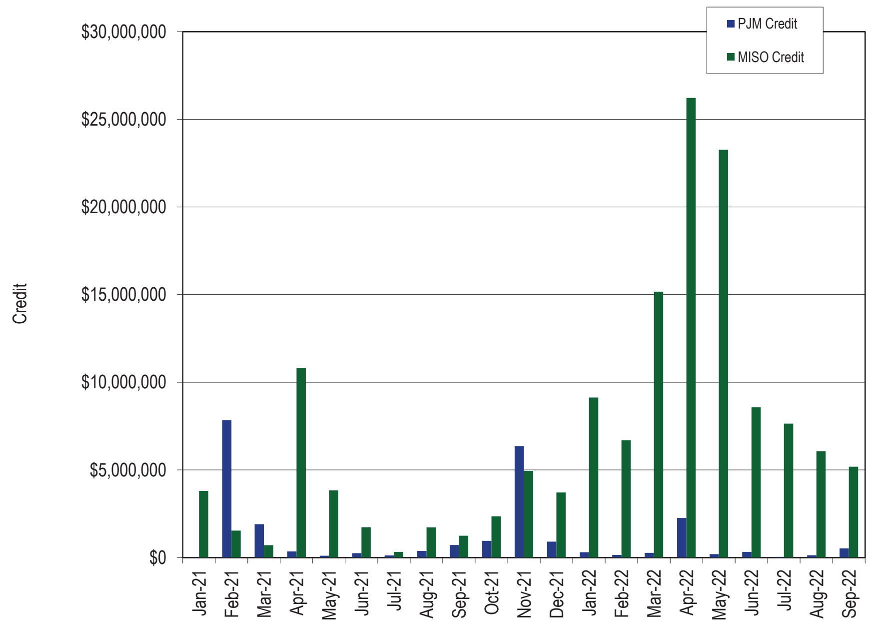
As of January 1, 2022, PJM had 179 flowgates eligible for M2M (Market to Market) coordination. In the first nine months of 2022, PJM added 13 flowgates and deleted one flowgate, resulting in 191 flowgates eligible for M2M coordination as of September 30, 2022. As of January 1, 2022, MISO had 157 flowgates eligible for M2M coordination. In the first nine months of 2022, MISO added 39 flowgates and deleted 59 flowgates, resulting in 137 flowgates eligible for M2M coordination as of September 30, 2022.

The firm flow entitlement (FFE) represents the amount of historic 2004 flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the nonmonitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic premarket firm flows as of that date. In the past 16 years, topology and market changes have occurred, making the 2004 flows irrelevant in 2022. The RTOs and stakeholders recognize that a modification to the freeze date is necessary.[46] PJM and MISO stakeholders have spent several years on the freeze date issues. Discussions regarding the Firm Flow Limit (FFL) solutions between market and nonmarket areas are also ongoing. No resolution to these issues appears imminent. The final resolution to the freeze date alternative should account for the investments made by each RTO in the transmission system. 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.

In the first nine months of 2022, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2021 through September 2022[47]



45 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

46 See "*Freeze Date Alternatives*," (May 21, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20190521/20190521-item-01-freeze-date-update.ashx>.

47 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[48]

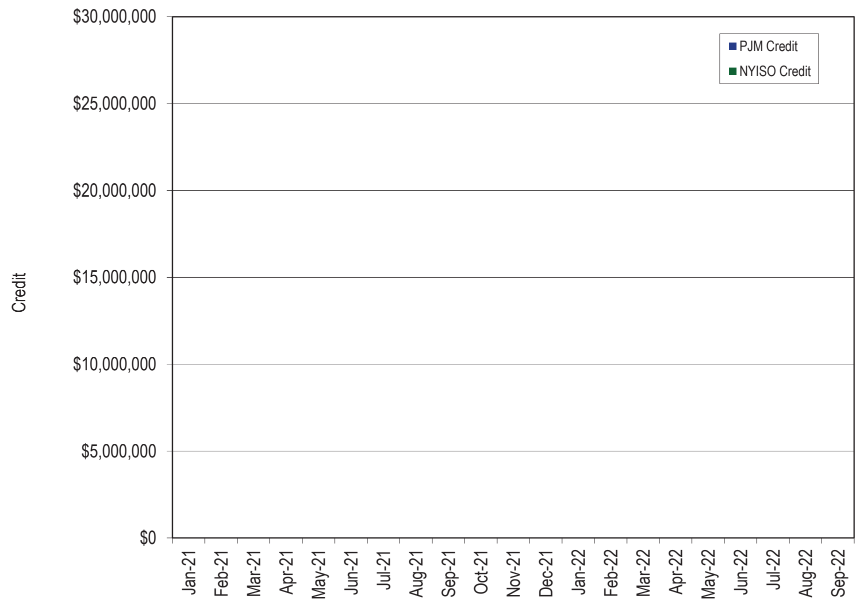
The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions would address RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch would be to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows for the RTOs to control for this contingency without the exchange of payments for redispatch.[49]

In the first nine months of 2022, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first nine months of 2022. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

48 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.
49 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

Figure 9-11 PJM/NYISO credits for coordinated congestion management (flowgates): January 2021 through September 2022[50]

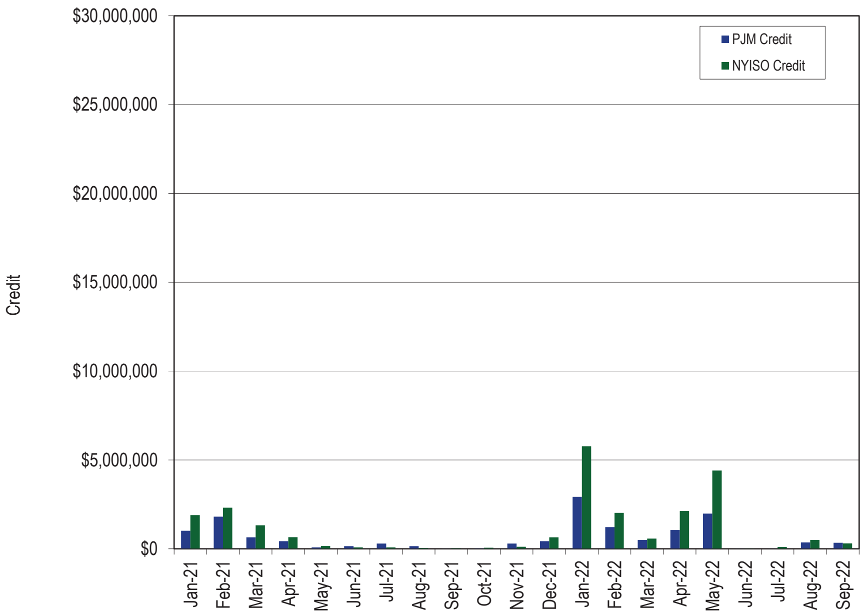


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real time to manage constraints.[51] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make

50 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
51 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In the first nine months of 2022, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-12 shows the PAR credits for coordinated congestion management between PJM and NYISO.

Figure 9-12 PJM/NYISO credits for coordinated congestion management (PARs): January 2021 through September 2022[52]



52 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and TVA Joint Reliability Coordination Agreement (JRCA)[53]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in the first nine months of 2022.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[54]

On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to include a CMP under Article 14 of the JOA.[55] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[56] PJM and DEP requested an effective date of July 22, 2019, for the

53 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.
54 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.
55 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc*. Docket No. ER10-713-000 (February 2, 2010).
56 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).

filed revisions. On July 2, 2019, the Commission issued a letter order accepting the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[57]

PJM and VACAR South Reliability Coordination Agreement[58]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in the first nine months of 2022.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) was a combination of agreements among the entities in the VACAR Subregion including Dominion.[59] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The VRSA was terminated on October 1, 2022. The agreement required that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).[60] Dominion was the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA was not a public agreement. PJM was not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[61]

There were issues with the VRSA. PJM implemented reserve market changes on October 1, 2022. These changes included the consolidation of synchronized reserves tier 1 and tier 2 and the reserve must offer requirement. With these changes, it would not be possible for Dominion to hold reserves to meet its obligations under the VRSA without failing the must offer requirement in PJM. Under the reserve market changes, it would not be possible for Dominion to meet both the VRSA and the PJM reserve rules. The Market Monitor recommended 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. The Market Monitor recommended 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.[62] On October 1, 2022, the VRSA was terminated.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[63]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first nine months of 2022.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[64]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first nine months of 2022.

57 FERC Docket No. ER19-1905-000.
58 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.
59 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.
60 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.
61 See PJM. "Manual 13: Emergency Operations," Rev. 85 (October 1, 2022).
62 See the *2022 Quarterly State of the Market Report for PJM: January through September*, Section 10: Ancillary Services, "VACAR Reserve Sharing Agreement" for more information on issues identified with the VACAR Reserve Sharing Agreement.
63 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <https://www.pjm.com/directory/merged-tariffs/rs43.pdf>.
64 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher was two in the first nine months of 2021 and one in the first nine months of 2022.[65] The number of different flowgates for which PJM declared a TLR 3a or higher was one in the first nine months of 2021, and one in the first nine months of 2022. The total MWh of transactions curtailed was zero in the first nine months of 2021 and 299 MWh in the first nine months of 2022.

The number of MISO issued TLRs of level 3a or higher decreased from 56 in the first nine months of 2021 to 43 in the first nine months of 2022. The number of different flowgates for which MISO declared a TLR 3a was 16 in the first nine months of 2021, and 15 in the first nine months of 2022. The total MWh of transaction curtailments decreased by 85.4 percent from 60,726 MWh in the first nine months of 2021 to 8,879 MWh in the first nine months of 2022.

The number of NYISO issued TLRs of level 3a or higher increased from one in the first nine months of 2021 to 23 in the first nine months of 2022. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in the first nine months of 2021, and three in the first nine months of 2022. The total MWh of transaction curtailments increased by 37,049.0 percent from 390 MWh in the first nine months of 2021, to 144,881 MWh in the first nine months of 2022.

65 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2020 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

Table 9-38 PJM, MISO, and NYISO TLR procedures: January through September, 2022[66]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-22	0	8	12	0	2	3	0	3,012	108,718
Feb-22	0	6	5	0	2	3	0	327	20,120
Mar-22	0	7	1	0	2	1	0	644	2,493
Apr-22	0	3	1	0	2	1	0	1,928	1,712
May-22	0	2	3	0	1	1	0	282	11,838
Jun-22	1	5	0	1	5	0	299	219	0
Jul-22	0	1	0	0	1	0	0	615	0
Aug-22	0	2	0	0	2	0	0	950	0
Sep-22	0	9	1	0	5	1	0	902	0
Total	1	43	23	1	15	3	299	8,879	144,881

Table 9-39 Number of TLRs by TLR level by reliability coordinator: January through September, 2022[67]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2022	MISO	15	5	0	15	8	0	43
	NYIS	23	0	0	0	0	0	23
	ONT	4	0	0	0	0	0	4
	PJM	0	1	0	0	0	0	1
	SOCO	5	9	0	0	0	0	14
	SWPP	16	21	8	12	28	0	85
	TVA	27	34	0	22	34	0	117
	VACS	0	0	0	0	0	0	0
Total		90	70	8	49	70	0	287

Up To Congestion Transactions

The original purpose, in 2000, of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the day-ahead energy market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the real-time energy market.[68]

66 The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.
67 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.
68 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required to pay uplift charges from their introduction in 2010 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[69] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[70]

Up to congestion transaction volumes decreased following the allocation of uplift charges to UTCs effective November 1, 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 52.8 percent, from 495,001 MWh per day in the 12 month period prior to the allocation of uplift charges (November 1, 2019, through October 31, 2020), to 233,632 MWh per day for the most recent 12 month period (October 1, 2021 through September 30, 2022). While the volume of UTCs has increased in recent months, the volume of UTCs remains well below the levels prior to the allocation of uplift charges.

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 number of up to congestion bids cleared in the day-ahead energy market increased by 6.1 percent, from 13,206 bids per day in the first nine months of 2021 to 14,016 bids per day in the first nine months of 2022. The average volume of up to congestion bids submitted in the day-ahead energy market increased by 89.3 percent, from 465,669 MWh per day in the first nine months of 2021, to 881,500 MWh 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.

69 172 FERC ¶ 61,046 (2020).
70 See the *2022 Quarterly State of the Market Report for PJM: January through September*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through September 2022

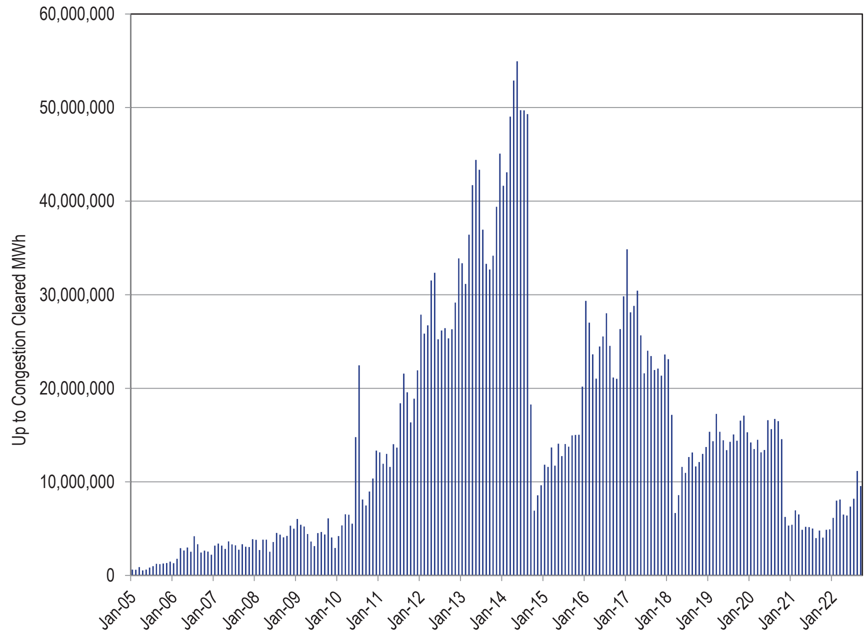


Table 9-40 Monthly volume of cleared and submitted up to congestion bids: January 2021 through September 2022

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-21	2,282,816	1,938,192	276,618	10,688,893	15,186,519	78,521	88,947	15,555	607,025	790,048
Feb-21	2,560,448	1,732,756	251,312	11,403,148	15,947,664	79,571	91,052	12,982	641,265	824,870
Mar-21	2,517,187	947,439	117,398	14,674,083	18,256,107	78,177	50,618	9,589	669,293	807,677
Apr-21	2,221,212	551,805	181,710	12,376,262	15,330,989	67,575	32,831	6,639	636,750	743,795
May-21	1,702,148	715,117	134,953	12,828,933	15,381,151	74,896	38,718	7,785	744,269	865,668
Jun-21	1,138,201	520,848	73,906	11,088,523	12,821,478	65,649	45,860	4,682	699,115	815,306
Jul-21	1,323,256	446,832	110,578	10,310,647	12,191,312	72,501	35,621	6,342	660,329	774,793
Aug-21	1,055,652	582,455	130,397	8,306,869	10,075,373	60,909	41,367	8,814	526,547	637,637
Sep-21	1,159,276	609,099	129,904	10,038,727	11,937,005	85,382	68,429	11,435	653,886	819,132
Oct-21	1,153,755	594,054	168,020	9,789,125	11,704,954	86,346	59,591	11,364	639,219	796,520
Nov-21	1,297,142	391,021	149,499	11,674,525	13,512,187	94,652	45,987	8,529	648,210	797,378
Dec-21	1,001,841	1,186,616	140,597	11,886,753	14,215,807	63,041	75,829	5,645	659,803	804,318
Jan-22	2,202,600	3,227,026	340,408	15,650,585	21,420,619	96,598	149,612	14,586	723,140	983,936
Feb-22	1,722,657	3,131,256	435,011	15,800,392	21,089,315	91,078	159,021	20,491	705,112	975,702
Mar-22	4,533,781	2,091,884	566,832	18,728,804	25,921,300	127,118	139,469	19,080	729,625	1,015,292
Apr-22	3,643,833	1,846,211	680,033	20,758,140	26,928,216	125,219	78,307	11,426	750,929	965,881
May-22	3,114,660	1,387,494	386,182	20,640,018	25,528,353	89,155	70,065	13,656	777,016	949,892
Jun-22	2,500,572	1,696,529	561,051	17,974,611	22,732,764	93,944	85,186	10,413	750,248	939,791
Jul-22	3,282,550	1,827,083	751,584	20,515,964	26,377,181	123,558	113,628	21,662	983,254	1,242,102
Aug-22	3,503,673	2,674,684	1,672,114	28,195,238	36,045,709	180,383	120,951	24,972	1,268,015	1,594,321
Sep-22	5,049,466	3,491,630	1,876,871	24,187,990	34,605,956	233,423	116,138	30,529	1,236,193	1,616,283
TOTAL	1,728,584,518	1,477,951,999	188,396,043	6,405,331,494	9,800,264,053	50,388,592	37,777,378	4,804,025	260,592,457	353,562,452

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-21	505,184	926,449	85,441	3,896,822	5,413,896	32,026	41,610	4,835	327,824	406,295
Feb-21	665,309	998,094	144,146	5,150,556	6,958,106	38,384	56,952	6,752	362,064	464,152
Mar-21	591,031	618,699	63,162	5,247,981	6,520,873	30,026	36,699	6,398	333,759	406,882
Apr-21	564,781	177,129	72,851	4,059,957	4,874,718	25,343	20,672	3,991	306,151	356,157
May-21	442,299	181,378	46,319	4,519,932	5,189,928	30,276	21,686	4,028	379,282	435,272
Jun-21	335,834	299,253	33,954	4,488,181	5,157,223	27,490	31,522	3,063	385,387	447,462
Jul-21	338,862	275,306	67,024	4,335,957	5,017,149	28,909	24,474	4,047	368,403	425,833
Aug-21	324,030	352,755	60,145	3,255,200	3,992,130	23,440	24,760	3,957	271,448	323,605
Sep-21	397,314	351,372	53,102	3,992,336	4,794,124	27,907	33,791	4,810	272,943	339,451
Oct-21	327,648	278,394	52,358	3,375,067	4,033,467	26,731	25,513	4,845	251,090	308,179
Nov-21	400,829	133,871	58,953	4,280,984	4,874,637	35,315	25,029	3,725	288,976	353,045
Dec-21	319,191	433,602	67,637	4,111,751	4,932,180	22,912	41,869	2,334	307,385	374,500
Jan-22	646,722	767,142	117,381	4,620,298	6,151,542	36,367	43,966	5,426	270,206	355,965
Feb-22	691,238	1,223,319	158,192	5,929,560	8,002,309	36,599	70,794	8,868	308,327	424,588
Mar-22	1,329,615	780,044	201,988	5,802,984	8,114,631	35,389	70,114	7,272	274,549	387,324
Apr-22	725,227	350,854	119,726	5,305,536	6,501,343	34,010	31,635	3,574	247,502	316,721
May-22	639,846	382,771	142,568	5,245,037	6,410,221	27,860	26,912	6,371	265,029	326,172
Jun-22	669,243	624,991	186,867	5,872,139	7,353,240	33,262	37,959	4,774	298,574	374,569
Jul-22	765,389	695,229	310,774	6,419,096	8,190,488	42,766	44,961	9,846	366,582	464,155
Aug-22	753,371	1,048,871	924,161	8,438,635	11,165,039	58,186	51,088	10,690	442,817	562,781
Sep-22	1,308,969	836,935	445,823	6,954,810	9,546,538	94,683	48,744	8,853	461,842	614,122
TOTAL	558,938,706	478,777,792	56,665,810	1,842,482,003	2,936,864,310	19,410,267	14,788,453	1,790,361	101,799,203	137,788,284

In the first nine months of 2022, the cleared MW volume of up to congestion transactions was comprised of 10.5 percent imports, 9.4 percent exports, 3.7 percent wheeling transactions and 76.4 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.[71] The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 105.4 percent, from net profits of $15.5 million in 2014, to a net loss of $839,891 in 2021. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour fell by 92.2 percent, from 1,898 hours in 2014 to 148 hours in 2021.

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.

71 *See* Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities.[72] For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing

72 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first nine months of 2022, of the 992.3 GWh of gross scheduled transactions between PJM and IESO, 943.0 GWh (95.0 percent) wheeled through MISO (Table 9-25). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[73]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[74] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2022. Table 9-41 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 24.0 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.02 per MWh. In 22.2 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $62.72 when the price difference was greater than $20.00, and $102.33 when the price difference was greater than -$20.00.

73 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

74 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

Table 9-41 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2022

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	14.6%	$62.72
$10 to $20	11.2%	$14.35
$5 to $10	10.5%	$7.29
$0 to $5	24.0%	$2.02
$0 to -$5	19.3%	$1.93
-$5 to -$10	6.8%	$7.19
-$10 to -$20	5.9%	$14.20
< -$20	7.6%	$102.33

Table 9-42 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 35.3 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 44.4 percent in the 135 minute ahead IT SCED results.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2022

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	17.0%	$66.21	11.6%	$48.82	9.4%	$46.08	22.5%	$76.64
$10 to $20	11.9%	$14.37	11.3%	$14.24	10.1%	$14.30	12.0%	$14.46
$5 to $10	10.1%	$7.24	11.3%	$7.27	9.6%	$7.27	9.6%	$7.37
$0 to $5	25.7%	$1.96	26.3%	$1.97	21.9%	$2.01	18.7%	$2.14
$0 to -$5	18.7%	$1.77	20.0%	$1.85	22.6%	$2.05	16.6%	$2.11
-$5 to -$10	5.5%	$7.15	6.6%	$7.16	8.8%	$7.18	7.1%	$7.20
-$10 to -$20	4.7%	$14.17	5.5%	$14.25	7.9%	$14.18	6.0%	$14.17
< -$20	6.4%	$107.30	7.4%	$105.68	9.7%	$94.48	7.4%	$98.88

In 29.9 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $76.64 when the price difference was greater than $20.00, and $98.88 when the price difference was greater than -$20.00.

Table 9-43 and Table 9-44 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-43 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through September, 2022

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	38.3%	20.1%	14.6%	22.3%	18.7%	22.2%	22.6%	22.1%	21.6%	22.5%
	$10 to $20	8.8%	7.9%	10.9%	11.0%	14.4%	13.7%	13.2%	10.8%	16.8%	12.0%
	$5 to $10	6.6%	8.2%	11.9%	9.5%	11.6%	10.2%	9.8%	8.0%	10.6%	9.6%
	$0 to $5	11.2%	21.2%	29.5%	19.5%	17.7%	16.6%	18.1%	15.0%	20.1%	18.7%
	$0 to -$5	10.6%	23.6%	20.7%	16.9%	14.2%	14.6%	16.5%	17.2%	15.8%	16.6%
	-$5 to -$10	5.3%	6.9%	5.5%	8.0%	9.1%	7.4%	7.1%	8.5%	6.5%	7.1%
	-$10 to -$20	5.3%	4.4%	3.4%	6.6%	6.6%	7.1%	6.7%	9.4%	4.5%	6.0%
	< -$20	13.8%	7.8%	3.5%	6.2%	7.8%	8.2%	6.1%	9.0%	4.1%	7.4%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	8.9%	3.8%	3.0%	11.5%	9.6%	12.0%	14.0%	13.9%	7.3%	9.4%
	$10 to $20	6.4%	4.2%	5.6%	10.6%	12.8%	13.2%	12.6%	11.0%	14.1%	10.1%
	$5 to $10	6.7%	5.7%	9.6%	10.1%	11.3%	11.4%	10.9%	8.5%	12.3%	9.6%
	$0 to $5	16.1%	25.9%	29.2%	22.5%	22.7%	21.2%	20.1%	16.4%	23.5%	21.9%
	$0 to -$5	19.1%	33.7%	32.5%	21.1%	19.6%	17.7%	18.6%	20.2%	22.1%	22.6%
	-$5 to -$10	9.8%	9.5%	9.7%	9.1%	8.9%	7.7%	7.8%	9.4%	7.4%	8.8%
	-$10 to -$20	9.6%	6.0%	5.6%	8.2%	8.1%	7.8%	8.7%	10.1%	6.7%	7.9%
	< -$20	23.4%	11.1%	4.9%	7.0%	7.0%	9.1%	7.4%	10.5%	6.6%	9.7%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	13.1%	5.4%	3.7%	13.0%	12.0%	11.9%	16.7%	18.8%	9.5%	11.6%
	$10 to $20	7.4%	4.9%	6.3%	13.2%	13.6%	14.6%	13.1%	11.9%	16.2%	11.3%
	$5 to $10	8.0%	6.1%	11.8%	11.4%	13.1%	13.6%	12.0%	10.5%	15.0%	11.3%
	$0 to $5	17.8%	32.8%	36.4%	26.3%	26.5%	25.6%	24.1%	19.5%	28.7%	26.3%
	$0 to -$5	19.2%	29.8%	27.6%	18.4%	18.7%	15.3%	16.2%	18.2%	17.1%	20.0%
	-$5 to -$10	8.1%	7.0%	6.3%	7.3%	6.0%	6.2%	6.2%	7.2%	4.9%	6.6%
	-$10 to -$20	7.8%	4.4%	3.8%	5.7%	4.7%	5.7%	6.5%	6.8%	4.0%	5.5%
	< -$20	18.5%	9.7%	4.1%	4.8%	5.5%	7.1%	5.3%	7.2%	4.7%	7.4%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	16.1%	6.1%	6.6%	18.9%	19.2%	19.4%	23.4%	25.6%	17.0%	17.0%
	$10 to $20	7.1%	4.2%	9.8%	14.6%	13.8%	14.6%	13.5%	12.6%	16.3%	11.9%
	$5 to $10	7.4%	6.3%	11.3%	9.8%	10.6%	12.3%	11.1%	8.4%	13.7%	10.1%
	$0 to $5	18.1%	33.5%	35.5%	25.8%	27.5%	24.9%	22.3%	18.8%	25.5%	25.7%
	$0 to -$5	19.2%	29.7%	25.4%	17.1%	16.3%	13.6%	14.8%	16.6%	16.6%	18.7%
	-$5 to -$10	8.0%	6.6%	5.1%	5.0%	4.8%	4.9%	5.4%	5.8%	3.5%	5.5%
	-$10 to -$20	6.7%	4.3%	3.0%	4.9%	3.7%	4.6%	5.2%	6.2%	3.4%	4.7%
	< -$20	17.4%	9.2%	3.4%	3.9%	4.0%	5.6%	4.2%	6.0%	3.9%	6.4%

Table 9-44 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through September, 2022

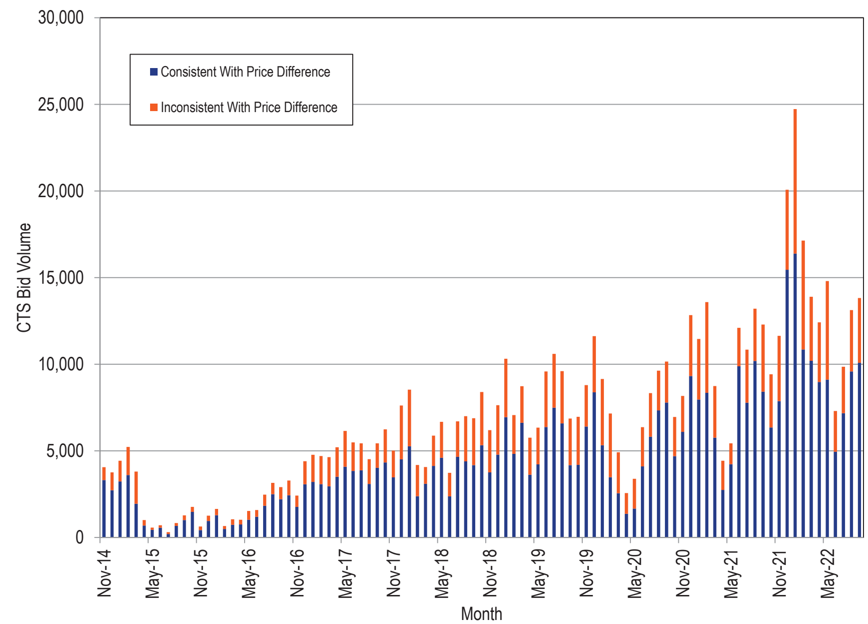
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$114.85	$102.03	$83.03	$50.25	$83.91	$51.73	$54.50	$69.74	$57.24	$76.64
	$10 to $20	$14.12	$14.19	$13.69	$14.65	$14.66	$14.68	$14.83	$14.27	$14.62	$14.46
	$5 to $10	$7.37	$7.11	$7.26	$7.27	$7.39	$7.40	$7.45	$7.51	$7.53	$7.37
	$0 to $5	$2.38	$2.17	$2.10	$2.09	$2.26	$2.12	$2.12	$2.05	$2.09	$2.14
	$0 to -$5	$2.33	$2.06	$1.93	$2.14	$2.23	$2.14	$2.08	$2.13	$2.10	$2.11
	-$5 to -$10	$7.23	$7.12	$7.15	$7.10	$7.10	$7.32	$7.16	$7.48	$7.09	$7.20
	-$10 to -$20	$14.47	$13.78	$13.91	$14.36	$14.31	$13.78	$14.11	$14.48	$13.94	$14.17
	< -$20	$185.57	$121.82	$59.21	$66.17	$57.16	$96.81	$40.96	$84.28	$48.14	$98.88
Interval	**Range of Price Differences**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**YTD Avg**
~ 45 Minutes Prior to Real-Time	> $20	$49.37	$56.88	$46.18	$38.14	$57.20	$48.69	$44.80	$44.72	$34.97	$46.08
	$10 to $20	$14.46	$13.98	$13.73	$14.08	$14.26	$14.48	$14.46	$14.25	$14.47	$14.30
	$5 to $10	$7.20	$6.99	$7.26	$7.32	$7.20	$7.24	$7.28	$7.31	$7.44	$7.27
	$0 to $5	$2.18	$1.90	$1.75	$2.01	$2.24	$2.17	$1.98	$2.02	$1.99	$2.01
	$0 to -$5	$2.21	$1.92	$1.79	$2.18	$2.30	$2.05	$2.01	$2.18	$2.04	$2.05
	-$5 to -$10	$7.31	$7.02	$7.34	$7.20	$7.02	$7.28	$7.09	$7.31	$7.01	$7.18
	-$10 to -$20	$14.31	$13.88	$13.81	$14.08	$14.12	$14.23	$14.23	$14.61	$14.01	$14.18
	< -$20	$148.75	$109.61	$56.59	$54.33	$46.70	$109.79	$43.23	$82.11	$53.74	$94.48
Interval	**Range of Price Differences**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**YTD Avg**
~ 90 Minutes Prior to Real-Time	> $20	$61.85	$61.18	$53.22	$39.18	$41.10	$44.78	$44.79	$57.24	$40.17	$48.82
	$10 to $20	$14.61	$14.38	$13.19	$14.36	$14.22	$14.47	$14.30	$14.36	$14.00	$14.24
	$5 to $10	$7.08	$6.98	$7.29	$7.24	$7.25	$7.27	$7.29	$7.46	$7.33	$7.27
	$0 to $5	$2.00	$1.69	$1.78	$2.03	$2.16	$2.16	$2.03	$2.01	$2.02	$1.97
	$0 to -$5	$2.00	$1.77	$1.74	$1.94	$1.85	$1.82	$1.83	$1.92	$1.81	$1.85
	-$5 to -$10	$7.11	$7.11	$7.21	$7.11	$7.13	$7.25	$7.28	$7.17	$7.06	$7.16
	-$10 to -$20	$14.65	$13.95	$13.81	$14.15	$14.34	$14.23	$14.19	$14.42	$14.13	$14.25
	< -$20	$164.24	$118.11	$59.55	$60.94	$55.84	$118.83	$43.81	$99.36	$51.25	$105.68
Interval	**Range of Price Differences**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**YTD Avg**
~ 135 Minutes Prior to Real-Time	> $20	$79.06	$74.20	$87.03	$58.28	$51.53	$62.50	$68.70	$80.44	$46.93	$66.21
	$10 to $20	$14.59	$14.23	$13.91	$14.43	$14.48	$14.38	$14.37	$14.61	$14.26	$14.37
	$5 to $10	$7.10	$6.92	$7.25	$7.18	$7.19	$7.27	$7.33	$7.32	$7.39	$7.24
	$0 to $5	$2.00	$1.74	$1.81	$2.15	$2.10	$2.02	$2.06	$1.93	$1.93	$1.96
	$0 to -$5	$2.00	$1.66	$1.63	$1.87	$1.73	$1.81	$1.79	$1.82	$1.78	$1.77
	-$5 to -$10	$7.16	$7.04	$7.09	$7.14	$7.08	$7.29	$7.29	$7.24	$6.98	$7.15
	-$10 to -$20	$14.08	$13.96	$13.87	$14.03	$13.91	$14.56	$14.33	$14.46	$14.06	$14.17
	< -$20	$165.90	$118.50	$60.38	$62.11	$57.33	$119.03	$42.70	$79.72	$51.56	$107.30

The NYISO uses PJM's IT SCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through September 30, 2022, 649,065 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 203,880 (31.4 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 31.4 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 68.6 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-14 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-14 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through September 30, 2022



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2022. Table 9-45 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 21.7 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.12. In 24.7 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $52.47 when the price difference was greater than $20.00, and $62.82 when the price difference was greater than -$20.00.

Table 9-45 Differences between forecast and actual PJM/MISO interface prices: January through September, 2022

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	18.4%	$52.47
$10 to $20	11.8%	$14.48
$5 to $10	10.5%	$7.27
$0 to $5	21.7%	$2.12
$0 to -$5	18.0%	$2.01
-$5 to -$10	7.1%	$7.22
-$10 to -$20	6.1%	$14.17
< -$20	6.4%	$62.82

Table 9-46 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 34.9 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 40.4 percent in the 135 minute ahead IT SCED results.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January through September, 2022

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	22.6%	$65.23	16.7%	$44.90	15.3%	$45.40	21.4%	$55.98
$10 to $20	11.3%	$14.48	12.1%	$14.43	11.2%	$14.59	11.5%	$14.48
$5 to $10	10.3%	$7.27	11.2%	$7.22	9.8%	$7.31	9.9%	$7.29
$0 to $5	23.0%	$2.04	23.3%	$2.09	20.1%	$2.11	18.1%	$2.22
$0 to -$5	17.4%	$1.91	18.4%	$1.99	19.8%	$2.10	16.9%	$2.14
-$5 to -$10	5.9%	$7.19	6.8%	$7.22	8.7%	$7.25	7.7%	$7.25
-$10 to -$20	4.7%	$14.11	5.6%	$14.10	7.4%	$14.21	7.3%	$14.16
< -$20	4.8%	$65.74	6.0%	$65.74	7.8%	$60.68	7.4%	$57.30

In 28.7 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $55.98 when the price difference was greater than $20.00, and $57.30 when the price difference was greater than -$20.00.

Table 9-47 and Table 9-48 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-47 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through September, 2022

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	9.2%	4.7%	9.9%	25.7%	30.4%	30.4%	28.8%	28.0%	24.1%	21.4%
	$10 to $20	13.0%	6.7%	11.0%	12.4%	14.1%	9.5%	10.8%	9.8%	15.5%	11.5%
	$5 to $10	14.4%	10.8%	12.9%	10.9%	8.5%	7.8%	7.7%	6.0%	10.2%	9.9%
	$0 to $5	21.9%	27.7%	24.2%	12.9%	14.4%	14.7%	17.8%	13.3%	16.2%	18.1%
	$0 to -$5	19.8%	29.4%	22.7%	12.9%	11.0%	12.7%	14.0%	16.7%	13.4%	16.9%
	-$5 to -$10	9.5%	8.8%	8.0%	8.1%	6.6%	7.6%	6.5%	8.0%	6.3%	7.7%
	-$10 to -$20	6.3%	5.9%	6.4%	9.4%	7.2%	7.1%	7.0%	8.9%	7.3%	7.3%
	< -$20	5.8%	6.0%	4.9%	7.7%	7.9%	10.3%	7.4%	9.3%	7.0%	7.4%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	3.6%	2.2%	6.0%	18.2%	21.7%	21.9%	21.6%	23.4%	18.4%	15.3%
	$10 to $20	7.3%	3.9%	8.8%	14.1%	14.7%	11.9%	13.4%	11.2%	15.5%	11.2%
	$5 to $10	11.6%	7.2%	11.6%	10.5%	8.8%	9.5%	9.3%	7.5%	11.7%	9.8%
	$0 to $5	24.7%	29.1%	25.3%	15.8%	16.8%	18.1%	18.6%	14.5%	18.1%	20.1%
	$0 to -$5	24.8%	36.1%	26.3%	13.9%	15.1%	15.1%	14.8%	17.7%	15.2%	19.8%
	-$5 to -$10	12.3%	9.6%	10.2%	9.3%	8.0%	6.3%	7.5%	7.6%	7.2%	8.7%
	-$10 to -$20	8.9%	5.4%	6.7%	9.5%	7.1%	6.7%	7.5%	8.7%	5.9%	7.4%
	< -$20	6.9%	6.4%	5.2%	8.5%	7.9%	10.5%	7.2%	9.3%	7.9%	7.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	4.1%	1.9%	6.4%	20.4%	22.5%	23.2%	22.4%	26.5%	21.6%	16.7%
	$10 to $20	7.7%	3.7%	8.4%	15.2%	16.4%	13.7%	14.4%	12.4%	16.5%	12.1%
	$5 to $10	12.2%	8.1%	12.9%	12.8%	10.3%	10.5%	11.0%	9.8%	12.6%	11.2%
	$0 to $5	25.4%	35.5%	30.4%	17.1%	20.3%	21.1%	22.1%	17.5%	20.7%	23.3%
	$0 to -$5	26.9%	32.1%	24.0%	13.1%	14.0%	14.2%	13.6%	15.5%	13.5%	18.4%
	-$5 to -$10	10.6%	8.2%	8.0%	7.2%	5.5%	4.7%	5.9%	5.7%	5.2%	6.8%
	-$10 to -$20	6.8%	4.6%	5.5%	8.0%	5.2%	4.6%	5.3%	6.2%	4.0%	5.6%
	< -$20	6.2%	5.9%	4.4%	6.1%	5.8%	8.0%	5.3%	6.3%	5.9%	6.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	6.6%	3.2%	10.1%	27.2%	29.7%	29.5%	30.7%	33.9%	30.9%	22.6%
	$10 to $20	8.3%	3.8%	10.0%	13.8%	15.4%	12.9%	13.0%	11.3%	13.1%	11.3%
	$5 to $10	11.7%	7.3%	12.8%	12.9%	9.7%	9.8%	9.4%	7.6%	11.1%	10.3%
	$0 to $5	26.0%	35.6%	30.1%	17.6%	19.6%	22.0%	20.4%	16.8%	19.9%	23.0%
	$0 to -$5	26.3%	31.8%	22.8%	11.4%	12.6%	12.4%	13.1%	14.2%	12.7%	17.4%
	-$5 to -$10	8.9%	8.3%	6.5%	6.1%	4.9%	3.7%	4.9%	5.8%	4.0%	5.9%
	-$10 to -$20	6.5%	4.2%	4.5%	6.0%	3.9%	3.5%	4.3%	5.4%	3.7%	4.7%
	< -$20	5.7%	5.7%	3.3%	4.9%	4.2%	6.2%	4.1%	4.9%	4.5%	4.8%

Table 9-48 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through September, 2022

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$37.60	$32.35	$46.98	$54.25	$64.95	$67.76	$57.51	$62.60	$36.71	$55.98
	$10 to $20	$14.15	$14.37	$14.11	$14.47	$14.82	$14.50	$14.69	$14.53	$14.59	$14.48
	$5 to $10	$7.26	$7.10	$7.33	$7.39	$7.21	$7.23	$7.15	$7.28	$7.60	$7.29
	$0 to $5	$2.37	$2.15	$2.27	$2.46	$2.25	$2.08	$2.07	$2.08	$2.27	$2.22
	$0 to -$5	$2.18	$2.05	$2.12	$2.28	$2.23	$2.24	$2.03	$2.16	$2.11	$2.14
	-$5 to -$10	$7.20	$7.15	$7.13	$7.35	$7.23	$7.29	$7.29	$7.32	$7.32	$7.25
	-$10 to -$20	$13.98	$13.70	$13.74	$14.53	$14.47	$14.20	$14.24	$14.41	$13.83	$14.16
	< -$20	$66.38	$46.79	$44.64	$59.14	$57.16	$80.40	$45.76	$51.28	$51.93	$57.30

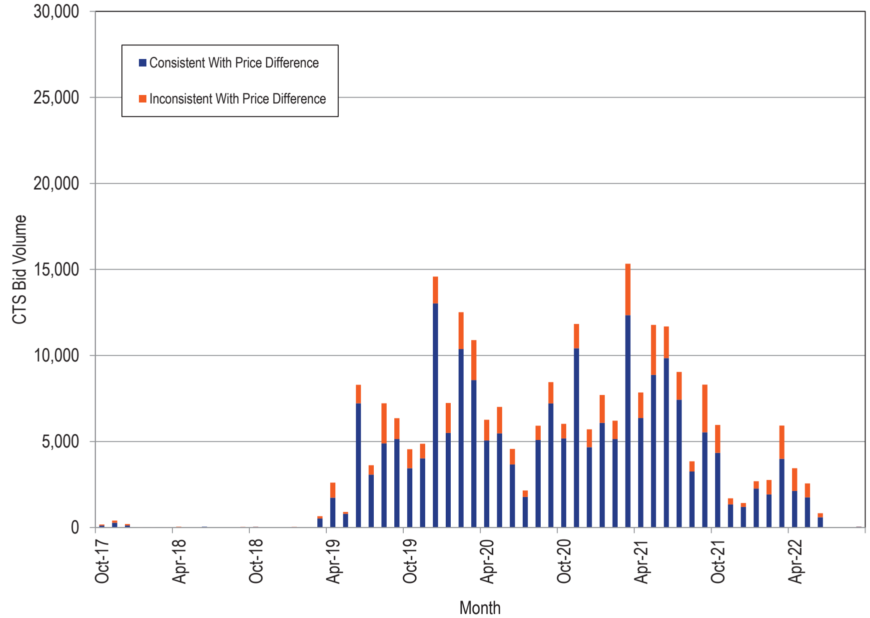
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$37.77	$29.33	$41.07	$41.81	$44.31	$62.42	$46.71	$45.76	$32.60	$45.40
	$10 to $20	$14.06	$14.08	$13.95	$14.54	$14.91	$14.69	$14.78	$14.71	$14.75	$14.59
	$5 to $10	$7.35	$6.86	$7.25	$7.34	$7.25	$7.26	$7.42	$7.49	$7.43	$7.31
	$0 to $5	$2.15	$1.92	$2.15	$2.43	$2.32	$2.09	$2.01	$1.94	$2.06	$2.11
	$0 to -$5	$2.22	$2.04	$1.93	$2.38	$2.24	$2.14	$2.05	$2.05	$2.02	$2.10
	-$5 to -$10	$7.16	$7.14	$7.18	$7.29	$7.42	$7.39	$7.22	$7.17	$7.37	$7.25
	-$10 to -$20	$13.88	$13.63	$14.27	$14.09	$14.66	$14.44	$14.40	$14.17	$14.29	$14.21
	< -$20	$64.97	$46.99	$46.97	$57.90	$62.73	$99.63	$47.73	$50.41	$50.27	$60.68

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$36.60	$28.88	$38.27	$43.46	$42.27	$54.02	$45.26	$50.72	$36.51	$44.90
	$10 to $20	$13.59	$14.14	$13.90	$14.34	$14.80	$14.43	$14.66	$14.31	$14.76	$14.43
	$5 to $10	$7.17	$6.91	$7.25	$7.29	$7.21	$7.14	$7.29	$7.23	$7.38	$7.22
	$0 to $5	$2.08	$1.80	$2.19	$2.29	$2.19	$2.16	$2.08	$1.97	$2.17	$2.09
	$0 to -$5	$2.05	$1.89	$1.95	$2.26	$2.00	$1.92	$1.94	$1.95	$2.09	$1.99
	-$5 to -$10	$7.14	$7.02	$7.19	$7.30	$7.30	$7.19	$7.32	$7.42	$7.20	$7.22
	-$10 to -$20	$13.79	$13.94	$13.96	$13.97	$14.43	$14.09	$14.49	$14.29	$13.98	$14.10
	< -$20	$67.08	$49.02	$47.74	$65.31	$67.95	$112.75	$50.82	$57.43	$51.10	$65.74

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$45.03	$32.40	$67.66	$60.97	$61.68	$76.67	$68.78	$75.23	$53.36	$65.23
	$10 to $20	$13.94	$13.75	$13.90	$14.46	$14.81	$14.47	$14.61	$14.83	$14.73	$14.48
	$5 to $10	$7.13	$6.86	$7.19	$7.31	$7.37	$7.30	$7.38	$7.29	$7.48	$7.27
	$0 to $5	$2.04	$1.84	$2.11	$2.25	$2.16	$1.98	$2.01	$1.98	$2.11	$2.04
	$0 to -$5	$2.03	$1.82	$1.93	$2.18	$1.84	$1.83	$1.80	$1.89	$1.91	$1.91
	-$5 to -$10	$6.97	$7.04	$7.03	$7.33	$7.26	$7.35	$7.46	$7.40	$7.09	$7.19
	-$10 to -$20	$13.92	$13.85	$14.07	$14.14	$14.16	$14.39	$14.02	$14.10	$14.51	$14.11
	< -$20	$66.24	$47.71	$49.35	$66.28	$68.98	$115.48	$51.18	$58.78	$48.48	$65.74

CTS transactions were evaluated for each interval. From October 3, 2017, through September 30, 2022, 252,454 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 50,402 (20.0 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 20.0 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 80.0 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-15 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-15 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences. In June 2022, MISO experienced software issues that prevented the submission and clearing of CTS transactions. The issue was resolved in August 2022. It is unclear why market participants have yet to resume scheduling CTS transactions at the MISO interface at the same levels prior to the software issue.

Figure 9-15 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through September 30, 2022



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-49 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in both January 2016 and February 2019.

Table 9-49 Monthly uncollected congestion charges: January 2010 through September 2022

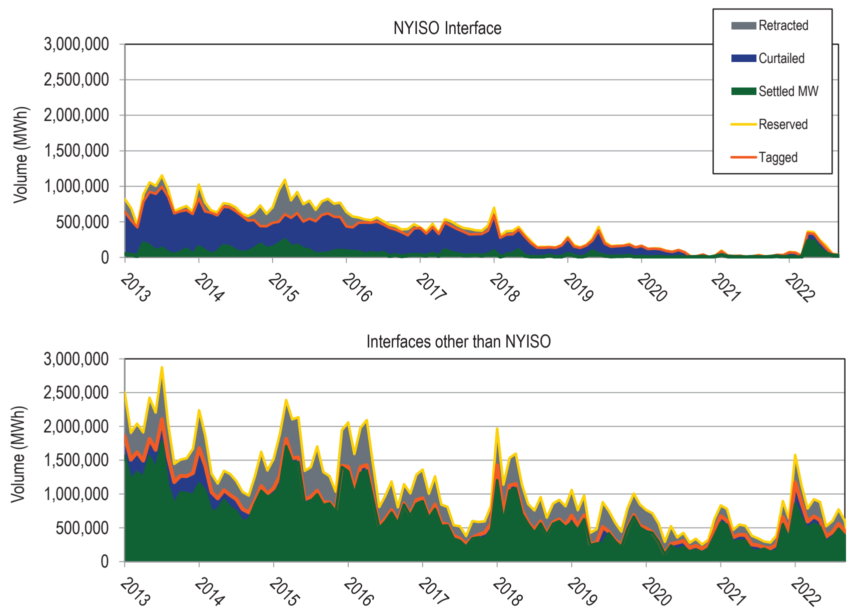
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)	$0	$0	$0

Spot Imports

Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through September 30, 2022. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-16 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.[75]

75 See the *2018 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

Figure 9-16 Spot import service use: January 2013 through September 2022



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point to point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[76] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point to point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, are dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is based on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 the sum of all external transactions were -3,000 MW (negative sign indicates net exporting),

76 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764. See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, order on reh'g, Order No. 764-A, 141 FERC ¶ 61231 (2012).

the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[77] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[78]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[79]

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.[80] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[81] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[82] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[83] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[84] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[85]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[86] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export… it is appropriate to allow MISO to assess the MVP

77 *Id.* at P 51.
78 See *Id.* at P 12.
79 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.
80 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
81 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
82 133 FERC ¶ 61,221; *order on reh'g*, 137 FERC ¶ 61,074 (2011).
83 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
84 *Id.* at 780.
85 *Id.* at 779.
86 156 FERC ¶ 61,034 (2016).

usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[87]

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-50 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2022 through 2040.[88] As shown in Table 9-4, there were 4,858.0 GWh of imports from MISO in the first nine months of 2022. At the 2022 MUR of $1.65 per MWh, PJM market participants paid $8.0 million towards the costs of MISO's multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-50 MISO projected multi value project usage rate: 2022 through 2041

Year	Total Indicative MVP Usage Rate ($/MWh)
2022	$1.65
2023	$1.77
2024	$1.75
2025	$1.73
2026	$1.71
2027	$1.69
2028	$1.67
2029	$1.66
2030	$1.64
2031	$1.62
2032	$1.60
2033	$1.58
2034	$1.57
2035	$1.55
2036	$1.53
2037	$1.51
2038	$1.50
2039	$1.48
2040	$1.46
2041	$1.45

87 *Id.* at P 55.
88 See MISO, "Schedule 26A Indicative Annual Charges," (July 20, 2021) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

Ancillary Service Markets

FERC defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve—synchronized reserve service; and operating reserve—supplemental reserve service.[1] PJM provides scheduling, system control and dispatch, and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formula rates.

PJM implemented significant reserve market changes on October 1, 2022. This *State of the Market Report for PJM: January through September* is written based on the market rules that applied during the first nine months of 2022, recognizing that the rules changed on October 1. Those rule changes will be addressed in the State of the Market Report for 2022. The present tense is used when describing the rules in place during the first nine months of 2022 to reflect the pre October 1, 2022, perspective of the report.

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

Table 10-1 The tier 2 synchronized reserve market results were competitive

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

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require 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.

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

Table 10-2 The day-ahead scheduling reserve market results were competitive

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

- The DASR market 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

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the real-time energy market.

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.

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

Table 10-3 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.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

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 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.

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

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.[4] This is the synchronized energy premium price.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is 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.[5]

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

4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 122 (Oct. 1, 2022).

5 NERC (June 2, 2020) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

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.[6]

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.[7]
- **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.

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.[8]

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

7 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 121 (Jul. 7, 2022).

8 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.

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.[9] 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.

9 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 121 (Jul. 7, 2022).

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.

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.[10] 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

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

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.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[11]

In the first 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.[12] All capacity costs of generators should be incorporated in the capacity market. The nonmarket 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.[13] 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

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

12 OATT Schedule 2.

13 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.

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.[14] 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.

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.[15] 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.

Ancillary Services Costs per MWh of Load

Table 10-4 shows PJM ancillary services costs for the first nine months of 1999 through 2022, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh.[16] The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

14 OATT Attachment O § 4.7.2 (Primary Frequency Response).
15 *Id.*; see also "PJM Manual 12: Balancing Operations, Rev. 47 (Oct. 1, 2022). § 3.6 (Primary Frequency Response).
16 The total prices in this table are a load-weighted average system price per MWh by category, even if each category is not charged on that basis. These totals are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM.

Table 10-4 History of ancillary services costs per MWh of load: January through September, 1999 through 2022[17 18]

Year (Jan-Sep)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.16	$0.22	$0.25	$0.00	$0.63
2000	$0.33	$0.29	$0.31	$0.00	$0.93
2001	$0.55	$0.70	$0.22	$0.00	$1.47
2002	$0.42	$0.82	$0.19	$0.00	$1.43
2003	$0.53	$1.01	$0.23	$0.13	$1.90
2004	$0.50	$0.99	$0.25	$0.14	$1.88
2005	$0.78	$0.73	$0.26	$0.11	$1.88
2006	$0.55	$0.74	$0.28	$0.07	$1.64
2007	$0.65	$0.72	$0.27	$0.06	$1.70
2008	$0.78	$0.44	$0.33	$0.07	$1.62
2009	$0.36	$0.34	$0.36	$0.04	$1.10
2010	$0.38	$0.36	$0.36	$0.06	$1.16
2011	$0.36	$0.37	$0.38	$0.09	$1.20
2012	$0.23	$0.42	$0.44	$0.03	$1.12
2013	$0.27	$0.42	$0.67	$0.03	$1.39
2014	$0.36	$0.43	$0.40	$0.14	$1.33
2015	$0.25	$0.42	$0.36	$0.12	$1.15
2016	$0.11	$0.43	$0.37	$0.05	$0.96
2017	$0.13	$0.48	$0.42	$0.06	$1.09
2018	$0.20	$0.47	$0.40	$0.06	$1.13
2019	$0.11	$0.47	$0.42	$0.04	$1.04
2020	$0.10	$0.48	$0.46	$0.02	$1.06
2021	$0.15	$0.50	$0.46	$0.05	$1.16
2022	$0.36	$0.44	$0.49	$0.13	$1.42

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

17 Note: The totals in Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
18 Reactive totals include FERC approved rates for reactive capability.

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.

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.

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.[19])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[20] FERC rejected.[21])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[22])

19 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
20 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
21 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
22 *Id.*

- 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.[23])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[24])
- 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.)
- 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.)

23 *Id.*
24 *Id.*

- 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.[25] 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.[26] (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The design of the PJM Regulation Market is significantly flawed.[27] 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

25 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.
26 *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>.
27 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).

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 FERC on October 17, 2017.[28] 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.[29] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[30]

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.[31]

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.[32] 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

28 18 CFR § 385.211.
29 162 FERC ¶ 61,295 (2018).
30 170 FERC ¶ 61,259 (2020).
31 See FERC Docket No. EL19-58.
32 See FERC Docket No. EL19-58.

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 annual *2022 State of the Market Report for PJM*.

Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the ACE to zero if it was zero or positive before the event or to its pre-event level if it was negative at the start of the event. The Contingency Reserve Restoration period is the time required to restore contingency (primary) reserves to a level greater than or equal to the largest single contingency after the end of the Contingency Event Recovery Period. NERC standards set the Contingency Event Recovery Period as 15 minutes and Contingency Reserve Restoration Period as 90 minutes.[33] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[34] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

33 See PJM. "PJM Manual 12: Balancing Operations," Rev. 47 (Oct. 1, 2022) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes." While this cited attachment only references restoring synchronized reserves, PJM Manuals 10 & 13 make it clear that primary reserves serve as PJM's contingency reserve.

34 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 42 (Oct. 1, 2021).

Market Structure

Demand

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the largest single contingency (also known as the most severe single contingency, or MSSC).[35] PJM requires primary reserves in the amount of 150 percent of the largest single contingency with at least 100 percent of the requirement made up of synchronized reserves.[36] In the first nine months of 2022, the average synchronized reserve requirement was 1,675.4 MW in the MAD Subzone and 1,676.2 MW in the RTO Zone. The synchronized reserve requirement is calculated for every real-time market dispatch solution. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

The primary reserve market requirement is set equal to 150 percent of the largest single contingency for each market solution, ASO, IT SCED, and RT SCED. The largest single contingency is usually the output of the largest generating unit to which PJM adds 190 MW. In cases where temporary switching conditions create the risk that a single fault could remove several generators, PJM will define the largest single contingency as the sum of the output of those generators.[37]

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[38] Such additional reserves are committed as part of the hourly (ASO) and five minute (RT SCED) processes. In the first nine months of 2022, the average primary reserve requirement for the RTO Zone was 2,419.3 MW. The average primary reserve requirement in the MAD Subzone was 2,418.2 MW. These averages include the hours when PJM raised the requirements.

35 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," September 25, 2018. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.

36 See PJM. "PJM Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 85 (Oct. 1, 2022).

37 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).

38 See *id.*

The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5).

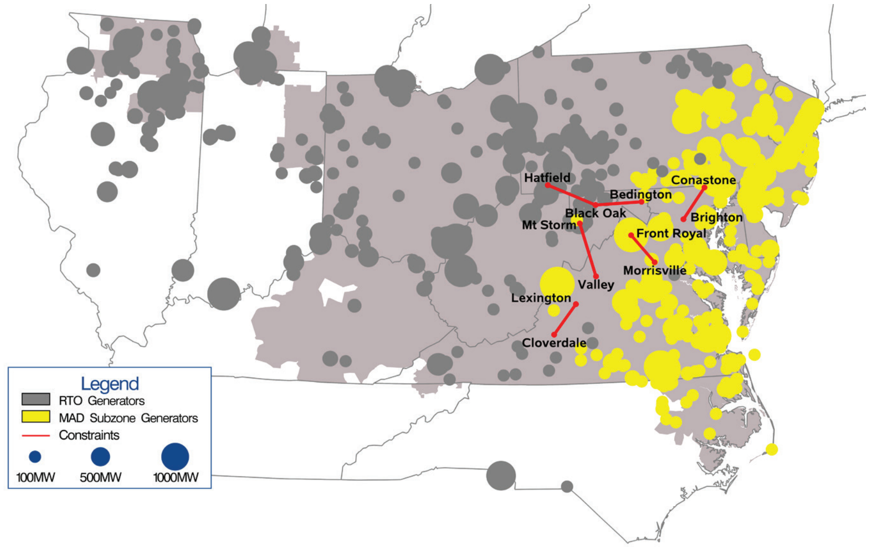
Table 10-5 Temporary adjustments to primary and synchronized reserve: January through September, 2022

From	To	Number of Hours	Amount of Adjustment
1-Jan-22	9-Feb-22	936	Primary Reserve (64 MW), Synchronized Reserve (43 MW)
21-Feb-22	25-Feb-22	103	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
29-Mar-22	31-Mar-22	54	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
10-Apr-22	15-Apr-22	122	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
16-May-22	20-Jun-22	848	Primary Reserve (38 MW), Synchronized Reserve (26 MW)
28-Jun-22	30-Jun-22	42	Primary Reserve (1,189 MW), Synchronized Reserve (792 MW)
26-Jul-22	26-Jul-22	1	Primary Reserve (76 MW), Synchronized Reserve (50 MW)
6-Sep-22	10-Sep-22	96	Primary Reserve (137 MW), Synchronized Reserve (92 MW)

Transmission constraints can limit the deliverability of reserves within the RTO, requiring the definition of a subzone. In the first nine months of 2022, PJM defined a single subzone, the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[39] Figure 10-1 is a map of constraints and major generation sources. The constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The RTO Zone into MAD Subzone constraints reflect limits on the transmission line capacity that separate the RTO Zone and MAD Subzone. If, in the case of a spinning event, the current economic dispatch plus the current synchronized market dispatch would overload the constraint, then all additional synchronized reserve MW must be cleared from the unconstrained side of the constraints. When this occurs, the synchronized reserve prices between the RTO Zone and the MAD Subzone will diverge. In practice, PJM has always maintained only the MAD Subzone but for any market solution several distinct constraining paths are analyzed and the most limiting one becomes the definition for that solution.

39 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.2 Creation of New Reserve Subzones, Rev. 122 (Oct. 1, 2022).

Figure 10-1 PJM RTO Zone and MAD Subzone map of constraints and generation sources



The most limiting transmission constraint for power flow from the RTO Zone into the MAD Subzone since August 2017 has been the AP South Interface. The most frequent constraint in the first nine months of 2022 was Bedington-Black Oak, then Brighton-Conastone, and Cloverdale-Lexington.

Supply

The demand for primary reserve is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and nonsynchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. After the synchronized reserve requirement is satisfied, the remainder of primary reserves is from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 contributes to meeting PJM's primary reserve requirement and PJM's synchronized reserve requirement. In the MAD Subzone, an average of 693.6 MW of tier 1 was available in the first nine months 2022 (Table 10-6).[40] Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement or reduced the need for tier 2 synchronized reserve to self-scheduled reserves in 4.6 percent of dispatch solutions in the first nine months of 2022. In the RTO Zone, an average of 1,531.4 MW of tier 1 was available, fully satisfying the synchronized reserve requirement in 36.0 percent of real-time dispatch solutions (Table 10-7).

Regardless of online/offline state, all nonemergency generation capacity resources must submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (14:15 the day prior to the operating day). Resources listed as available for tier 2 synchronized reserve without a synchronized reserve offer will have their offer price automatically set to $0.00. Offer MW and other non-cost offer parameters can be changed during the operating day. Owners who opt in for intraday updates may change their offer price up to 65 minutes before the hour. While not exempt from making an offer, units that cannot reliably provide synchronized reserve may offer zero MW of tier 2 reserve. Certain unit types, including nuclear, wind, solar, and energy storage resources, are expected to offer zero MW.[41]

Offer prices for synchronized reserve are capped at $7.50 per MWh plus marginal cost, as defined in PJM Manual 15.

In the clearing process, after tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2.

In the first nine months of 2022, in the MAD Subzone, there was an average of 1,289.8 MW of eligible nonsynchronized reserve supply available to meet the average demand for primary reserve (Table 10-6). In the RTO Zone, an average of 1,633.2 MW of nonsynchronized reserve supply was available to meet the average demand of 2,436.9 MW (Table 10-7).

40 ASO, Ancillary Services Optimizer. This is the hour-ahead market software that optimizes ancillary services with energy. ASO schedules hourly the Tier 2 Synchronized Reserve, Regulation, and Nonsynchronized Reserves.

41 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 121 (Jul. 7, 2022).

Table 10-6 provides the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2021 through September 2022.

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2021 through September 2022

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2021	Jan	835.6	250.6	1,331.5	2,417.7
2021	Feb	976.5	216.5	1,240.2	2,433.2
2021	Mar	883.9	214.2	1,163.0	2,261.1
2021	Apr	686.7	316.6	1,275.6	2,279.0
2021	May	653.0	247.2	1,141.5	2,041.7
2021	Jun	835.6	203.6	1,266.7	2,305.9
2021	Jul	890.3	205.1	1,260.6	2,356.0
2021	Aug	915.6	221.9	1,270.8	2,408.4
2021	Sep	906.3	236.1	1,203.9	2,346.3
2021	Oct	592.9	433.7	1,210.1	2,236.7
2021	Nov	569.4	413.2	1,330.9	2,313.4
2021	Dec	742.3	339.1	1,336.9	2,418.3
2021	Average	787.2	276.9	1,252.8	2,316.9
2022	Jan	849.0	267.1	1,364.5	2,480.6
2022	Feb	898.3	87.8	1,221.7	2,207.7
2022	Mar	700.2	135.8	1,159.7	1,995.7
2022	Apr	567.6	253.3	1,339.4	2,160.4
2022	May	594.9	270.4	1,267.8	2,133.1
2022	Jun	654.5	294.7	1,445.8	2,395.0
2022	Jul	601.7	258.5	1,333.5	2,193.8
2022	Aug	631.1	287.4	1,372.3	2,290.8
2022	Sep	761.6	244.4	1,096.8	2,102.8
2022	Average	693.6	234.5	1,289.8	2,217.9

Table 10-7 shows the average dispatch solution reserves, by type of reserve, satisfying the primary reserve requirement in the RTO Zone in January 2021 through September 2022.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2021 through September 2022

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2021	Jan	1,758.2	508.6	1,515.0	3,781.9
2021	Feb	1,851.4	599.4	1,510.5	3,961.2
2021	Mar	1,702.0	596.0	1,455.9	3,753.9
2021	Apr	1,308.5	753.2	1,594.0	3,655.8
2021	May	1,375.8	787.4	1,566.5	3,729.7
2021	Jun	1,696.9	618.2	1,579.9	3,895.0
2021	Jul	1,675.5	664.2	1,587.4	3,927.1
2021	Aug	1,770.6	709.1	1,598.7	4,078.4
2021	Sep	1,777.4	657.1	1,491.3	3,925.8
2021	Oct	1,109.3	1,067.4	1,694.8	3,871.5
2021	Nov	1,160.3	1,029.8	1,804.2	3,994.2
2021	Dec	1,622.7	639.8	1,560.9	3,823.3
2021	Average	1,561.7	722.9	1,581.6	3,866.2
2022	Jan	1,711.1	495.0	1,521.4	3,727.5
2022	Feb	1,949.3	358.3	1,406.6	3,714.2
2022	Mar	1,513.4	590.1	1,515.9	3,619.5
2022	Apr	1,152.3	774.7	1,733.7	3,660.8
2022	May	1,471.1	802.7	1,698.4	3,972.2
2022	Jun	1,532.6	876.0	1,871.1	4,279.7
2022	Jul	1,464.7	783.4	1,707.2	3,955.3
2022	Aug	1,428.9	940.8	1,837.4	4,207.2
2022	Sep	1,589.2	710.2	1,388.0	3,687.4
2022	Average	1,531.4	706.4	1,633.2	3,871.0

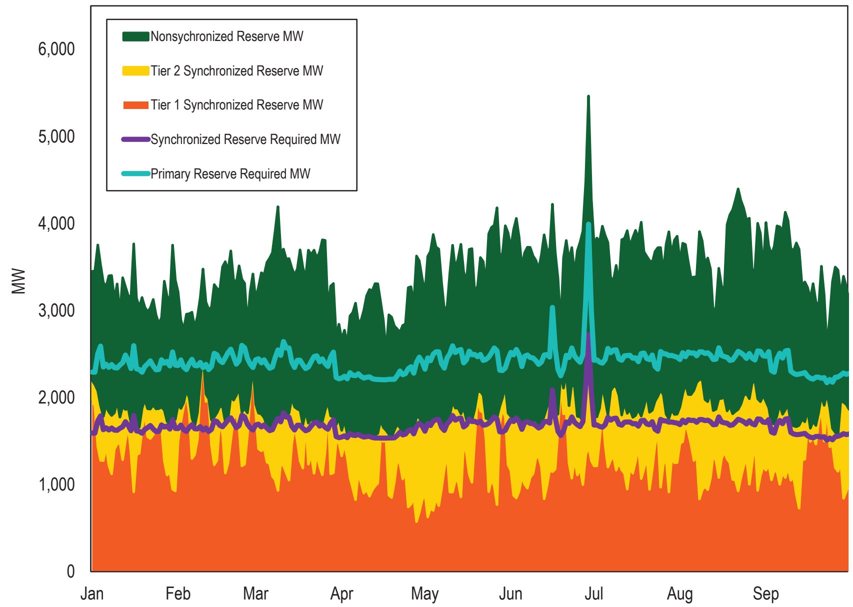
Supply and Demand

The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).

Inflexible tier 2 synchronized reserve is committed by the ASO. If there is enough estimated tier 1 MW available to satisfy the synchronized reserve requirement, then no inflexible tier 2 synchronized reserve MW is committed. If the sum of the tier 1 MW and the ASO-committed inflexible tier 2 MW does not meet the synchronized reserve requirement, then the RT SCED will commit available flexible tier 2 synchronized reserve. If there is an excess of synchronized reserve, then the RT SCED may decommit previously committed flexible synchronized reserves. The primary reserve requirement is met by economically assigning inflexible synchronized reserves, flexible synchronized reserves, and nonsynchronized reserves.

Figure 10-2 shows how the daily average market solutions satisfy the primary reserve requirement for the RTO Zone. PJM temporarily increased the primary and synchronized reserve requirements in June. The details are in Table 10-5.

Figure 10-2 RTO reserve zone primary reserve MW by source (Daily Averages): January through September, 2022



In the first nine months of 2022, tier 1 synchronized reserve was the primary source of synchronized reserves, but tier 1 and tier 2 were both needed to meet the synchronized reserve requirement.

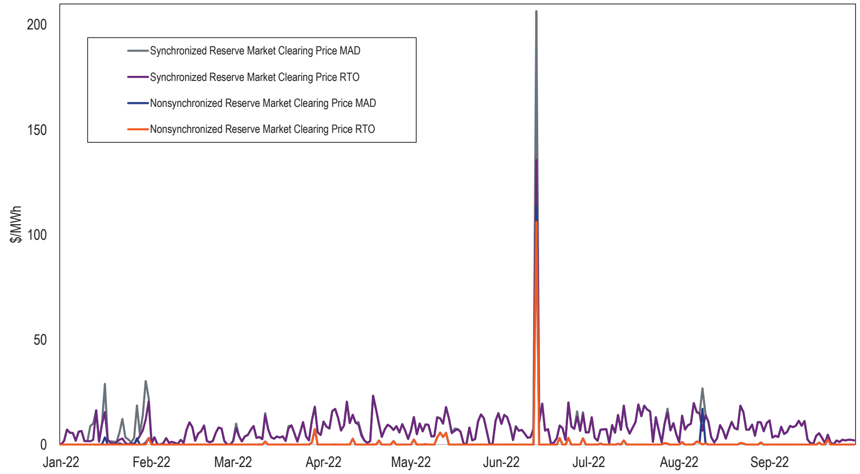
Price and Cost

The price of primary reserves results from the demand curve for primary reserves and the supply of primary reserves. The demand curve is modeled in each of the primary reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for primary reserves has two steps, with an $850 penalty factor for primary reserve levels from 0 MW to a MW amount equal to 150 percent of the MSSC, and a $300 penalty factor for primary reserve levels from 150 percent of MSSC, to 150 percent of MSSC plus 190 MW.

Figure 10-3 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first nine months of 2022. The MAD SRMCP and RTO SRMCP prices diverged in 1,046 five-minute intervals, 0.6 percent of the total 183,708 intervals, in the first nine months of 2022.

There was a significant increase in the price of reserves on June 13, 2022 as a result of shortage pricing (Figure 10-3). On June 13, the RTO primary reserve was short for 35 intervals and the RTO synchronized reserve was short for 11 intervals, all concurrent with the primary reserve shortage. The MAD primary reserve was short for 35 intervals and the MAD synchronized reserve was short for eight intervals, all concurrent with the primary reserve shortage.

Figure 10-3 Daily average market clearing prices ($/MWh) for synchronized reserve and nonsynchronized reserve: January through September, 2022



Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. The tier 1 synchronized reserve for a unit is estimated as the lesser of the available 10 minute ramp or the difference between the economic dispatch point and the synchronized reserve maximum output, which by default is equal to its economic maximum. Resource owners may request a lower synchronized reserve maximum if a physical limitation exists.[42] Tier 1 resources are identified by the market solution. Tier 1 synchronized reserves have an incremental cost of zero. Tier 1 synchronized reserves are paid under two circumstances. Tier 1 reserves are paid when they respond to a synchronized reserve event. Tier 1 reserves are paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price is above $0.

42 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (Oct. 1, 2022).

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve and any response to a spinning event will be credited at the synchronized energy premium price, except during intervals in which the non-synchronized reserve market clearing price was above $0, in which case response was credited at the synchronized reserve market clearing price.

Introduced in 2014, DGP (Degree of Generator Performance) was a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. In the first nine months of 2022, the available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and submitted synchronized reserve ramp rate, adjusted by its DGP. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current DGP.[43] DGP violates the basic PJM principle that generation owners are solely responsible for their own offers. In addition, DGP is a crude estimate of ramp rates and does not account for the actual discontinuities along unit offer curves. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units.[44] These unit types are credited the synchronized energy premium price, like any other responding unit, if they respond to a spinning event, but will not, however, be paid as tier 1 resources when the nonsynchronized reserve market clearing price goes above $0 outside of spinning events. There is a review process for resources excluded by default from the tier 1 estimate that request to be included.[45] PJM also excludes units, regardless of type, that it deems unreliable as tier 1, though it allows those resources to provide tier 2 synchronized reserve.

Table 10-8 provides tier 1 synchronized reserve supplied by resource and fuel type in the first nine months of 2022, including all tier 1 credited for responding to synchronized reserve events and paid when the nonsynchronized reserve price exceeded $0 per MW.

Table 10-8 Supply of tier 1 synchronized reserve by resource and fuel type: January through September, 2022

Unit/Fuel Type	Percent by MW	Percent by Credits
Combined Cycle	46.3%	44.4%
Steam - Coal	19.5%	24.5%
CT - Natural Gas	12.8%	10.6%
Solar	9.9%	8.3%
Wind	5.4%	5.8%
Steam - Natural Gas	2.6%	2.6%
Hydro - Run of River	1.4%	1.8%
Steam - Other	1.3%	0.8%
RICE - Natural Gas	0.4%	0.4%
CT - Oil	0.1%	0.2%
Hydro - Pumped Storage	0.1%	0.2%
DSR	0.1%	0.2%
Nuclear	0.1%	0.2%
RICE - Other	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
RICE - Oil	0.0%	0.0%

In the first nine months of 2022, the SCED market solutions estimated that tier 1 MW from an average of 60 units could have an average of 1,531.4 MW of ramp available in a spinning event. For the 14 spinning events in the first nine months of 2022, PJM paid a total of 3,734.0 MW of tier 1 response across 37 intervals. Settlements included units like wind, solar, nuclear, and

43 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," (May 6, 2015). <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx>

44 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 121 (July 7, 2022).

45 See *id.*

demand response which are not a part of the estimated tier 1 in the SCED market solutions.

The actual response is the sum of the products contributing to total ACE increase from the time the event is initiated to 10 minutes after the event is initiated. Total increase in ACE is a sum not only of tier 1 response, but also of tier 2 response, RegA and RegD actual response (RegD response is sometimes a MW increase and sometimes a MW decrease), and changes to net imports/exports across PJM's boundaries (sometimes an increase and sometimes a decrease in MW).

In the RTO Reserve Zone, the average estimated tier 1 synchronized reserve was 1,531.4 MW (Table 10-7). In 36.0 percent of dispatch solutions, the estimated tier 1 synchronized reserve was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve plus self-scheduled tier 2.

In the first nine months of 2022, the average estimated tier 1 synchronized reserve within the MAD Subzone was 693.6 MW (Table 10-6). In 4.6 percent of dispatch solutions the estimated tier 1 synchronized reserve available within the MAD Subzone plus the self-scheduled tier 2 in MAD was greater than the synchronized reserve requirement and no tier 2 market needed to be cleared.

Demand

There is no required amount of tier 1 synchronized reserve. The estimated tier 1 MW contribute to meeting the demand for synchronized and primary reserve.

The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0, even when the cost of tier 1 is positive because the nonsynchronized reserve market clearing price is above $0. As a result, the optimization cannot and does not minimize the total cost of primary reserves. The MMU recommends that tier 1 synchronized reserve not be paid when the nonsynchronized reserve market clearing price is above $0. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

Supply and Demand

When solving for the synchronized reserve requirement the market solution first estimates the amount of tier 1 available from the energy dispatch. If the requirement is not filled by tier 1, it then commits tier 2 beginning with all self-scheduled synchronized reserve.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve.

Tier 1 Synchronized Reserve Payments

Tier 1 synchronized reserve is awarded credits under two circumstances. The first is in response to a spinning event. The second is during intervals outside of a spinning event during which the non-synchronized reserve market clearing price is above $0 and the unit is included in the estimated tier 1 MW.

In response to a spinning event, all resources (except scheduled tier 2 resources) are paid for increasing output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP during intervals in which the non-synchronized reserve market clearing price is $0.[46] This is the synchronized energy premium price. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between one minute before and one minute after the event is declared. Generator outputs are measured and reported to PJM every four seconds via SCADA. Total response credited to a resource is capped at 110 percent of estimated capability. As a result, spinning event response involves more MW response than the original estimate of tier 1. Many resources that are not included in PJM's estimate of tier 1 nevertheless respond to spinning events and in accordance with the PJM Tariff are paid the synchronized energy premium price. This can include incidental response from nuclear units or steam turbines running at maximum output. Tier 1 synchronized reserve that

46 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 121 (Jul. 7, 2022).

is part of the estimate when there is no spinning event is also credited for its full estimated MW whenever the nonsynchronized reserve market clearing price is above $0.

In the event that the nonsynchronized reserve market clearing price is above $0 and there is a spinning event, estimated tier 1 is credited with the lesser of its actual response or its estimated capability times the SRMCP. Tier 1 synchronized reserve not part of the estimate is credited the SRMCP times its actual response.[47] In the first nine months of 2022, the nonsynchronized reserve market clearing price was above $0 in 609 five-minute intervals (0.8 percent of the total 78,612).

In the first nine months of 2022, tier 1 synchronized reserve spinning event response credits of $246,309 were paid for 14 spinning events averaging 10.1 minutes. Table 10-9 shows the number of spinning events each month, the credits paid for tier 1 response, the number of MWh credited, and the actual response in MW.

47 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.2.1 Synchronized Reserve Clearing Price Credit, Rev. 87 (Jul. 27, 2022).

Table 10-9 Tier 1 synchronized reserve event response credits: January 2021 through September 2022

Year	Month	Number of Spinning Events	Total Tier 1 Spinning Event Credits	Total Tier 1 Spinning Event Credited (MWh)	Total Tier 1 Spinning Response from Event Start to Event End (MW)
2021	Jan	1	$6,796	135.9	1,165.0
2021	Feb	0	NA	NA	NA
2021	Mar	1	$15,729	314.6	1,715.8
2021	Apr	2	$40,442	808.8	4,677.8
2021	May	1	$21,822	436.4	2,618.6
2021	Jun	2	$16,275	325.5	3,183.2
2021	Jul	2	$16,026	320.5	2,999.1
2021	Aug	2	$46,487	929.7	4,666.3
2021	Sep	1	$126,863	279.2	2,094.2
2021	Oct	2	$27,267	545.3	3,800.4
2021	Nov	3	$50,939	1,018.8	6,024.5
2021	Dec	1	$7,188	143.8	1,232.3
2021	Total	18	$375,832	5,258.6	34,177.2
2022	Jan	1	$9,160	183.2	1,221.3
2022	Feb	0	NA	NA	NA
2022	Mar	1	$10,600	212.0	1,817.1
2022	Apr	3	$82,685	1,653.7	6,277.2
2022	May	4	$76,641	1,532.8	8,854.1
2022	Jun	2	$26,620	532.4	3,982.1
2022	Jul	1	$14,594	291.9	2,189.1
2022	Aug	0	NA	NA	NA
2022	Sep	2	$26,010	520.2	5,202.0
2022	Total	14	$246,309	4,926.2	29,542.9

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves is also zero. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. The PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 is compensated at the synchronized energy premium price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-10). In the first nine months of 2022, the nonsynchronized reserve market clearing price was above $0.00 in 0.8 percent of all intervals, or 609 of the total 78,612. This is a decrease from the first nine months of 2021, in which 2.1 percent of intervals had a market clearing price above $0.00, or 1,631 of the total 78,601. For those intervals, estimated tier 1 synchronized reserve was paid $6,178,605 for an average of 588.5 MW per interval of which all credits were for intervals outside of spinning events.

Table 10-10 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2021 through September 2022

Year	Month	Number of Intervals When NSRMCP > $0	Weighted Average SRMCP When NSRMCP > $0	Total Tier 1 MWh When NSRMCP > $0	Total Tier 1 Credits When NSRMCP > $0	Average Tier 1 MWh Monthly When NSRMCP > $0
2021	Jan	31	$36.20	3,625.7	$75,337	604.3
2021	Feb	160	$20.31	19,953.0	$326,372	739.0
2021	Mar	60	$95.30	7,775.0	$724,173	518.3
2021	Apr	196	$10.34	24,978.1	$203,281	531.4
2021	May	644	$12.75	74,895.9	$797,736	720.2
2021	Jun	199	$12.62	25,628.0	$255,053	596.0
2021	Jul	95	$27.79	13,751.7	$325,970	528.9
2021	Aug	123	$56.79	15,098.7	$758,395	503.3
2021	Sep	123	$26.95	18,665.3	$454,768	777.7
2021	Oct	865	$20.82	113,069.8	$1,828,570	796.3
2021	Nov	490	$33.16	54,585.5	$1,527,555	941.1
2021	Dec	22	$69.35	2,487.4	$87,728	414.6
2021	Total	3,008	$32.10	374,514.1	$7,364,937	639.3
2022	Jan	17	$147.27	2,039.3	$200,464	407.9
2022	Feb	0	NA	NA	NA	NA
2022	Mar	30	$116.28	3,696.5	$329,826	528.1
2022	Apr	56	$51.67	6,702.1	$247,448	515.5
2022	May	240	$33.95	29,644.6	$767,809	871.9
2022	Jun	120	$372.44	11,604.3	$4,062,541	828.9
2022	Jul	29	$47.00	3,581.9	$141,084	398.0
2022	Aug	81	$37.43	8,622.6	$272,513	538.9
2022	Sep	36	$37.48	5,570.0	$156,920	618.9
2022	Total	609	$105.44	71,461.3	$6,178,605	588.5

The additional payments to tier 1 synchronized reserves under the shortage pricing rule are a windfall. Table 10-11 shows the amount of windfall paid to tier 1 resources from January 2014 through September 2022.

Table 10-11 Windfall payments made to tier 1 resources: January 2014 through September 2022

Year	Windfall Payment
2014	$89,719,045
2015	$34,397,441
2016	$4,948,084
2017	$2,197,514
2018	$4,732,025
2019	$3,217,178
2020	$3,320,726
2021	$7,354,224
2022 (Jan-Sep)	$6,178,605
Total	$156,064,842

The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance; all estimated tier 1 receives the higher payment regardless of whether they provide any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In the first nine months of 2022, there were three spinning events of 10 minutes or longer. In those events, an average of 70.9 percent of the estimated tier 1 responded and 51.4 percent of tier 2 responded.

Tier 1 should have been compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation required that when a synchronized reserve event was called, all tier 1 response was paid the synchronized energy premium price. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

PJM's tier 1 compensation rules prior to the October 1 changes are presented in Table 10-12.

Table 10-12 Tier 1 compensation as implemented by PJM

Tier 1 Compensation by Type of Interval as Currently Implemented by PJM		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(estimated tier 1 MW, actual response MWi)

The MMU's recommended compensation rules for tier 1 MW prior to the October 1 changes are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Currently Recommended by MMU		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement cannot be met by tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve is provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve is also provided by demand resources that have offered to reduce load in the event of a synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event. Tier 2 resources have a must offer requirement. Some tier 2 resources are scheduled by the ASO 60 minutes before the operating hour and are committed to provide synchronized reserve for the entire hour. Tier 2 resources are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources are paid the clearing price (SRMCP).

Synchronized reserve resources can be flexible or inflexible. Inflexible resources are defined as those resources that require an hourly commitment due to minimum run times or staffing constraints. Examples of inflexible reserves are synchronous condensers operating in condensing mode, resources with an economic minimum (EcoMin) equal to economic maximum (EcoMax), offline CTs and hydro that can operate in the condense mode, and demand resources. Inflexible synchronized reserve resources are committed for a full hour by the hour ahead ASO market solution. Inflexible resources require a 30 minute notification time and cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the tier 2 requirement. The actual requirement is determined by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units. Flexible resources are already online for energy, require no notification time, and can be automatically dispatched.

During the operating hour, RT SCED can dispatch additional tier 2 resources. RT SCED can redispatch online tier 1 generating resources as tier 2 synchronized reserve to meet the synchronized and primary reserve requirements within the operational hour. Resources that are redispatched as tier 2 within the hour are paid the SRMCP plus any lost opportunity costs that exceed the SRMCP.

Market Structure

Supply

PJM has a must offer tier 2 synchronized reserve requirement. All nonemergency generating resources are required to submit tier 2 synchronized reserve offers. All online, nonemergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve in accordance with their ability. Generating resources must be able to provide at least 0.1 MW of tier 2 reserve in order to make offers in the tier 2 synchronized reserve market. Unit types that cannot reliably provide synchronized reserve, including nuclear, wind, solar, and energy storage resources, are expected to offer zero MW of tier 2 synchronized reserve. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all offline emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[48]

In the first nine months of 2022, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 5,478.1 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 35,043.1 MW of tier 2 synchronized reserve offers (Figure 10-6).

The supply of tier 2 synchronized reserve offered in the first nine months of 2022 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in the first nine months of 2022 was from demand resources followed by CTs running on natural gas (Table 10-14). Although demand resources are limited to providing no more than 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in some hours demand resources make up considerably more than 33 percent of the cleared tier 2 MW. Demand resources often offer at a price of $0, do not incur an LOC, and clear even when the price is $0. As a result, their share of credits in the synchronized reserve market is less than their share of cleared MW.

Table 10-14 Supply of Tier 2 Synchronized Reserve by Resource Type and Fuel Type: January through September, 2022

Resource/Fuel Type	Percent by MW	Percent by Credits
DSR	34.1%	17.3%
CT - Natural Gas	27.3%	31.1%
Combined Cycle	17.5%	28.8%
CT - Oil	9.3%	11.0%
Hydro - Run of River	8.2%	7.0%
Steam - Coal	1.8%	2.7%
Hydro - Pumped Storage	1.5%	1.6%
RICE - Natural Gas	0.2%	0.3%
Steam - Natural Gas	0.1%	0.2%
Steam - Other	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Oil	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the largest single contingency (also known as the most severe single contingency, or MSSC) as the first step, and extended by a 190 MW second step.[49] There are two circumstances in which PJM may alter the base portion of the synchronized reserve requirement from its 100 percent of the largest contingency value. Reserve requirements may be increased during a temporary switching condition when transmission outages or configuration problems cause several generation resources to be subject to a single contingency. When PJM operators anticipate periods of high load, they may bring on additional units to account for increased operational

48 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 121 (June 1, 2022).

49 See the *2022 Quarterly State of the Market Report: January through September*, Section 3: Energy Market, at "Operating Reserve Demand Curves".

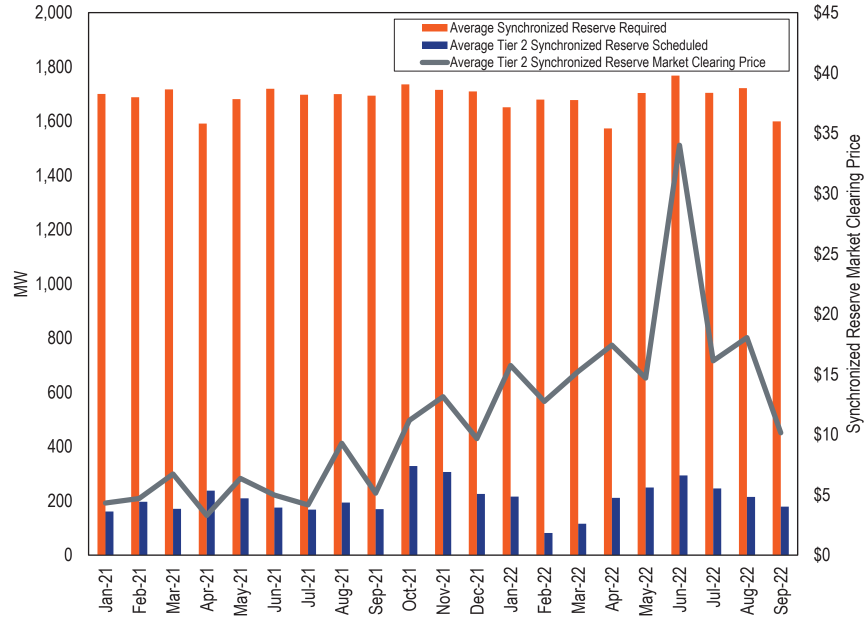
uncertainty in meeting load. When a Hot Weather Alert, Cold Weather Alert or an emergency procedure has been issued for the operating day, operators may increase the synchronized reserve requirement up to the full amount of the additional MW brought on line.[50]

In the first nine months of 2022, the average synchronized reserve requirement was 1,676.2 MW in the RTO Zone and 1,675.4 in the MAD Subzone. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone scheduled and identified an average of 552.0 MW of tier 2 synchronized reserves in the first nine months of 2022. Of this, an average of 545.4 MW was scheduled hourly.

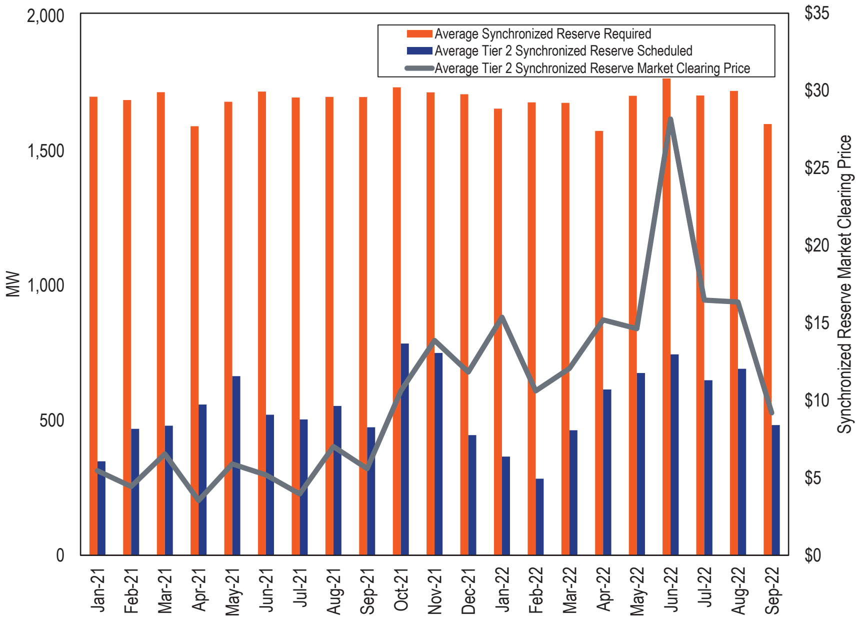
Figure 10-4 and Figure 10-5 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self-scheduled) from January 2021 through September 2022, for the MAD Reserve Subzone and the RTO Reserve Zone. In the first nine months of 2021, there were 19 intervals of synchronized reserve shortage and 12 spinning events of which four were longer than 10 minutes. In the first nine months of 2022, there were 30 intervals of synchronized reserve shortage in the dispatch solution and 14 spinning events of which three were longer than 10 minutes. There were 33 intervals of synchronized reserve shortage in the pricing solution. Shortage pricing was used for synchronized reserve during 11 intervals on June 13 alone, causing a higher average price for June.

Figure 10-4 MAD monthly average tier 2 synchronized reserve scheduled MW: January 2021 through September 2022



50 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).

Figure 10-5 RTO monthly average tier 2 synchronized reserve scheduled MW: January 2021 through September 2022



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first nine months of 2022 was 4437, which is defined as highly concentrated. In 68.7 percent of all cleared pricing intervals the maximum market share was greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared pricing intervals of the RTO Zone Tier 2 Synchronized Reserve Market in the first nine months of 2022 was 2898, which is defined as highly concentrated. In 31.6 percent of cleared intervals there was a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 1.0 percent of all tier 2 synchronized reserve in the first nine months of 2022. In the RTO Zone, flexible synchronized reserve was 1.3 percent of all tier 2 synchronized reserve MW in the first nine months of 2022.

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

Offers

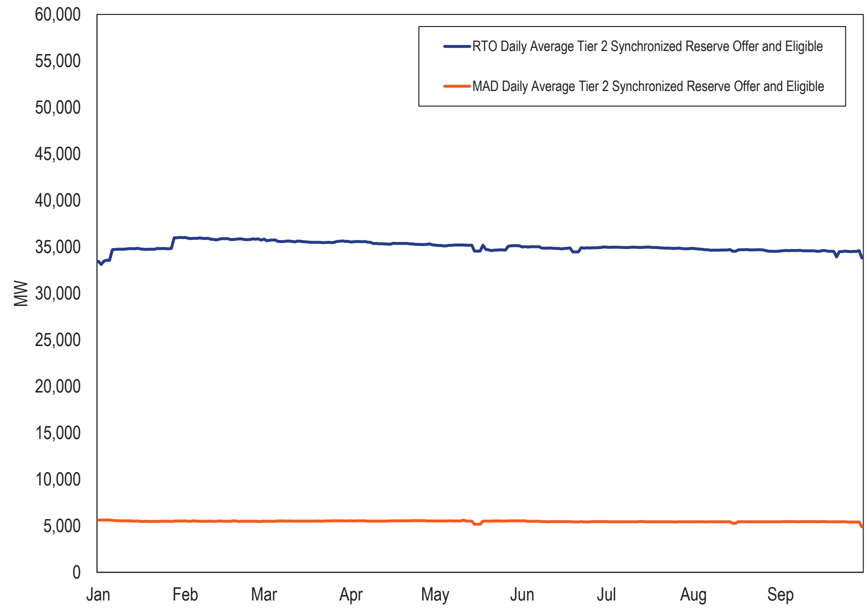
Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include, when relevant, a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The tier 2 synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate must be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate is greater than the economic ramp rate it must be justified by the submission of actual data from previous synchronized reserve events.[51] All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity is limited to the economic maximum. PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to zero MW. Certain defined resource types are not required to offer tier 2 because they cannot reliably provide synchronized reserve. These include: nuclear, wind, solar, landfill gas and energy storage resources.[52]

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

Figure 10-6 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[53] The tier 2 synchronized reserve market is not cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-6). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status, and grid conditions including constraints. However, resource operators can mark their units as unavailable for an hour or block of hours without having to provide a reason. In the first nine months of 2022, synchronized reserve offers averaged 35,043.6 MW in the RTO Zone and 5,478.1 MW in the MAD Subzone.

Figure 10-6 Tier 2 synchronized reserve hourly offer and eligible volume (MW):[54] January through September, 2022



Although tier 2 synchronized reserve has a must offer requirement, there are a large number of hours when many units make themselves unavailable for tier 2 synchronized reserve.

The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer to 0 MW.[55] This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

53 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 121 (July 7, 2022). ("Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserves in Markets Gateway…").

54 These values less than what was previously reported.

55 PJM adopted a new business rule in the third quarter of 2017 to enforce compliance with the tier 2 must offer requirement. PJM entered a zero dollar offer price for all units with a must offer obligation for tier 2 synchronized reserves.

Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes by the LPC market solution for the RTO Reserve Zone and the MAD Subzone. The tier 2 synchronized reserve market price is determined not only by the offer price of each cleared MW of tier 2, but additionally by the net cost of jointly optimizing the dispatch of energy and synchronized reserve. For each MW assigned, the clearing engines determine a product substitution price, i.e. the marginal cost of replacing the reserve MW with energy from other resources. The product substitution cost is a function of the LMPs of the MW of reserve, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the price is the sum of the offer price plus the product substitution cost of the marginal unit(s).[56] The number of marginal units by schedule type is shown in Table 10-15.

Table 10-15 Schedule used for LOC of marginal units in RTSCED Tier 2 Synchronized Reserve Market LOC calculation: January through September, 2022

Number of Marginal Units	Percent of Marginal Units with LOC Based on Cost Schedule	Percent of Marginal Units with LOC Based on Price Schedule
79,073	21.5%	78.5%

In the first nine months of 2022, the RTSCED cleared the RTO tier 2 synchronized reserve market in 63.8 percent of all dispatch solutions. In all other intervals there was enough tier 1 synchronized reserve to cover the synchronized reserve requirement. For intervals when the synchronized reserve requirement could not be met with tier 1, the market cleared an average of 751.2 MW of synchronized reserve (plus 236.1 MW of demand response) at a weighted average price of $12.20 per MWh.

The market clearing price for the MAD Subzone diverged from the RTO Zone in 1,001 intervals during the first nine months of 2022.

56 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.9 Synchronized Reserve Market Clearing Price (SRMCP) Calculation, Rev. 121 (July 7, 2022).

Supply, demand, and performance for tier 2 synchronized reserve cleared hours (price > $0) are reflected in the price of synchronized reserve (Table 10-16).

Table 10-16 RTO Zone, average SRMCP and average scheduled, tier 1 estimated and demand response MW in RT SCED market solutions: January 2021 through September 2022

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Interval Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Interval Tier 1 Synchronized Reserve Esitmate (MW)	Average Interval Demand Response Cleared (MW)
2021	Jan	$7.70	332.9	1,758.2	88.7
2021	Feb	$10.56	459.4	1,851.4	135.9
2021	Mar	$11.43	432.4	1,702.0	122.9
2021	Apr	$6.03	549.3	1,308.5	165.0
2021	May	$7.95	591.4	1,375.8	186.0
2021	Jun	$9.22	466.7	1,696.9	143.1
2021	Jul	$9.20	483.6	1,675.5	177.6
2021	Aug	$13.86	495.3	1,770.6	205.5
2021	Sep	$9.33	432.7	1,779.3	185.0
2021	Oct	$11.52	780.1	1,109.1	250.0
2021	Nov	$14.27	744.3	1,163.2	228.0
2021	Dec	$15.43	440.1	1,625.2	106.7
2021	Average	$10.83	518.7	1,563.7	166.6
2022	Jan	$21.89	357.5	1,713.9	107.4
2022	Feb	$16.17	255.8	1,949.3	99.6
2022	Mar	$14.21	447.5	1,515.3	139.9
2022	Apr	$16.64	594.8	1,154.8	171.5
2022	May	$15.74	602.9	1,476.7	192.0
2022	Jun	$31.01	652.1	1,535.5	219.7
2022	Jul	$17.32	590.1	1,468.2	189.3
2022	Aug	$18.74	656.5	1,432.1	244.5
2022	Sep	$16.47	448.8	1,592.0	212.4
2022	Average	$19.02	514.2	1,534.1	175.7

Settlement Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, the prices of synchronized reserve do not always cover the full cost to customers, including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis) but inflexible synchronized reserve commitment occurs prior to the hour, the realized, within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the tier 2 synchronized reserve market are guaranteed to be made whole and paid uplift credits in settlement if the SRMCP does not compensate them for their offer plus LOC.

PJM implemented fast start pricing on September 1, 2021. Between September 1, 2021 and December 31, 2021 prices were 2.1 percent higher than in the dispatch run (considering only intervals where the Tier 2 Synchronized Reserve price is greater than $0). In the first nine months of 2022, the average price was 26.1 percent higher in the pricing run than in the dispatch run. The price was above zero in the RTO Zone in 38.6 percent of intervals in the first nine months of 2022 (Table 10-17).

Prices were significantly higher in the first nine months of 2022 than they were in the first nine months of 2021 because of higher load, increased fuel costs and fast start pricing (Table 10-17). The MW weighted synchronized reserve market clearing price is computed for hours when the price was above $0. The market clearing solution includes a constraint that forces all remaining synchronized reserve to be cleared from the MAD Subzone (Figure 10-1) when one of the constraints defining MAD binds. RTO/MAD prices diverged in 1,001 intervals in the first nine months of 2022. In the first nine months of 2022, the MW weighted average tier 2 synchronized reserve clearing price was $16.16 in the RTO Zone and $18.14 in the MAD Subzone.

Table 10-17 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2021 through September 2022

Year	Month	Tier 2 Generation and DSR Credited MWh	Tier 2 SRMCP Credits	LOC Credits	Weighted Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price / Cost Ratio
2021	Jan	250,410	$1,366,533	$284,557	$5.46	$6.59	82.8%
2021	Feb	309,335	$1,371,901	$1,053,888	$4.44	$7.84	56.6%
2021	Mar	323,201	$2,116,589	$1,256,664	$6.55	$10.44	62.7%
2021	Apr	393,789	$1,393,286	$668,319	$3.54	$5.24	67.6%
2021	May	441,010	$2,600,987	$1,168,654	$5.90	$8.55	69.0%
2021	Jun	336,909	$1,749,251	$1,259,710	$5.19	$8.93	58.1%
2021	Jul	360,204	$1,426,976	$1,252,892	$3.96	$7.44	53.2%
2021	Aug	370,243	$2,598,840	$2,417,882	$7.02	$13.55	51.8%
2021	Sep	314,001	$1,754,993	$1,463,884	$5.59	$10.25	54.5%
2021	Oct	580,156	$6,156,577	$2,457,649	$10.61	$14.85	71.5%
2021	Nov	538,939	$7,479,685	$1,757,937	$13.88	$17.14	81.0%
2021	Dec	330,219	$3,907,943	$859,945	$11.83	$14.44	82.0%
2021		4,548,417	$33,923,562	$15,901,982	$7.46	$10.95	68.1%
2022	Jan	270,905	$4,165,719	$2,469,534	$15.38	$24.49	62.8%
2022	Feb	172,233	$1,828,245	$646,444	$10.61	$14.37	73.9%
2022	Mar	332,184	$4,006,135	$907,088	$12.06	$14.79	81.5%
2022	Apr	426,922	$6,490,248	$1,209,779	$15.20	$18.04	84.3%
2022	May	446,066	$6,528,859	$1,256,883	$14.64	$17.45	83.9%
2022	Jun	468,822	$13,205,921	$3,266,937	$28.17	$35.14	80.2%
2022	Jul	440,293	$7,255,855	$2,395,004	$16.48	$21.92	75.2%
2022	Aug	484,348	$7,920,363	$3,257,132	$16.35	$23.08	70.9%
2022	Sep	324,232	$2,982,950	$917,813	$9.20	$12.03	76.5%
2022		3,366,006	$54,384,294	$16,326,614	$16.16	$21.01	76.9%

Table 10-18 shows the effect of fast start pricing on the synchronized reserve market's monthly weighted average market clearing price from September 2021 through September 2022. The weighted average market clearing price for each month is consistently higher in the pricing run then in the dispatch run.

Table 10-18 Comparison of fast start and dispatch pricing components: September 2021 through September 2022

Year	Month	Pricing Method	Weighted Average Market Clearing Price
2021	Sep	Dispatch	$4.76
		Fast Start	$5.59
2021	Oct	Dispatch	$8.52
		Fast Start	$10.61
2021	Nov	Dispatch	$10.94
		Fast Start	$13.88
2021	Dec	Dispatch	$10.12
		Fast Start	$11.83
2022	Jan	Dispatch	$13.86
		Fast Start	$15.38
2022	Feb	Dispatch	$9.72
		Fast Start	$10.61
2022	Mar	Dispatch	$9.95
		Fast Start	$12.06
2022	Apr	Dispatch	$12.53
		Fast Start	$15.20
2022	May	Dispatch	$11.48
		Fast Start	$14.64
2022	Jun	Dispatch	$23.75
		Fast Start	$28.17
2022	Jul	Dispatch	$11.38
		Fast Start	$16.48
2022	Aug	Dispatch	$12.06
		Fast Start	$16.35
2022	Sep	Dispatch	$7.53
		Fast Start	$9.20

Performance

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[57] Tier 2 resource owners are paid for being available but are not paid based on the actual response to a synchronized reserve event. The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[58] When synchronized reserve resources self schedule or clear the Synchronized Reserve Market they are obligated to provide their full scheduled MW during a synchronized reserve event. Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after the start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[59] Clear synchronized reserve resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

Tier 2 performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Table 10-19 shows the average amount of scheduled Tier 2 MW that responded to events 10 minutes or longer from January 2016 through September 2022. Actual participant performance means that the penalty structure is not adequate to incent performance.

Table 10-19 Average tier 2 event response, January 2016 through September 2022

Year	No. of Events Longer than 10 Minutes	Average Percent of Scheduled Tier 2 MW that Responded
2016	7	85.5%
2017	6	87.6%
2018	8	74.2%
2019	3	86.8%
2020	5	59.5%
2021	5	76.9%
2022 (Jan - Sep)	3	51.4%

The penalty structure when a resource fails to respond fully to a spinning event includes two components. The first component is the forfeiture of awarded SRMCP credits in the amount of the MW of shortfall for the day on which the event occurred. The second component is a retroactive charge applied to the SRMCP credits paid in the Immediate Past Interval (IPI), equal to the sum of the SRMCPs for each scheduled interval within the IPI multiplied by the unit's penalty obligation on the day of the event. The IPI is calculated

57 See PJM. "PJM Manual 28: Operating Agreement Accounting", § 6.2.1 Synchronized Reserve Clearing Price Credit, Rev. 87 (July 27, 2022).
58 See *2011 State of the Market Report for PJM*, Vol. II, Section 9, "Ancillary Services," at p. 250.
59 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.5.1, Performance Verification, Rev. 122 (Oct. 1, 2022).

as the average number of days since the previous event over the previous two years or, if less, the number of days since the unit last failed to fully respond.

There are several problems with this penalty structure. First, resource owners are permitted to aggregate the response of multiple units, allowing owners to reduce the penalty obligation of a unit's underresponse by offsetting it with another unit's overresponse.[60] Second, the ISI is calculated using events of any length, even though a unit's compliance is automatically counted as 100 percent for events less than 10 minutes long, shortening the applied IPI significantly. Third, the second component of the penalty only applies to the SRMCP credits awarded during the IPI, ignoring the LOC credits, even though most credits are awarded for LOC.

Hence, the penalty structure for synchronized reserve nonperformance is inadequate for providing appropriate performance incentives. Under the penalty structure, it is possible for a resource to not respond to any spin events and yet still be paid for providing synchronized reserve. The MMU continues to recommend that the ISI be defined as the average number of days since the previous spinning event 10 minutes or longer and that the penalty's retroactive charges include the LOC credits in addition to the SRMCP credits. If only events 10 minutes or longer were considered, then the ISI would increase to 86 days from its current level of 22 days.[61] However, implementing this change alone might still have been insufficient to ensure proper response.

The MMU also continues to recommend that aggregation not be permitted to offset unit-specific penalties for failure to respond to a synchronized reserve event. Including aggregate responses from all online resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is unit specific, so the obligation to respond should also be unit specific. Any potentially offsetting response from an affiliated tier 1 resource should have been included as part of the reserves in the tier 1 estimate. Any potentially offsetting response from a tier 2 resource should have been included in that resource's tier 2 offer.

60 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 88 (Oct. 1, 2021).
61 The MMU recommended ISI was previously reported as 76 days.

Table 10-20 compares the outcomes of the PJM penalty structure for the first nine months of 2022 with the outcomes of the proposed MMU penalty structure following its recommendations. In the first nine months of 2022, there were three spinning events that lasted 10 minutes or longer: one on April 13, one on May 16, and one on May 23 (Table 10-21).

Table 10-20 Comparison of tier 2 shortfall penalties current IPI vs. MMU recommended: 2022

Penalty Type	Current PJM Penalty	MMU Recommended Penalty
Day Of Event	$44,070	$58,988
Retroactive Charges	$986,812	$94,937,075
Total Penalties	$1,030,882	$94,996,063

Spinning event response data as reported by PJM in its Operating Committee meetings is shown in Table 10-21. The tier 1 estimate is from the most recent RT SCED market solution. The tier 1 estimate includes estimated ramp only from the units that are eligible and excludes resources that have ramp available but are not part of the estimate.

Tier 1 synchronized reserve that responded to a spinning event received a bonus payment of $50 per MWh, based on a calculation using SCADA data, regardless of whether PJM included those reserves in the estimate.

Table 10-21 shows synchronized reserve event response compliance for tier 1 and tier 2 reserves for events that lasted 10 minutes or longer as reported by PJM, using only response from tier 1 estimated and tier 2 cleared reserves. In the first nine months of 2022, there were three events that were 10 minutes or longer. Actual synchronized reserve response is the total increase in MW from all resources from the moment the spinning event is called to 10 minutes after. To determine the actual tier 1 response, the calculation would subtract tier 2 response, changes in assigned regulation output (net compliance level to both RegA and RegD), and changes to net power flow across PJM's interface boundary. The overall response to spinning events is adequate or more than adequate to meet NERC requirements. PJM not only corrects the ACE disturbance that led to the event but over corrects. In all three of the spinning events the ACE recovered not just to the NERC required level (which is the lesser of 0 or the value before the disturbance which caused the event) but overshoots.

Table 10-21 Synchronized reserve events 10 minutes or longer, tier 1 and tier 2 response compliance as reported by PJM[62], RTO Reserve Zone: January 2019 through September 2022

Spin Event	Duration (Minutes)	Tier 1 Estimate (Market Solution MW Adj by DGP)	Response from Tier 1 DGP Estimated (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	DGP Estimated Tier 1 Response Percent	Tier 2 Response Percent
23-Sep-2019 1207 (EPT)	11	1,485.1	1,212.1	723.2	632.1	91.1	81.6%	87.4%
01-Oct-2019 1456 (EPT)	11	265.4	143.7	1,177.4	1,016.4	161.0	54.1%	86.3%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
18-Feb-2020 2015 (EPT)	10	2,216.1	1,434.8	40.0	1.7	38.3	64.7%	4.3%
06-Jul-2020 2122 (EPT)	10	1,464.0	526.1	479.7	415.1	64.6	35.9%	86.5%
25-Jul-2020 1639 (EPT)	11	868.4	421.6	302.3	264.8	37.5	48.5%	87.6%
10-Sep-2020 0029 (EPT)	10	1,275.4	453.6	782.6	782.6	0.0	35.6%	100.0%
16-Dec-2020 1649 (EPT)	10	268.4	196.9	527.6	413.2	114.4	73.4%	78.3%
2020 Average	10	1,218.5	606.6	426.4	375.5	51.0	49.7%	59.5%
09-Mar-2021 0750 (EPT)	10	1,354.9	635.4	884.0	540.8	343.2	46.9%	61.2%
30-Apr-2021 1630 (EPT)	12	1,487.6	610.2	508.3	407.2	101.1	41.0%	80.1%
26-May-2021 1017 (EPT)	10	1,138.4	811.0	685.2	600.2	85.0	71.2%	87.6%
23-Aug-2021 1644 (EPT)	18	879.8	597.5	896.2	667.1	229.1	67.9%	74.4%
12-Nov-2021 1725 (EPT)	12	510.0	606.7	890.7	714.6	176.1	119.0%	80.2%
2021 Average	12	1,074.1	652.2	772.9	586.0	186.9	69.2%	76.7%
13-Apr-2022 1725 (EPT)	28	651.9	390.0	880.6	718.4	162.2	59.8%	81.6%
16-May-2022 1532 (EPT)	11	1,490.0	895.3	295.0	91.8	203.2	60.1%	31.1%
23-May-2022 1717 (EPT)	15	757.7	670.4	1,062.2	707.8	354.4	88.5%	66.6%
2022 Average	18	967	652	746	506	240	69.5%	59.8%

Until April 2019, PJM's ASO market solution software allowed operators to bias the inflexible tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than the actual estimate. PJM, in response to the MMU recommendation, no longer uses tier 1 biasing in any of its market solutions. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution.

Tier 1 biasing was never referenced in PJM manuals or any public document. PJM could resume tier 1 biasing at its discretion. Although tier 1 biasing has been discontinued, PJM can and does still deselect tier 1 resources based on PJM judgment. The impact of tier 1 deselection can be very significant (Table 10-22).

62 *See, for example*, "Systems Operations Report," PJM presentation to the Operating Committee. (April 14, 2022) <https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20220414/item-02---review-of-operating-metrics.ashx> at 10.

Table 10-22 Comparison of spinning event market solution tier 1 estimate, tier 1 response with PJM Settlements tier 1 MW credited: January 2021 through September 2022

Start Time	Duration (Minutes)	PJM Market Solution DGP Estimated Tier 1 Estimate MW	PJM Market Solution DGP Estimated Tier 1 Response MW	PJM Settlements Tier 1 Credited Response MWh
24-Jan-2021 2232 (EPT)	6.5	2,134.5	577.9	1,165.0
09-Mar-2021 0750 (EPT)	10.8	1,354.9	635.4	1,715.9
13-Apr-2021 1605 (EPT)	8.8	2,093.4	975.6	2,534.3
30-Apr-2021 1630 (EPT)	11.6	1,487.6	610.2	2,143.5
26-May-2021 1017 (EPT)	10.0	1,138.4	811.0	2,618.6
21-Jun-2021 0154 (EPT)	6.9	2,340.8	1,764.1	1,806.7
22-Jun-2021 2333 (EPT)	4.7	2,277.0	1,367.8	1,376.5
21-Jul-2021 1827 (EPT)	5.0	837.8	290.8	881.3
25-Jul-2021 1616 (EPT)	6.0	708.7	418.8	2,117.9
23-Aug-2021 1644 (EPT)	17.6	879.8	597.5	2,050.4
24-Aug-2021 1037 (EPT)	8.1	903.7	658.3	2,615.9
27-Sep-2021 1656 (EPT)	8.4	679.5	385.1	3,058.7
11-Oct-2021 1323 (EPT)	9.3	1,215.9	577.8	4,015.5
16-Oct-2021 0530 (EPT)	7.7	1,060.4	669.1	2,254.0
12-Nov-2021 1725 (EPT)	12.1	510.0	606.7	5,275.5
30-Nov-2021 0940 (EPT)	9.8	899.2	678.3	3,476.1
30-Nov-2021 1256 (EPT)	8.5	948.6	452.3	4,378.5
08-Dec-2021 0904 (EPT)	7.8	481.6	288.8	1,645.6
03-Jan-2022 1227 (EPT)	8.9	516.8	377.6	2,029.0
03-Mar-2022 1220 (EPT)	7.4	1,398.9	795.8	2,402.9
06-Apr-2022 1145 (EPT)	9.7	413.9	393.0	4,161.6
13-Apr-2022 1725 (EPT)	28.5	651.9	390.0	12,253.0
14-Apr-2022 0930 (EPT)	8.1	691.7	432.7	2,934.9
16-May-2022 1532 (EPT)	11.1	1,490.0	895.3	5,438.2
16-May-2022 1553 (EPT)	9.6	1,169.6	912.7	6,071.6
23-May-2022 1717 (EPT)	15.0	757.7	670.4	4,630.2
26-May-2022 1409 (EPT)	6.3	557.7	360.4	2,018.4
22-Jun-2022 1506 (EPT)	7.2	658.8	305.5	2,617.8
27-Jun-2022 1701 (EPT)	9.1	516.7	595.5	3,446.1
07-Jul-2022 1721 (EPT)	7.9	805.8	522.0	3,345.7
26-Sep-2022 0339 (EPT)	6.0	2,543.3	1,593.1	2,761.2
29-Sep-2022 1025 (EPT)	6.2	437.6	619.2	3,411.2

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[63] [64] A disturbance is defined as loss of the lesser of 900 MW or 80 percent of the largest single contingency within 60 seconds. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicate no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbances.

From January 2018 through September 2022, PJM experienced 80 synchronized reserve events, approximately 1.4 events per month, with an average duration of 8.9 minutes. Table 10-23 shows these events with their region and their duration rounded to the nearest minute.

63 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
64 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 47 (Oct. 1, 2022).

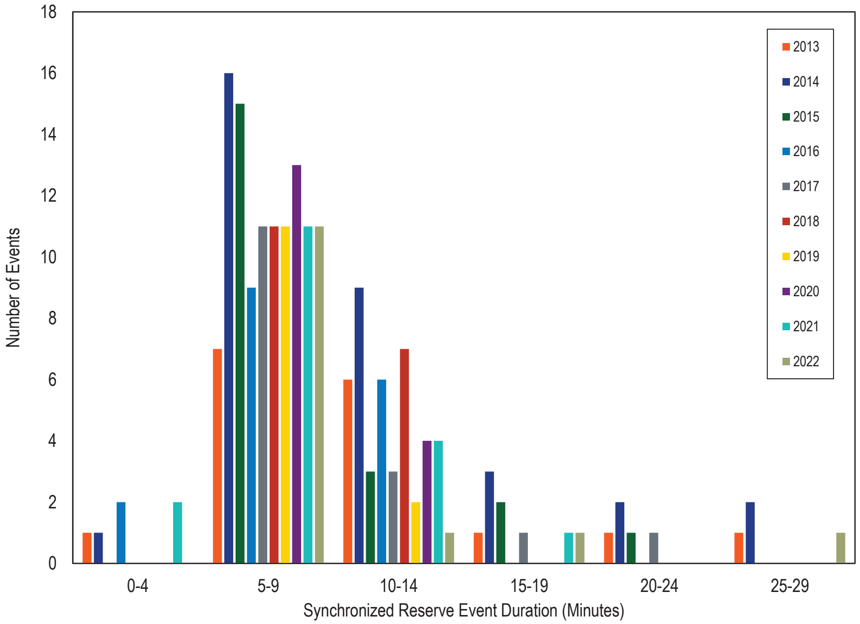
Table 10-23 Synchronized reserve events: January 2018 through September 2022[65]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
01-Jan-2018 0241 (EPT)	RTO	7	20-Jan-2020 1406 (EPT)	MAD	8	03-Jan-2022 1227 (EPT)	RTO	9
03-Jan-2018 0300 (EPT)	RTO	13	23-Jan-2020 1617 (EPT)	RTO	9	03-Mar-2022 1220 (EPT)	RTO	7
07-Jan-2018 1415 (EPT)	RTO	9	07-Feb-2020 1206 (EPT)	RTO	6	06-Apr-2022 1145 (EPT)	RTO	10
12-Apr-2018 1328 (EPT)	RTO	10	08-Feb-2020 0344 (EPT)	RTO	8	13-Apr-2022 1725 (EPT)	RTO	28
04-Jun-2018 1022 (EPT)	RTO	6	10-Feb-2020 2015 (EPT)	RTO	9	14-Apr-2022 0931 (EPT)	RTO	8
29-Jun-2018 1521 (EPT)	RTO	9	18-Feb-2020 1116 (EPT)	RTO	10	16-May-2022 1532 (EPT)	RTO	11
30-Jun-2018 0946 (EPT)	RTO	11	08-Mar-2020 0517 (EPT)	MAD	5	16-May-2022 1553 (EPT)	RTO	10
04-Jul-2018 1056 (EPT)	RTO	7	13-Apr-2020 2001 (EPT)	RTO	8	23-May-2022 1717 (EPT)	RTO	15
10-Jul-2018 1545 (EPT)	RTO	13	03-May-2020 1229 (EPT)	RTO	6	26-May-2022 1409 (EPT)	RTO	6
23-Jul-2018 0902 (EPT)	RTO	8	06-Jul-2020 2122 (EPT)	RTO	10	22-Jun-2022 1506 (EPT)	RTO	7
23-Jul-2018 1543 (EPT)	RTO	6	24-Jul-2020 0103 (EPT)	RTO	9	27-Jun-2022 1701 (EPT)	RTO	9
24-Jul-2018 1617 (EPT)	RTO	7	25-Jul-2020 1639 (EPT)	MAD	11	07-Jul-2022 1721 (EPT)	RTO	8
12-Aug-2018 1106 (EPT)	RTO	11	10-Sep-2020 0019 (EPT)	RTO	10	26-Sep-2022 0339 (EPT)	RTO	6
13-Sep-2018 0947 (EPT)	RTO	7	10-Oct-2020 1852 (EPT)	RTO	8	29-Sep-2022 1025 (EPT)	RTO	6
14-Sep-2018 1324 (EPT)	RTO	7	12-Oct-2020 0429 (EPT)	RTO	9			
26-Sep-2018 1908 (EPT)	RTO	8	13-Nov-2020 0746 (EPT)	RTO	6			
30-Sep-2018 1129 (EPT)	RTO	11	16-Dec-2020 1638 (EPT)	MAD	10			
30-Oct-2018 1040 (EPT)	RTO	11						
22-Jan-2019 2230 (EPT)	RTO	8	24-Jan-2021 2232 (EPT)	RTO	6			
31-Jan-2019 0126 (EPT)	RTO	5	09-Mar-2021 0751 (EPT)	RTO	11			
31-Jan-2019 0926 (EPT)	RTO	9	13-Apr-2021 2005 (EPT)	RTO	9			
25-Feb-2019 0025 (EPT)	RTO	9	30-Apr-2021 2030 (EPT)	RTO	12			
03-Mar-2019 1231 (EPT)	RTO	9	26-May-2021 1417 (EPT)	RTO	10			
06-Mar-2019 2206 (EPT)	RTO	9	21-Jun-2021 0554 (EPT)	RTO	7			
27-Jul-2019 2331 (EPT)	RTO	7	23-Jun-2021 0333 (EPT)	RTO	5			
11-Aug-2019 1214 (EPT)	RTO	8	21-Jul-2021 1828 (EPT)	RTO	5			
03-Sep-2019 1339 (EPT)	MAD	9	25-Jul-2021 1617 (EPT)	RTO	6			
23-Sep-2019 1606 (EPT)	RTO	11	23-Aug-2021 1644 (EPT)	RTO	18			
01-Oct-2019 1856 (EPT)	RTO	11	24-Aug-2021 1038 (EPT)	RTO	8			
11-Dec-2019 2108 (EPT)	RTO	8	27-Sep-2021 1656 (EPT)	RTO	8			
18-Dec-2019 1507 (EPT)	RTO	9	11-Oct-2021 0923 (EPT)	RTO	9			
			16-Oct-2021 0130 (EPT)	RTO	8			
			12-Nov-2021 1325 (EPT)	RTO	12			
			30-Nov-2021 0540 (EPT)	RTO	9			
			30-Nov-2021 0957 (EPT)	RTO	9			
			08-Dec-2021 0504 (EPT)	RTO	7			

65 For full history of spinning events, see the *2019 State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

Figure 10-7 shows spin event durations over the past five years.[66]

Figure 10-7 Synchronized reserve events duration distribution curve: January 2013 through September 2022



Nonsynchronized Reserve Market

Nonsynchronized reserve consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing and is based on parameters in offers submitted by resource owners. There is no defined requirement for nonsynchronized reserves. It is available to meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

66 These durations were rounded to the nearest minute in previous reports. They are no longer rounded.

The market mechanism for nonsynchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers. Since nonsynchronized reserve is a lower quality product, its clearing price is less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

Demand for primary reserve is established by PJM as one and a half times the largest contingency. Demand for primary reserve is calculated dynamically in every synchronized and nonsynchronized reserve market solution. After filling the synchronized reserve requirement the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. In practice this means that the primary reserve requirement minus the scheduled synchronized reserve is the nonsynchronized requirement for the interval. PJM may increase the primary reserve requirement to cover times when a single contingency could cause an outage of several generating units or in times of high load conditions causing operational uncertainty.[67]

The average scheduled hourly nonsynchronized reserve in the RTO Zone in the first nine months of 2022 was 1,122.7 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve was 1,109.7 MW.

Supply

Figure 10-2 shows that when tier 1 synchronized reserve did not fully meet the synchronized reserve requirement, then most of the primary reserve

67 See PJM. "PJM Manual 11: Energy and Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).

requirement (blue line) in excess of the synchronized reserve requirement (purple line) was satisfied by nonsynchronized reserve (green area).

There are no offers for nonsynchronized reserve. The market solution considers the available supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have set themselves as unavailable or have set their output to be emergency only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. The market supply curve is constructed from the nonsynchronized units' opportunity cost of providing reserves. PJM and generation owners may agree upon exceptions to the requirements.

Nonsynchronized reserve resources are scheduled economically based on estimated LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined every five minutes based on the LOC of the marginal unit. When a unit clears the nonsynchronized reserve market and is scheduled, it is committed to remain offline and available to provide 10 minute reserves.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles that can start in 10 minutes or less, and diesels. In the first nine months of 2022, an average of 1,122.7 MW of nonsynchronized reserve was scheduled per five minute interval out of 2,015.6 eligible MW as part of the primary reserve requirement in the RTO Zone. If only intervals when the price was greater than $0 are looked at, then an average of 612.8 MW of nonsynchronized reserve is scheduled out of 1,108.7 MW available.

In the first nine months of 2022, CTs provided 80.4 percent of scheduled nonsynchronized reserve (Table 10-24). Natural gas was the primary fuel for nonsynchronized reserve.

Table 10-24 Supply of nonsynchronized reserve by fuel and unit type: January through September, 2022

Resource / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	46.2%	27.0%
CT - Oil	34.2%	34.5%
Hydro - Run of River	19.0%	37.1%
CT - Other	0.2%	0.8%
Hydro - Pumped Storage	0.2%	0.1%
RICE - Oil	0.2%	0.5%
Battery	0.0%	0.0%
Combined Cycle	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Natural Gas	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Coal	0.0%	0.0%
Steam - Natural Gas	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first nine months of 2022. Table 10-25 shows the percent of dispatch solutions with a real-time nonsynchronized reserve market clearing price greater than $0.01 that failed the three pivotal supplier test. In the first nine months of 2022, on average, there were 66 dispatch cases each month with a real-time price above $0.01, of which 96.7 percent had at least one pivotal supplier. In the first nine months of 2022, in total, 569 of the 591 tested cases had at least one pivotal supplier.

Table 10-25 Percent of dispatch solutions with NSRMCP greater than $0.01 failing the three pivotal supplier test: January through September, 2022

Year	Month	Number of Dispatch Cases NSR MCP > $0.01	Percent of Dispatch Cases NSR MCP > $0.01 Pivotal
2022	Jan	16	100.0%
2022	Feb	0	NA
2022	Mar	29	100.0%
2022	Apr	56	100.0%
2022	May	233	99.6%
2022	Jun	117	95.7%
2022	Jul	25	100.0%
2022	Aug	80	81.3%
2022	Sep	35	97.1%
2022	Average	66	96.7%

Price

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-8 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Zone. In the first nine months of 2022, the weighted average nonsynchronized market clearing price for all intervals was $0.25 per MW. The average nonsynchronized reserve credited was 1,122.7 MW. Shortage pricing for primary reserve was used during 35 intervals on June 13. The average price during these short intervals was $731.71 per MW.

Figure 10-8 Daily weighted average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through September, 2022

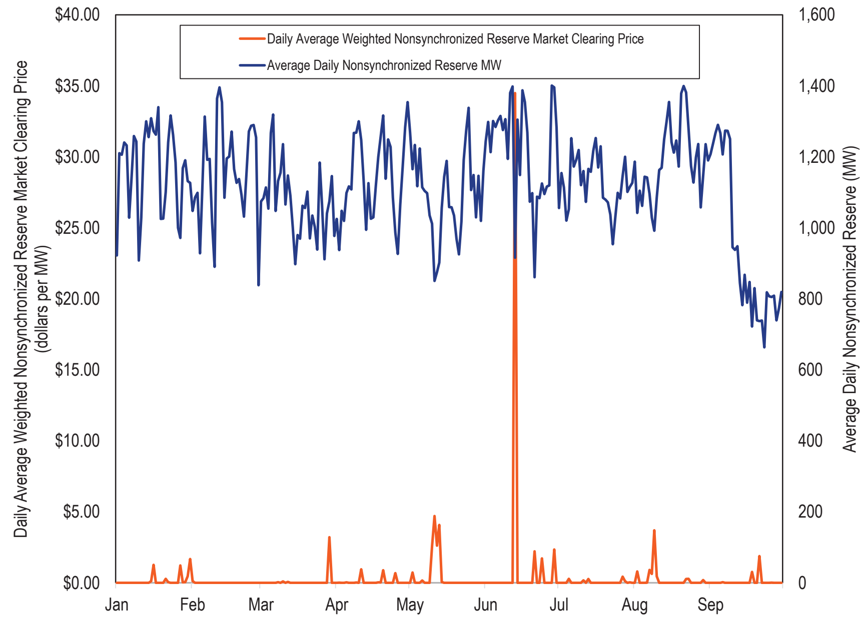


Table 10-26 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price since September 2021. The weighted average market clearing price for each month is consistently higher in the pricing run than in the dispatch run. In the first nine months of 2022, the average price from the pricing run was 20.1 percent higher than the average price from the dispatch run.

Table 10-26 Comparison of fast start and dispatch pricing components: September 2021 through September 2022

Year	Month	Pricing Method	Weighted Average Market Clearing Price
2021	Sep	Dispatch	$0.19
		Fast Start	$0.20
2021	Oct	Dispatch	$0.62
		Fast Start	$0.80
2021	Nov	Dispatch	$0.98
		Fast Start	$1.23
2021	Dec	Dispatch	$0.02
		Fast Start	$0.04
2022	Jan	Dispatch	$0.15
		Fast Start	$0.16
2022	Feb	Dispatch	$0.00
		Fast Start	$0.00
2022	Mar	Dispatch	$0.11
		Fast Start	$0.11
2022	Apr	Dispatch	$0.08
		Fast Start	$0.09
2022	May	Dispatch	$0.27
		Fast Start	$0.40
2022	Jun	Dispatch	$0.93
		Fast Start	$1.05
2022	Jul	Dispatch	$0.02
		Fast Start	$0.04
2022	Aug	Dispatch	$0.16
		Fast Start	$0.21
2022	Sep	Dispatch	$0.06
		Fast Start	$0.06

Price and Cost

As a result of changing grid conditions, load forecasts, incorrect LMP and lost opportunity cost projections, and unexpected generator performance, prices frequently do not cover the full LOC of each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the NSRMCP does not fully compensate them. When real-time LMP is greater than the generator's incremental energy offer at economic minimum, then an LOC is paid, even if LMP revenue would not have covered the unit's start and no load costs.[68]

The full cost to customers of nonsynchronized reserve credits, including payments for the clearing price and uplift costs is calculated and compared to the price in Table 10-27. The closer the price to cost ratio comes to one, the more compensation is provided.

In the first nine months of 2022, the average price of nonsynchronized reserve was $0.25 per MW. The average credit for nonsynchronized reserve was $2.11 per MW.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP increases above its energy offer. In that case, PJM pays the unit LOC. The LOC calculation does not consider the start cost or the no load cost of committing the unit for energy, which would reduce the LOC in almost all cases. In fact, in its filing to change the reserve market design, PJM explained that nonsynchronized reserves have no lost opportunity cost.[69]

68 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 121 (July 7, 2022).

69 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.

Table 10-27 RTO zone nonsynchronized reserve MW, charges, price, and cost: January 2021 through September 2022

Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
2021	Jan	879,221	$533,379	$0.04	$0.61	6.4%
2021	Feb	705,279	$598,281	$0.16	$0.85	18.6%
2021	Mar	759,861	$1,612,024	$0.33	$2.12	15.5%
2021	Apr	752,169	$425,518	$0.09	$0.57	16.7%
2021	May	725,583	$1,792,770	$0.38	$2.47	15.6%
2021	Jun	801,961	$965,259	$0.13	$1.20	10.7%
2021	Jul	821,187	$776,427	$0.13	$0.95	13.6%
2021	Aug	819,528	$2,610,204	$0.26	$3.19	8.3%
2021	Sep	762,247	$1,552,275	$0.20	$2.04	9.9%
2021	Oct	680,605	$1,428,602	$0.80	$2.10	38.2%
2021	Nov	762,277	$2,914,501	$1.23	$3.82	32.2%
2021	Dec	832,563	$1,565,673	$0.04	$1.88	2.0%
2021	Total	9,302,479	$16,774,913	$0.31	$1.80	16.9%
2022	Jan	864,970	$8,051,383	$0.16	$9.31	1.7%
2022	Feb	772,554	$327,456	$0.00	$0.42	1.0%
2022	Mar	793,267	$417,124	$0.11	$0.53	21.3%
2022	Apr	818,987	$564,075	$0.09	$0.69	13.6%
2022	May	812,337	$1,588,098	$0.40	$1.95	20.7%
2022	Jun	875,976	$1,899,497	$1.05	$2.17	48.6%
2022	Jul	829,558	$664,719	$0.04	$0.80	5.3%
2022	Aug	877,569	$1,205,091	$0.21	$1.37	15.1%
2022	Sep	673,825	$710,665	$0.06	$1.05	6.1%
2022	Total	7,319,043	$15,428,108	$0.25	$2.11	11.8%

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a defined reserve product to maintain this reserve requirement in real time.[70]

PJM maintains a day-ahead, offer based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[71]

Market Structure

Supply

Both generation and demand resources are eligible to offer DASR. DASR offers consist of price only. Available DASR MW are calculated by the market clearing engine. DASR MW are the lesser of the energy ramp rate per minute for online units times 30 minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in 30 minutes, the DASR quantity is the economic maximum. In the first nine months of 2022, the DASR hourly average purchased was 4,820.4 MW.[72]

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR market. Such resources include nuclear, run of river hydro, self-scheduled pumped hydro, wind, solar, and energy storage resources.[73] The intent is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default noneligibility.

70 The reserve market changes, effective October 1, 2022, define a 30-minute reserve service which could be satisfied by a secondary reserve product cleared in the day-ahead and real-time markets.
71 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 121 (July 7, 2022).
72 The average hourly available DASR MW are modified from previously reported values because of a calculation error which has been fixed.
73 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 121 (July 7, 2022).

Of the scheduled DASR MW cleared in the first nine months of 2022, 78.7 percent was from CTs (Table 10-28).

Table 10-28 Scheduled DASR by fuel and unit type: January through September, 2022

Resource / Fuel Type	Percentage of DASR MW	Percentage of DASR Credits
CT - Natural Gas	61.0%	61.4%
CT - Oil	17.7%	17.7%
Hydro - Pumped Storage	12.9%	4.3%
Combined Cycle	4.3%	9.2%
Steam - Coal	3.4%	3.5%
RICE - Oil	0.3%	0.9%
Steam - Natural Gas	0.2%	2.4%
RICE - Other	0.1%	0.4%
RICE - Natural Gas	0.0%	0.1%
Steam - Other	0.0%	0.1%
Steam - Oil	0.0%	0.0%
CT - Other	0.0%	0.0%
Battery	0.0%	0.0%
DSR	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%
Nuclear	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

Secondary reserve (30 minute reserve) requirements are determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under forecasted load rates and generator forced outage rates.[74] The DASR requirement is calculated daily and is equal to the peak load forecast for the Reliability*First* region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. Effective November 1, 2021, through September 30, 2022, the day-ahead scheduling reserve requirement is 4.40 percent of the peak load forecast, based on a 2.03 percent LFE component and a 2.38 percent FOR component. The DASR requirement is applicable for all hours of the operating day.

The DASR requirement can be increased by PJM operators under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[75] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[76] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year. For November 2021 through October 2022, the SCD values are 5.84 percent for winter and 4.06 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[77] PJM has defined the reasons for conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state, physical or cyber attacks.[78] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand in 547hours during the first nine months of 2022. The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. The MMU further recommends that PJM attach a reason code to all hours when adjusted fixed demand is dispatched. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-29. Table 10-29 shows the percent of intervals with a day-ahead scheduling reserve market clearing price greater than $0.01 that failed the three pivotal supplier test. In the first nine months of 2022, on average, there were 85

74 See PJM. "PJM Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 84 (Mar. 23, 2022).

75 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.

76 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement, Rev. 121 (July 7, 2022).

77 See *id.*

78 See PJM. "PJM Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 85 (Oct. 1, 2022).

testable intervals each month, of which 90.0 percent had at least one pivotal supplier. In total, there were 769 testable intervals, of which 603, or 78.4 percent, had at least one pivotal supplier.

Table 10-29 DASR market three pivotal supplier test results and number of hours with DASR MCP above $0.01: January 2021 through September 2022

Year	Month	Number of Hours DASR MCP > $0.01	Percent of Hours DASR MCP > $0.01 Pivotal
2021	Jan	15	100.0%
2021	Feb	26	100.0%
2021	Mar	23	100.0%
2021	Apr	93	98.9%
2021	May	79	87.3%
2021	Jun	151	78.1%
2021	Jul	148	95.9%
2021	Aug	153	84.3%
2021	Sep	131	86.3%
2021	Oct	171	98.8%
2021	Nov	140	98.6%
2021	Dec	33	100.0%
2021	Average	97	94.0%
2022	Jan	43	100.0%
2022	Feb	12	100.0%
2022	Mar	42	90.5%
2022	Apr	16	100.0%
2022	May	62	72.6%
2022	Jun	142	84.5%
2022	Jul	212	86.8%
2022	Aug	168	86.3%
2022	Sep	72	88.9%
2022	Average	85	90.0%

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR market.[79] Units that do not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

Economic withholding remains an issue in the DASR market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In the first nine months of 2022, 43.7 percent of generation units offered DASR at a daily price above $0.00 per MW. In the first nine months of 2022, 16.9 percent of daily offers were above $5.00 per MW.

The MMU recommends that market solutions for the DASR market be based on opportunity cost only in order to eliminate economic withholding. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

Market Performance

In the first nine months of 2022, the DASR market cleared at a price above $0.00 per MW in 12.6 percent of all hours. The weighted average DASR price for all cleared hours was $0.35 per MW. The average cleared MW in all hours was 4,820.2 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 6,321.3 MW. The highest DASR price in the first nine months of 2022 was $34.00 per MW for one hour on May 31.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market. Table 10-30 shows the use of AFD in previous years. Table 10-31 shows the use of AFD in the first nine months of 2022. In the first nine months of 2022, AFD hours were only used in the months of January, May, June, July, August, and September. The resulting differences in market clearing price, MW cleared, and charges to PJM load from use of AFD could be substantial, as seen in Table 10-33 Table 10-32 shows the differences in price and MW between AFD hours and non-AFD hours in the first nine months of 2022.

79 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 121 (July 7, 2022).

Table 10-30 Hours with Adjusted Fixed Demand (AFD) added to the normal DASR requirement: 2015 through 2021

Year	Number of Hours with AFD	Normal Requirement as Percent of Forecast Load
2015	367	5.9%
2016	522	5.7%
2017	336	5.5%
2018	598	5.3%
2019	447	5.3%
2020	430	5.1%
2021	516	5.5%

Table 10-31 Hours with Adjusted Fixed Demand (AFD) and average increase in DASR requirement: January through September, 2022

Year	Month	Number of Hours with AFD	Average Increase in Requirement
2022	Jan	16	15.2%
2022	Feb	0	NA
2022	Mar	0	NA
2022	Apr	0	NA
2022	May	63	65.1%
2022	Jun	67	74.4%
2022	Jul	214	26.3%
2022	Aug	163	30.8%
2022	Sep	24	20.0%
2022	Total	547	37.0%

Table 10-32 Impact of Adjusted Fixed Demand on DASR prices and demand: January through September, 2022

Metric	Number of Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All hours	6,551	$0.35	4,626.5
All hours when DASRMCP > $0	827	$2.28	5,702.3
All hours when AFD used	547	$2.15	7,292.5

While the new rules allowed PJM operators' substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM operators add additional DASR MW above the default DASR hourly requirement. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

Comparing the Normal Hour column against the AFD Hour column for five metrics (Table 10-33) shows that the use of AFD for 574 hours in the first nine months of 2022 significantly increased the cost of DASR by increasing the DASR MW cleared. Table 10-33 shows the cost increase. The average DASR clearing price in the first nine months of 2022 was $0.77 per MW for hours when the clearing price was above $0.00 and $4.49 per MW during hours when adjusted fixed demand was invoked by PJM Dispatch.

Table 10-33 DASR market, regular hours vs. adjusted fixed demand hours with price greater than $0: January 2021 through September 2022

		Number of Hours DASRMCP > $0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2021	Jan	28	NA	$0.08	NA	106,153	NA	4,847	NA	$380	NA
2021	Feb	32	NA	$0.16	NA	108,947	NA	4,974	NA	$815	NA
2021	Mar	24	NA	$0.17	NA	92,014	NA	4,327	NA	$732	NA
2021	Apr	129	NA	$0.21	NA	83,962	NA	3,983	NA	$846	NA
2021	May	68	11	$0.60	$1.91	99,007	105,454	4,661	9,514	$2,785	$18,147
2021	Jun	83	77	$0.41	$4.55	115,654	118,494	5,170	8,973	$2,124	$40,839
2021	Jul	115	46	$0.44	$1.41	122,396	129,739	5,460	7,842	$2,424	$11,095
2021	Aug	110	83	$0.35	$3.85	121,022	133,350	5,399	7,869	$1,877	$30,312
2021	Sep	107	40	$0.58	$3.45	104,852	105,046	4,776	9,117	$2,769	$31,492
2021	Oct	222	NA	$0.50	NA	87,526	NA	4,335	NA	$2,159	NA
2021	Nov	228	NA	$0.30	NA	89,025	NA	4,208	NA	$1,258	NA
2021	Dec	41	NA	$0.26	NA	100,378	NA	4,544	NA	$1,188	NA
2021		1,187	257	$0.39	$3.51	99,647	122,653	4,633	8,460	$1,791	$29,689
2022	Jan	52	1	$0.29	$0.19	114,012	116,746	4,799	4,856	$1,407	$923
2022	Feb	13	NA	$0.31	NA	112,857	NA	4,542	NA	$1,390	NA
2022	Mar	42	NA	$0.49	NA	98,063	NA	4,368	NA	$2,124	NA
2022	Apr	22	NA	$0.18	NA	88,142	NA	3,818	NA	$681	NA
2022	May	45	31	$0.29	$8.26	97,273	113,745	4,196	9,418	$1,237	$77,802
2022	Jun	110	42	$1.55	$4.23	118,219	115,167	5,017	9,746	$7,764	$41,216
2022	Jul	132	89	$0.59	$3.10	119,220	131,062	5,006	7,333	$2,958	$22,748
2022	Aug	103	68	$0.73	$4.58	121,415	128,332	4,969	7,413	$3,609	$33,967
2022	Sep	69	8	$0.96	$2.09	108,371	110,701	4,584	5,915	$4,380	$12,334
2022		588	239	$0.77	$4.49	113,189	124,504	4,771	7,992	$3,690	$35,886

Table 10-34 shows total number of hours when a DASR market cleared at a price above $0 along with average load, cleared MW, additional MW under AFD, and total charges for the DASR market in January 2021 through September 2022.

Table 10-34 DASR market all hours of DASR market clearing price greater than $0: January 2021 through September 2022

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	PJM Cleared DASR MW	PJM Cleared Additional DASR MW	Credits
2021	Jan	28	$0.08	106,153	135,710	0	$10,640
2021	Feb	32	$0.16	108,947	159,163	0	$26,076
2021	Mar	24	$0.17	92,014	103,839	0	$17,564
2021	Apr	129	$0.21	83,962	513,819	0	$109,108
2021	May	79	$0.92	99,905	421,593	53,470	$389,001
2021	Jun	160	$2.97	117,021	1,120,041	351,422	$3,320,941
2021	Jul	161	$0.80	124,494	988,574	97,972	$789,171
2021	Aug	193	$2.18	126,324	1,246,974	168,469	$2,722,344
2021	Sep	147	$1.78	104,905	875,744	150,928	$1,555,947
2021	Oct	222	$0.50	87,526	962,369	0	$479,311
2021	Nov	228	$0.30	89,025	959,331	0	$286,853
2021	Dec	41	$0.26	100,378	186,320	0	$48,719
2021	Total	1,444	$1.27	103,741	7,673,478	822,262	$9,755,675
2022	Jan	53	$0.29	114,063	254,387	1,089	$74,083
2022	Feb	13	$0.31	112,857	59,044	0	$18,065
2022	Mar	42	$0.49	98,063	183,452	0	$89,213
2022	Apr	22	$0.18	88,142	83,989	0	$14,973
2022	May	76	$5.13	103,992	480,783	148,406	$2,467,548
2022	Jun	152	$2.69	117,376	961,196	209,266	$2,585,054
2022	Jul	221	$1.84	123,989	1,313,439	178,880	$2,415,045
2022	Aug	171	$2.64	124,166	1,015,863	156,422	$2,681,484
2022	Sep	77	$1.10	108,613	363,635	10,696	$400,897
2022	Total	827	$2.28	116,459	4,715,788	704,759	$10,746,362

When the DASR requirement was increased by PJM dispatch, the reserve requirement frequently could not be met without redispatching online resources which significantly affected the price by creating an LOC.

Regulation Market

Regulation matches generation with short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market.

Market Design

PJM's regulation market design is a result of Order No. 755.[80] The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types in a single market.

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The regulation market solution is intended to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the regulation market will substitute RegD MW for RegA MW when RegD is

80 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the MBF. The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per marginal effective MW.

The marginal rate of technical substitution (MRTS) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2 per MW with a MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF times 1.00 performance score times 1 MW). The total offer price would be $4 per effective MW ($2 per MW offer divided by the 0.5 effective MW).

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[81] Performance scores are reported on an hourly basis for each resource.

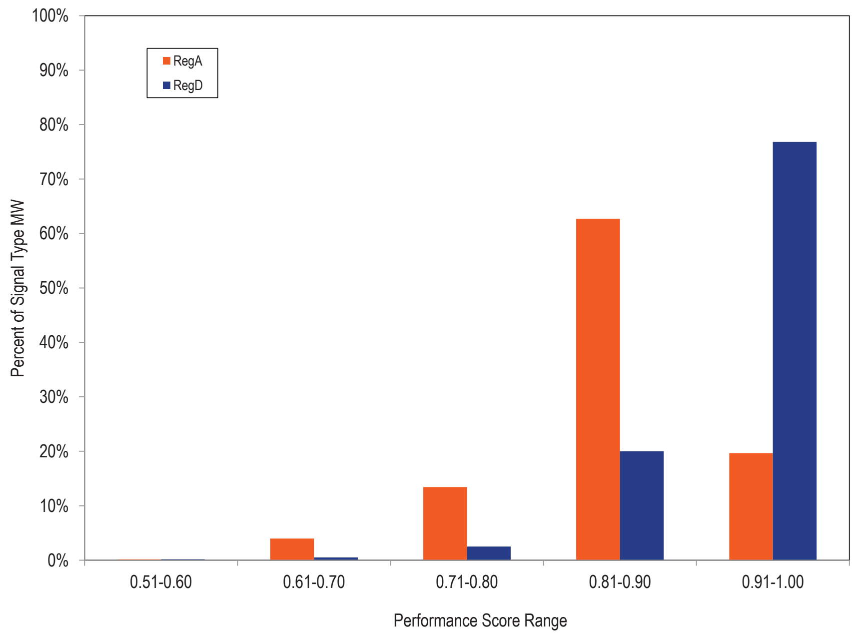
Table 10-35 and Figure 10-9 show the average performance score by resource type and the signal followed in the first nine months of 2022. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[82] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-9 shows, 76.8 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 19.7 percent of RegA resources had average performance scores within that range in the first nine months of 2022. In the first nine months of 2021, 76.7 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 26.4 percent of RegA resources had average performance scores within that range.

Table 10-35 Hourly average performance score by unit type: January through September, 2022

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	0.0%	0.0%	1.6%	59.7%	38.8%
	Diesel	0.0%	0.0%	0.0%	21.6%	78.4%
	DSR	-	-	-	-	-
	Hydro	0.0%	0.0%	0.1%	57.4%	42.5%
	Steam	0.2%	5.5%	18.5%	64.9%	10.8%
RegD	Battery	0.2%	0.0%	0.1%	18.0%	81.7%
	CT	0.0%	0.0%	15.1%	69.3%	15.6%
	Diesel	0.0%	0.0%	3.7%	55.1%	41.3%
	DSR	0.0%	0.2%	21.5%	27.2%	51.1%
	Hydro	0.0%	16.7%	0.0%	29.6%	53.8%
	Steam	-	-	-	-	-

81 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 47 (Oct. 1, 2022).
82 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Figure 10-9 Hourly average performance score by regulation signal type: January through September, 2022



Each cleared resource in a class (RegA or RegD) is allocated a portion of the class signal (RegA or RegD). This portion of the class signal is based on the cleared regulation MW of the resource relative to the cleared MW for that class. This signal is called the Total Regulation Signal (TREG) for the resource. A resource with 10 MW of capability will be provided a TREG signal asking for a positive or negative regulation movement between negative and positive 10 MW around its regulation set point.

Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits, which are uplift payments. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference. PJM posts clearing prices for the regulation market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in $/effective MW) for the hour is the simple average of the 12 five minute RMCPs within the hour. The RMCP is set in each five minute interval based on the marginal offer in each interval. The performance clearing price (RMPCP in $/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price (RMCCP in $/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour. This is done so the total of RMPCP plus RMCCP equals the total clearing price (RMCP) but the RMPCP is maximized.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT SCED) solving approximately every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The marginal prices assigned by the LPC to five minute intervals are averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and is not efficient or competitive. The market results do not represent the least cost solution for the defined level of regulation service.

In a well functioning market, every resource should be paid the same clearing price per unit produced. That is not true in the PJM Regulation Market. RegA and RegD resources are not paid the same clearing price in dollars per effective MW. RegD resources are being paid more than the market clearing price. This flaw in the market design has caused operational issues, has caused over investment in RegD resources.

If all MW of regulation were treated the same in both the clearing of the market and in settlements, many of the issues in the PJM Regulation Market would be resolved. However, the current PJM rules result in the payment to RegD resources being up to 1,000 times the correct price.

RegA and RegD have different physical capabilities. In order to permit RegA and RegD to compete in the single PJM Regulation Market, RegD must be translated into the same units as RegA. One MW of RegA is one effective MW. The translation is done using the marginal benefit factor (MBF). As more RegD is added to the market, the relative value of RegD declines, based on its actual performance attributes. For example, if the MBF is 0.001, a MW of RegD is worth 0.001 MW of RegA (or 1/1,000 of a MW of RegA). This is the same thing as saying that 1.0 MW of RegD is equal to 0.001 effective MW when the MBF is 0.001.

Almost all of the issues in PJM's Regulation Market are caused by the inconsistent application of the MBF. Because the MBF is not included in settlements, when the MBF is less than 1.0, RegD resources are paid too much. When the MBF is less than 1.0, each MW of RegD is worth less than 1.0 MW of RegA. The market design buys the correct amount of RegD, but pays RegD as if the MBF were 1.0. In an extreme case, when the MBF is 0.001, RegD MW are paid 1,000 times too much. If the market clearing price is $1.00 per MW of RegA, RegD is paid $1,000 per effective MW. Resolution of this problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the proposal finding it inconsistent with Order No. 755.

The MBF related issues with the regulation market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial solution to the RegD over procurement problem which was implemented on December 14, 2015. The interim solution was designed to reduce the relative value of RegD MW in all hours and to cap purchases of RegD MW during critical performance hours. But the interim solution did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Additional changes were implemented on January 9, 2017. These modifications included changing the definition of off peak and on peak hours, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15 minute neutrality requirement of the RegD signal to a 30 minute neutrality requirement.

The January 9, 2017, design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-36). These market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Table 10-36 Seasonal regulation requirement definitions[83]

Season	Dates	Nonramp Hours	Ramp Hours
		00:00 - 03:59	04:00 - 08:59
Winter	Dec 1 - Feb 28(29)	09:00 - 15:59	16:00 - 23:59
		00:00 - 04:59	05:00 - 07:59
Spring	Mar 1 - May 31	08:00 - 16:59	17:00 - 23:59
		00:00 - 04:59	05:00 - 13:59
Summer	Jun 1 - Aug 31	14:00 - 17:59	18:00 - 23:59
		00:00 - 04:59	05:00 - 07:59
Fall	Sep 1 - Nov 30	08:00 - 16:59	17:00 - 23:59

Performance Scores

Performance scores, by class and unit, are not an indicator of how well resources contribute to ACE control. Performance scores are an indicator only of how well the resources follow their TREG signal. High performance scores with poor signal design are not a meaningful measure of performance. For example, if ACE indicates the need for more regulation but RegD resources have provided all their available energy, the RegD regulation signal will be in the opposite direction of what is needed to control ACE. So, despite moving in the wrong direction for ACE control, RegD resources would get a good performance score for following the RegD signal and will be paid for moving in the wrong direction.

The RegD signal prior to January 9, 2017, is an example of a signal that resulted in high performance scores, but due to 15 minute energy neutrality built into the signal, ran counter to ACE control at times. Energy neutrality means that energy produced equals energy used within a defined timeframe. With 15 minute energy neutrality, if a battery were following the regulation signal to provide MWh for 7.5 minutes, it would have to consume the same amount of MWh for the next 7.5 minutes. When neutrality correction of the RegD signal is triggered, it overrides ACE control in favor of achieving zero net energy over the 15 minute period. When this occurs, the RegD signal runs counter to the control of ACE and hurts rather than helps ACE. In that situation, the control of ACE, which must also offset the negative impacts of RegD, depends entirely on RegA resources following the RegA signal. High performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January 9, 2017, design changes did not address the fundamental issues with the definition of performance or the nature of payments for performance in the regulation market design. The regulation signal should not be designed to favor a particular technology. The signal should be designed to result in the lowest cost of regulation to the market. Only with a performance score based on full substitutability among resource types should payments be based on following the signal. The MRTS must be redesigned to reflect the actual capabilities of technologies to provide regulation. The PJM regulation market design remains fundamentally flawed.

In addition, the absence of a performance penalty, imposed as a reduction in performance score and/or as a forfeiture of revenues, for deselection initiated by the resource owner within the hour, creates a possible gaming opportunity for resources which may overstate their capability to follow the regulation signal. The MMU recommends that there be a penalty enforced as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

Battery Settlement

The change from 15 to 30 minute signal neutrality, implemented in the January 9, 2017, design changes, resulted in the reduction of performance scores for short duration batteries. In April 2017 several participants filed a complaint against PJM, asserting that these changes discriminated against their battery units.[84] The MMU objected to the complaints. Despite the unsupported assertions in the complaint, PJM settled with the participants that was approved by FERC on April 7, 2020.[85] Table 10-37 shows the battery units that are part of the settlement. Starting July 1, 2020, the affected battery units began receiving compensation based on the greater of their current performance score, or their rolling average actual hourly performance score for the last 100 hours the resource operated prior to the January 9, 2017,

83 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

84 See FERC Docket Nos. EL17-64-000 and EL17-65-000.

85 See 170 FERC ¶ 61,258 (2020).

implementation of the 30-minute conditional neutrality. The additional regulation credits received in the first nine months of 2022 as a result of the settlement are shown in Table 10-38.

Table 10-37 Batteries in settlement

Parent Company	Unit	MW
The AES Corporation	Laurel Mountain	32.0
	Warrior Run	10.0
Energy Capital Partners, LLC	Hazel	20.0
Galt Power, Inc.	Trent	4.0
	McHenry	20.0
	Beckjord 1	2.0
	Beckjord 2	2.0
Invenergy, LLC	Beech Ridge	31.5
	Grand Ridge 6	4.5
	Grand Ridge 7	31.5
NextEra Energy, Inc.	Lee Dekalb	20.0
	Garrett	10.4
	Meyersdale	18.0
	Mantua Creek	2.0
Renewable Energy Systems Holdings, LTD	Joliet	20.0
	West Chicago	20.0
Sumitomo Corporation	Willey	6.0

Table 10-38 Excess regulation credits received by settlement batteries: January through September, 2022

Month	Excess Regulation Credit ($)
Jan	$230,764
Feb	$84,963
Mar	$70,375
Apr	$128,896
May	$104,817
Jun	$179,703
Jul	$160,327
Aug	$216,929
Sep	$169,958
Total	$1,346,731

In addition to paying uneconomic regulation credits based on inflated performance scores, the settlement also requires that the affected battery units be cleared in the regulation market regardless of whether their offer was economic. As long as the settlement batteries are offered as either self scheduled with a zero offer, or as a zero priced offer, they must be cleared despite the fact that these units would not necessarily have cleared based on economics.[86] In order to comply with this condition, PJM clears additional MW beyond what is needed for the regulation requirement in cases where the settlement battery units did not clear but met the offer rules of the settlement. This results in excess charges to customers for regulation service. Table 10-39 shows the impact of clearing additional MW beyond what is needed for the regulation requirement, as a result of the battery settlement, in the first nine months of 2022. Other changes in market dynamics starting in the third quarter of 2021 reduced the impact of this settlement rule because most of the settlement units clear based on economics. In the first nine months of 2022, the battery settlement resulted in customers paying $97,634 more than needed, in order to compensate the additional MW from settlement batteries that would not have otherwise cleared. As a result of the battery settlement, PJM customers in the first nine months of 2022 over paid for regulation by $1.4 million (the sum of Table 10-38 and Table 10-39).

Table 10-39 Excess payments and MW cleared due to battery settlement: January through September, 2022

	Battery Settlement Impact	
Month	Regulation Credits	Additional Cleared Regulation MW
Jan	$3,576	54.5
Feb	$9,974	384.3
Mar	$43,880	833.3
Apr	$829	24.7
May	$4,056	78.9
Jun	$904	33.5
Jul	$10,454	240.9
Aug	$10,487	234.9
Sep	$13,474	182.8
Total	$97,634	2,067.7

Regulation Signal

As with any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow their signals, including conditions under which neutrality cannot be maintained by RegD resources. The ability of energy limited RegD to provide ACE control

86 See *id.* at P 17.

depends on the availability of excess RegA capability to support RegD under the conditional neutrality design. When RegD resources are largely energy limited resources, a correctly calculated MBF would exhibit a rapid decrease in the MBF value for every MW of RegD added. The result is that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

Marginal Benefit Factor Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[87]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. This over procurement has degraded the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

PJM and the MMU filed a joint proposal with FERC on October 17, 2017, to address issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market, but the proposal was rejected by FERC.[88]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market prior to the December 14, 2015, changes did not accurately reflect the MRTS between RegA and RegD resources under the old market design, and it does not accurately reflect the MRTS between RegA and RegD resources under the current design. The MBF function is incorrectly defined and improperly implemented in the current PJM Regulation Market.

The MBF should be the marginal rate of technical substitution between RegA and RegD MW at different, feasible combinations of RegA and RegD that can be used to provide a defined level of regulation service. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will not represent the least cost solution and may not be a feasible way to reach the target level of regulation.

The MBF is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM implemented a FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the MBF entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[89] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality

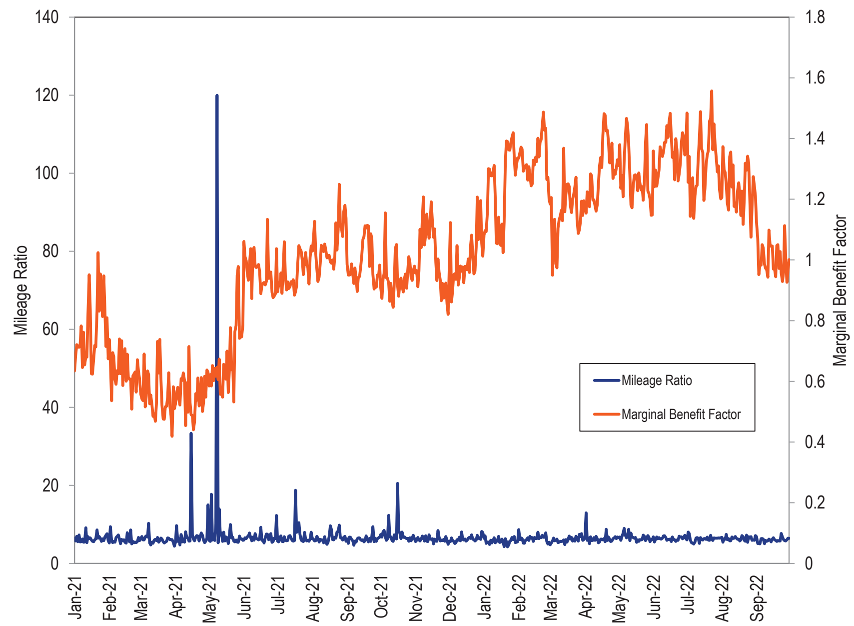
87 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.
88 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
89 145 FERC ¶ 61,011 (2013).

component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, some RegD resources decreased their offered capability to maintain their performance.

Figure 10-10 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio decreased from 7.06 in the first nine months of 2021, to 6.25 in the first nine months of 2022 (a decrease of 11.4 percent). The average MBF increased from 0.79 in the first nine months of 2021, to 1.25 in the first nine months of 2022 (an increase of 56.8 percent). The high mileage ratios are the result of the mechanics of the mileage ratio calculation. Extreme mileage ratios result when the RegA signal is fixed at a single value (pegged) to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

These results are an example of why it is not appropriate to use the mileage ratio, rather than the MBF, to measure the relative value of RegA and RegD resources. In these events, RegA resources are providing ACE control by providing a fixed level of MW output which means zero mileage, while RegD resources alternate between helping and hurting ACE control, both of which result in positive mileage.

Figure 10-10 Daily average MBF and mileage ratio: January 2021 through September 2022



The increase in the average mileage ratio caused by the signal design changes introduced on January 9, 2017, caused a large increase in payments to RegD resources on a performance adjusted MW basis.

Table 10-40 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2021, through September 30, 2022. The average regulation market clearing price in the first nine months of 2022 was $30.13 higher than in the first nine months of 2021 (See Table 10-54.) In the first nine months of 2022, RegD resources earned 17.0 percent more per performance adjusted actual MW than RegA resources (21.7 percent in the first nine months of 2021) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-40 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2021 through September 2022

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2021	Jan	$14.29	$11.43	25.1%
	Feb	$23.87	$19.90	19.9%
	Mar	$20.81	$17.93	16.0%
	Apr	$20.86	$16.73	24.6%
	May	$20.22	$16.42	23.2%
	Jun	$23.01	$18.40	25.1%
	Jul	$24.09	$19.34	24.6%
	Aug	$37.86	$31.77	19.2%
	Sep	$34.62	$28.59	21.1%
	Oct	$46.15	$38.91	18.6%
	Nov	$61.59	$52.92	16.4%
	Dec	$33.56	$26.85	25.0%
Yearly		$30.08	$24.93	20.7%
2022	Jan	$74.63	$68.59	8.8%
	Feb	$39.28	$31.51	24.6%
	Mar	$33.90	$25.56	32.6%
	Apr	$60.31	$49.00	23.1%
	May	$49.81	$41.57	19.8%
	Jun	$63.28	$54.47	16.2%
	Jul	$60.45	$53.40	13.2%
	Aug	$71.87	$63.64	12.9%
	Sep	$55.22	$46.90	17.7%
Yearly		$56.69	$48.46	17.0%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was greater than 1.0 in the first nine months of 2022 (1.25).

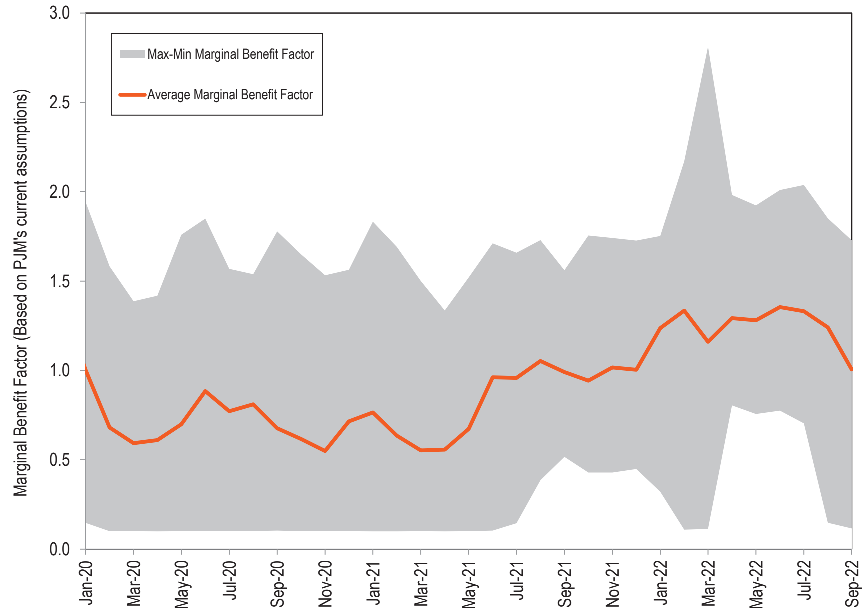
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-41. Table 10-41 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in the first nine months of 2021 and 2022 under the current rules, compared to how much RegD resources should have been paid if they were actually paid for effective MW. Using the MBF consistently throughout the PJM regulation market would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. However, the PJM regulation market only uses the MBF in the market clearing and setting of price on a dollar per effective MW basis, it does not use the MBF to convert RegD MW into effective MW for purposes of settlement. Because the MBF is not used to convert RegD MW into effective MW for purposes settlement, RegD resources are paid the dollar per effective MW price, but this is paid for performance adjusted MW, not for effective MW. This causes the MW value of RegD resources to be inflated in settlement when the MBF is less than one and to be undervalued in settlement when the MBF is greater than one. In the first nine months of 2022, the MBF averaged 1.25, while the average daily mileage ratio was 6.25, resulting in RegD resources being paid $6.4 million less than they would have been paid on an effective MW basis if the MBF were correctly implemented. In the first nine months of 2021, the MBF averaged 0.79, and the average mileage ratio was 7.06, resulting in RegD resources being paid $7.4 million more than they would have been paid if the MBF were correctly implemented. The shift from overpayment to underpayment of RegD resources between 2021 and the first nine months of 2022 is the result of an incorrect calculation of the MBF, as a result of the way dual offers are handled by PJM. This error has led to a decrease in the amount of RegD cleared and a resulting increase in the MBF of RegD resources. The higher MBF values have not been accurately reflected in prices.

Table 10-41 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2021 through September 2022

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment ($/Effective MW)	Total RegD Overpayment ($)
2021	Jan	$30.47	$11.43	$11.43	166.6%	$558,397
	Feb	$88.91	$19.90	$19.90	346.7%	$1,310,279
	Mar	$61.03	$17.93	$17.93	240.4%	$1,277,850
	Apr	$65.99	$16.73	$16.73	294.3%	$1,492,094
	May	$39.55	$16.42	$16.42	140.9%	$1,081,445
	Jun	$26.57	$18.40	$18.40	44.4%	$457,543
	Jul	$27.36	$19.34	$19.34	41.5%	$513,073
	Aug	$38.23	$31.77	$31.77	20.4%	$288,112
	Sep	$35.63	$28.59	$28.59	24.6%	$410,694
	Oct	$51.13	$38.91	$38.91	31.4%	$688,515
	Nov	$63.20	$52.92	$52.92	19.4%	$377,458
	Dec	$33.94	$26.85	$26.85	26.4%	$399,675
Yearly		$46.48	$24.93	$24.93	86.4%	$8,855,253
2022	Jan	$62.73	$68.59	$68.59	(8.5%)	($1,580,376)
	Feb	$29.38	$31.51	$31.51	(6.8%)	($516,687)
	Mar	$31.86	$25.56	$25.56	24.7%	$281,052
	Apr	$46.90	$49.00	$49.00	(4.3%)	($550,585)
	May	$39.30	$41.57	$41.57	(5.4%)	($582,040)
	Jun	$47.78	$54.47	$54.47	(12.3%)	($1,133,591)
	Jul	$45.45	$53.40	$53.40	(14.9%)	($1,438,918)
	Aug	$60.51	$63.64	$63.64	(4.9%)	($1,069,872)
	Sep	$55.46	$46.90	$46.90	18.2%	$239,007
Yearly		$46.75	$48.46	$48.46	(3.5%)	($6,352,011)

Figure 10-11 shows, the monthly maximum, minimum and average MBF, for January 2020 through September 2022. The average daily MBF in the first nine months of 2022 was 1.25. The average daily MBF in the first nine months of 2021 was 0.79. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1. The large increase in the maximum and average MBF is due to an incorrect calculation of the MBF, as a result of the way dual offers are handled by PJM. This error has led to a decrease in the amount of RegD cleared, and an increase in the MBF.

Figure 10-11 Maximum, minimum, and average PJM calculated MBF by month: January 2020 through September 2022



The MMU recommends that the regulation market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[90]

The overpayment of RegD has resulted in offers from RegD resources that are almost all at an effective cost of $0.00 ($0.00 offers plus self scheduled offers). RegD MW providers are ensured that such offers will clear and will be paid a price determined by the offers of RegA resources. This is evidence of the impact of the flaws in the clearing engine and the overpayment of RegD resources on the offer behavior of RegD resources.

Table 10-42 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2021

90 See "Regulation Market Review," Operating Committee (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

through September 2022. In the first nine months of 2022, an average of 96.0 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first nine months of 2021, an average of 99.0 percent of all cleared RegD MW had an effective cost of $0.00. In the first nine months of 2022, an average of 58.5 percent of all RegD offers were self scheduled, compared to an average of 72.9 percent of all RegD offers in the first nine months of 2021.

The high percentage of self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared along with the zero cost offers in the market clearing engine. However, unlike zero cost offers, self scheduled offers do not risk having an LOC added to their offer during the market clearing process, ensuring that self scheduled offers have a zero cost during market clearing. Given the increasing saturation of the regulation market with RegD MW, specifically demand response and battery units which do not receive LOC, market participants eligible for LOC that offer at zero instead of self scheduling, run the risk of an LOC added to their offer, and thus not clearing the market.

The average monthly RegD cleared in the market decreased 35.8 MW (19.0 percent), from 188.6 MW in the first nine months of 2021 to 152.8 MW in the first nine months of 2022. The average monthly RegD cleared with an effective cost of zero decreased 40.2 MW (21.5 percent), from 186.8 MW in the first nine months of 2021 to 146.7 MW in the first nine months of 2022. Self scheduled RegD cleared MW decreased 48.5 MW (35.2 percent), from 137.9 MW in the first nine months of 2021 to 89.4 MW in the first nine months of 2022. Average cleared RegD MW with a zero cost offer increased 8.3 MW (17.1 percent), from 48.9 MW in the first nine months of 2021 to 57.3 MW in the first nine months of 2022. The incorrect way that dual offers are offered and cleared in the regulation market has led to the decrease in the average monthly RegD cleared and the increase in the average monthly MBF seen in Figure 10-11.

Table 10-42 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2021 through September 2022

		Average Performance Adjusted Cleared RegD MW						
Year	Month	$0.00 Offer	$0.00 Offer Percent of Total	Self Scheduled	Self Scheduled Percentage of Total	Total Effective Cost of Zero	Effective Cost of Zero Percentage of Total	Total
2021	Jan	49.6	26.1%	139.9	73.7%	189.6	99.9%	189.8
	Feb	52.4	25.6%	152.3	74.4%	204.7	100.0%	204.7
	Mar	47.2	23.3%	155.4	76.7%	202.6	100.0%	202.6
	Apr	48.6	24.0%	154.0	76.0%	202.7	100.0%	202.7
	May	47.5	24.8%	143.8	75.0%	191.3	99.9%	191.6
	Jun	45.8	25.2%	133.3	73.4%	179.2	98.6%	181.7
	Jul	48.4	26.4%	130.7	71.4%	179.1	97.8%	183.1
	Aug	49.9	28.4%	120.8	68.6%	170.8	97.0%	176.0
	Sep	50.8	30.6%	111.1	67.1%	161.8	97.7%	165.6
	Oct	50.6	30.2%	114.6	68.3%	165.3	98.5%	167.7
	Nov	50.2	30.6%	109.0	66.5%	159.2	97.1%	164.0
	Dec	49.4	28.6%	118.0	68.2%	167.5	96.8%	173.0
Yearly		49.2	26.8%	131.8	71.9%	181.0	98.7%	183.4
2022	Jan	51.8	33.8%	95.5	62.2%	147.4	96.0%	153.5
	Feb	59.6	40.6%	84.1	57.2%	143.8	97.8%	147.0
	Mar	59.7	38.2%	93.3	59.7%	153.0	98.0%	156.2
	Apr	52.9	36.8%	84.3	58.5%	137.2	95.3%	144.0
	May	52.5	37.0%	85.7	60.4%	138.1	97.4%	141.8
	Jun	51.6	34.1%	89.2	59.0%	140.8	93.1%	151.2
	Jul	59.9	38.4%	84.9	54.4%	144.8	92.8%	156.1
	Aug	62.1	38.6%	92.2	57.3%	154.4	95.9%	160.9
	Sep	65.2	39.6%	95.2	57.9%	160.5	97.5%	164.6
Yearly		57.3	37.5%	89.4	58.5%	146.7	96.0%	152.9

Incorrect MBF and total effective MW when clearing units with dual product offers

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer is incorrect and leads to solutions that are not the most economic. The result of the flaw is that the MBF in the regulation market clearing phase is incorrectly low compared to the MBF in the market solution phase, too little RegD is cleared relative to the efficient amount, the RegD resources that do clear are underpaid when the resulting MBF is greater than 1.0 and the actual amount of effective MW procured is higher than the regulation requirement.

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of the dual offers would provide the least cost solution. But this is not how PJM clears the regulation market when there are dual offer units. PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously, and assigns every RegD resource, including dual offer resources, a unit specific benefit factor.

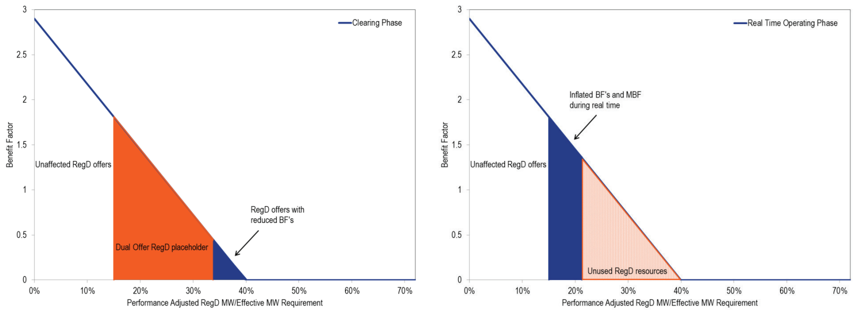
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. The placeholder RegD MW from the dual offer should be removed, the cleared MW from below the placeholder should be shifted up the supply/MBF curve, and additional RegD MW offers that were pushed below an MBF of zero and initially not included, should be considered. But PJM does not recalculate the MBF values for the remaining RegD resources when determining the cleared effective MW needed to satisfy the regulation requirement during the clearing phase. The result is that the MBF in the clearing phase is incorrectly low, and the actual amount of effective MW procured is higher.

After meeting the target effective MW to satisfy the regulation requirement for that hour through the clearing process, the unit specific benefit factors of those displaced units are recalculated in the real-time operating phase and increased based on their actual contribution. The effective MW contributions of those originally displaced units are correctly calculated in the operating phase, but because the supply for that hour has already been set based on their incorrect effective MW, the solution includes more effective MW than calculated in the clearing phase. As a result, the market solution includes more than the target level of effective MW in the actual operating hour.

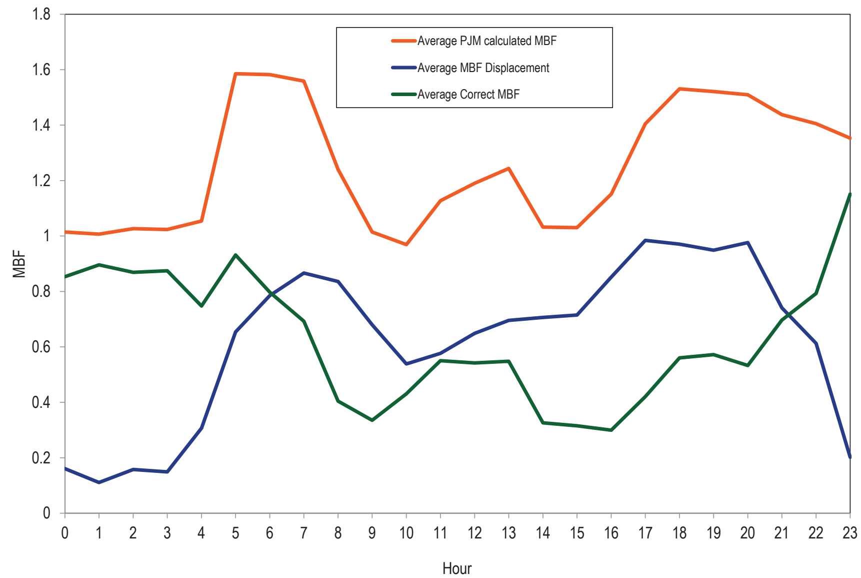
The issue is illustrated in Figure 10-12. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the curve in the clearing phase. The effective MW of the cleared RegD resources with higher effective costs are represented by the blue triangle in the clearing phase. Not shown are additional RegD MW with higher effective costs that were assigned an MBF of 0 and not cleared. The 150 MW dual offer unit is chosen to operate as a RegA resource in the operational hour. As a result, the cleared supply for RegA in the clearing phase is the same RegA supply realized in the real time operating phase. But that is not the case for the RegD supply. Since the supply curve and unit specific benefit factors of RegD MW are not recalculated in the clearing phase after the 150 MW RegD offer is removed, the amount of effective MW realized in the real-time operating phase is inconsistent with the clearing phase. Because the RegD portion of the 150 MW dual offer unit was not chosen to be RegD MW, the RegD resources represented by the blue triangle in the clearing phase will contribute more effective MW (the blue area in the real-time solution phase) in the real-time solution phase than was assumed in the clearing phase because the MBF in the clearing phase was too low. Since the blue area under the curve in the real-time solution phase is greater than the blue area in the clearing phase and the amount of RegA remains the same between the clearing phase and real-time operating phase, the market will have cleared too many effective MW relative to the effective MW requirement. The MBF in the operating phase is higher than if the clearing had been solved correctly.

Figure 10-12 Clearing phase BF/effective MW reduction, real-time BF/effective MW inflation, and exclusion of available RegD resources



In the first nine months of 2022, all hours had at least one unit with a dual offer. In the first nine months of 2022, 38.8 percent of all hours had at least one dual offer unit that was chosen to run as RegA, resulting in an average MBF increase of 0.78 in the operating phase. The average MBF increase due to dual offers clearing as RegA in the first nine months of 2021 was 0.48. This indicates that the amount of MW clearing as RegA from dual offers has increased, the amount of RegD clearing has been artificially reduced, resulting in higher MBF of RegD in the market solution in the first nine months of 2021. In the first nine months of 2022, 6,181 dual offers from generating units were cleared as RegA, an increase of 24.9 percent from the first nine months of 2021 (4,950 dual offers clearing as RegA). If the market had been cleared correctly, the correct average MBF would have been significantly lower in real time (operating phase), because additional RegD offers with lower benefit factors that were initially excluded, would have been included after the removal of the dual offer placeholder, reducing the MBF. Figure 10-13 illustrates the PJM calculated average MBF in real time (operating phase), the average amount the MBF is artificially increased (MBF displacement) due to dual offers clearing as RegA, and what the correct average MBF would have been in each hour of the day for the first nine months of 2022 if the clearing solution were solved correctly.

Figure 10-13 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: January through September, 2022



Absent the ability to correctly clear dual offers, the MMU recommends that the ability of resources to submit dual offers be removed. Under this revision to the rules, resources could offer as either RegA or RegD in a given hour, but not both within the same market hour.

Price Spikes

Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

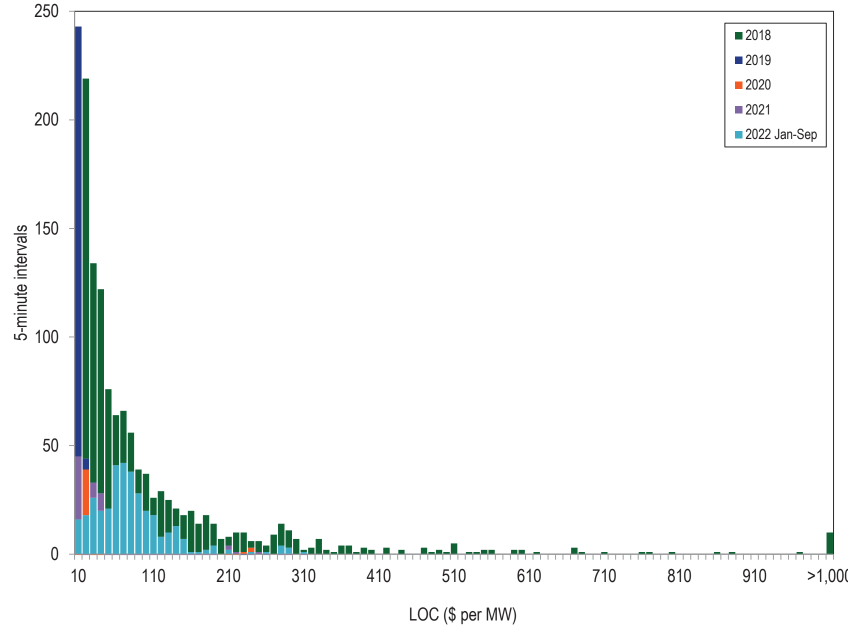
The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit is less than one (e.g. the marginal unit is a RegD unit), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) and the realized offer price of the resource in the actual market result. This will cause a significant price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. In January 2019, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[91] This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them.

Figure 10-14 shows the LOC in each five minute interval in which the marginal unit had a unit specific benefit factor less than one (e.g. a RegD unit) and the LOC was greater than zero from 2018 through September 2022.

91 See 166 FERC ¶ 61,040 (2019).

Figure 10-14 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2018 through September 2022



For a RegD resource to clear the regulation market with an MBF of 0.001, the resource's offer, in dollars per marginal effective MW, must be less than or equal to competing offers from RegA MW. A RegD offer of 1 MW with an MBF of 0.001 and a price of $1 per MW, would provide 0.001 effective MW at a price of $1,000 per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real-time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to use the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's Regulation Market are a symptom of a market failure in PJM's Regulation Market caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Uplift Calculation Issues

Regulation uplift is calculated by comparing a resource's regulation offer price plus its regulation lost opportunity cost (including shoulder LOC if applicable) adjusted by the performance score, to the clearing price credits the unit received.[92] If the sum of the resources offer plus LOC is greater than the amount of clearing price credits received, additional uplift credits are given equal to the difference.

The calculation of regulation uplift during settlements for coal and natural gas units is incorrect, and results in the overpayment of uplift.[93] In order to determine the amount of regulation uplift, the difference between the MW output of the unit while it was providing regulation is compared to the desired MW output of the unit if it had not provided regulation. The desired amount of MW output at LMP used in the calculation of regulation uplift during settlements is determined based on a unit's energy offer and the LMP during the interval being evaluated. But this desired MW does not account for the ability of a unit to actually produce the desired output because it does not take into account the physical limitations of the unit's ability to ramp. This results in the overpayment of uplift by paying for MW that the unit could not have produced given their energy market output at the beginning of the interval and their ramp rate.

Table 10-43 shows the amount of uplift overpayment by fuel type for the first nine months of 2022, as a result of the ramp rate not being used in the current calculation. The overpayments are calculated using a desired MW level that can be achieved based on the units' ramp rates. In the first nine months of 2022, overpayments totaled $23.7 million. Coal units received 45.2 percent of the overpayment while providing 5.5 percent of settled regulation MW.

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.

92 The clearing price for each interval is set by the marginal unit's total offer (capability and performance offers plus LOC), adjusted by the marginal unit's performance score, and does not include any shoulder LOC.

93 Hydro units operate on a schedule rather than an energy bid, therefore a different equation is used to calculate their regulation LOC and uplift. The issue discussed does not effect that calculation. Also, demand response and battery units do not receive uplift.

Table 10-43 Amount of LOC overpayment: January 2021 through September 2022

		Uplift overpayment		
Year	Month	Coal	Natural Gas	Total
2021	Jan	$189,413	$151,479	$340,892
	Feb	$362,280	$458,780	$821,059
	Mar	$213,908	$313,696	$527,604
	Apr	$409,813	$527,769	$937,582
	May	$384,659	$175,792	$560,451
	Jun	$387,173	$231,534	$618,707
	Jul	$152,339	$180,229	$332,568
	Aug	$135,911	$360,753	$496,664
	Sep	$217,114	$516,718	$733,833
	Oct	$137,579	$741,654	$879,233
	Nov	$926,402	$2,365,660	$3,292,061
	Dec	$327,458	$945,934	$1,273,392
Total		$3,844,048	$6,969,998	$10,814,046
2022	Jan	$1,959,942	$2,308,232	$4,268,174
	Feb	$432,077	$1,103,635	$1,535,711
	Mar	$297,947	$990,141	$1,288,088
	Apr	$1,447,659	$1,627,371	$3,075,030
	May	$625,195	$1,318,174	$1,943,369
	Jun	$752,995	$1,529,581	$2,282,575
	Jul	$2,816,672	$1,359,550	$4,176,222
	Aug	$1,945,760	$1,772,383	$3,718,143
	Sep	$409,138	$973,280	$1,382,418
Total		$10,687,385	$12,982,346	$23,669,731

Market Structure

Supply

Table 10-44 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first nine months of 2022.[94] Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.[95] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In the first nine months of 2022, the average hourly offered supply of regulation for nonramp hours was 757.5 actual MW (765.8 effective MW). This was an increase of 4.1 actual MW (an increase of 13.1 effective MW) from the first nine months of 2021, when the average hourly offered supply of regulation was 753.4 actual MW (752.8 effective MW). In the first nine months of 2022, the average hourly offered supply of regulation for ramp hours was 1,124.4 actual MW (1,127.6 effective MW). This was an increase of 47.9 actual 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 actual MW (1,101.7 effective MW).[96]

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual 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 (actual cleared MW) for ramp hours was 1.56 in the first nine months of 2022 (1.52 in the first nine months of 2021).

94 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve.

95 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).

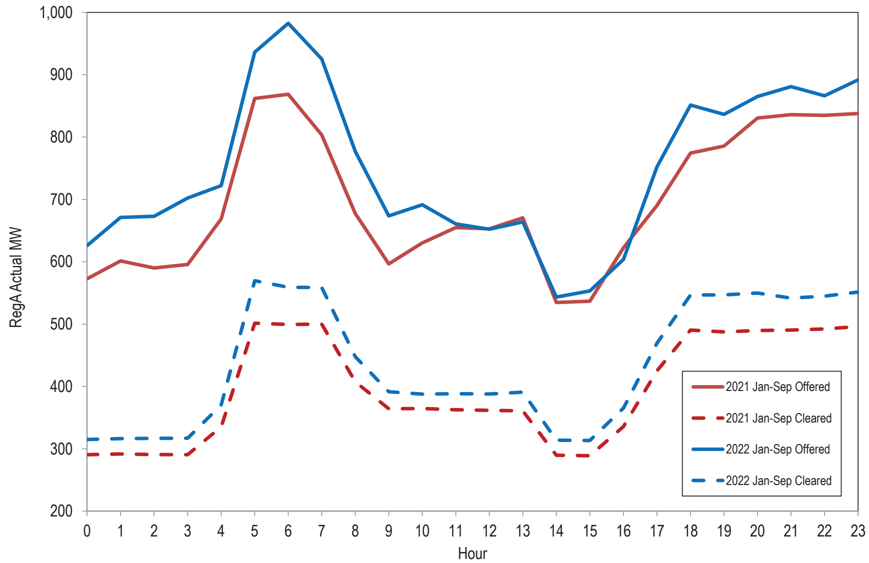
96 Effective MW equal actual MW multiplied by the performance score and benefit factor for each unit. In the case of RegA, the benefit factor is always equal to one, and performance scores are always less than one, so effective MW of RegA are less than actual MW. For RegD resources effective MW can be larger than actual MW, if the benefit factor is greater than one. When adding RegA and RegD total MW together, actual MW can be larger or smaller than effective MW, depending on the influence of RegA MW and RegD MW.

Table 10-44 Hourly average actual and effective MW offered and cleared: January through September, 2022[97]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,124.4	1,104.8	19.6	897.5	226.9
	Nonramp	757.5	743.5	14.1	594.2	163.3
Effective Offered MW	Ramp	1,127.6	1,098.7	29.0	766.8	360.9
	Nonramp	765.8	748.8	17.1	505.5	260.4
Actual Cleared MW	Ramp	718.9	699.3	19.6	551.5	167.4
	Nonramp	464.8	450.9	13.9	313.6	151.2
Effective Cleared MW	Ramp	800.0	771.1	28.9	474.8	325.2
	Nonramp	525.2	508.4	16.8	269.4	255.8

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-15. The average hourly offered MW from RegA resources during ramp hours for the first nine months of 2022 was 897.5 actual MW, an increase of 8.1 percent from the first nine months of 2021 (830.3 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for the first nine months of 2022 was 594.2 actual MW, an increase of 6.9 percent from the first nine months of 2021 (555.6 actual MW). The average hourly cleared MW from RegA resources during ramp hours for the first nine months of 2022 was 551.5 actual MW, an increase of 11.1 percent from the first nine months of 2021 (496.4 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first nine months of 2022 was 313.6 actual MW, an increase of 8.2 percent from the first nine months of 2021 (289.7 actual MW).

Figure 10-15 Average hourly RegA actual MW offered and cleared: January through September, 2021 through 2022[98]



The average hourly offered MW from RegD resources during ramp hours for the first nine months of 2022 was 226.9 actual MW, a decrease of 7.9 percent from the first nine months of 2021 (246.2 actual MW). (Figure 10-16) The average hourly offered MW from RegD resources during nonramp hours for the first nine months of 2022 was 163.3 actual MW, a decrease of 17.4 percent from the first nine months of 2021 (197.8 actual MW) (Figure 10-16). The average hourly cleared MW from RegD resources during ramp hours for the first nine months of 2022 was 167.4 actual MW, a decrease of 20.3 percent from the first nine months of 2021 (209.9 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first nine months of 2022 was 151.2 actual MW, a decrease of 23.0 percent from the first nine months of 2021 (196.3 actual MW).

97 PJM operations treats some nonramp hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW. All ramp/nonramp analysis performed is based on the requirement used in each hour rather than the definitions given in Table 10-2. A ramp hour occurring during what is normally a nonramp period is treated as a ramp hour.

98 Offered MW includes MW from units that are dual offering as both RegA and RegD.

Figure 10-16 Average hourly RegD actual MW offered and cleared: January through September, 2021 through 2022[99]

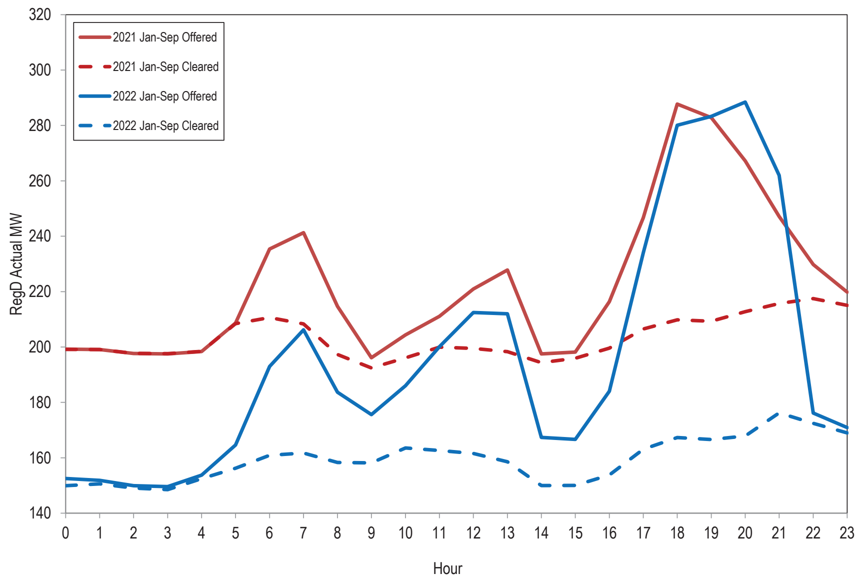


Table 10-46 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-46 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 2.0 percent from 3,476,601.8 MW in the first nine months of 2021 to 3,407,381.2 MW in the first nine months of 2022. The average proportion of regulation provided by natural gas units increased the most, by 10.0 percent from the first nine months of 2021 to the first nine months 2022. Battery units had the largest decrease in average proportion of regulation provided, decreasing 9.5 percent, from the first nine months of 2021 to the first nine months of 2022. The total regulation credits in the first nine months of 2022 were $211,778,160, an increase of 141.1 percent from $87,852,568 in the first nine months of 2021. The increase in regulation credits is due, in part, to a higher LOC component of regulation prices as a result of higher energy prices in the first nine months of 2022 compared to the first nine months of 2021.

When a resource offers into the regulation market, an estimated regulation LOC is added by PJM to form a total offer (units self scheduled or not providing in the energy market have a regulation LOC of zero). After a unit clears, the actual five minute interval LMP is used to calculate each unit's regulation LOC, update their total offers, and determine a marginal unit/clearing price in each five minute interval. This within hour calculation of total offers, including LOC, uses each cleared resource's rolling 100 hour average performance score. During settlements, each unit's regulation LOC and total offers are recalculated using each unit's within hour actual performance score. This recalculated LOC and offer using the actual within hour performance score is not used to recalculate the within hour clearing price. This means that the clearing price for the hour will not equal the correct clearing price. Where the resulting market price is lower than an individual resource offer adjusted for the within hour performance score, the resource is paid uplift to make up the difference.

The top ten units that received the most uplift in the first nine months of 2022 are shown in Table 10-45.

99 Offered MW includes MW from units that are dual offering as both RegA and RegD.

Table 10-45 Top 10 recipients of regulation uplift credits: January through September, 2022

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$1,689,152	5.9%
2	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$1,473,599	5.2%
3	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$1,316,448	4.6%
4	American Electric Power Company Inc	AEP AMOS 1 F	COAL	$1,217,607	4.3%
5	American Electric Power Company Inc	AEP BIG SANDY 1 F	NATURAL GAS	$1,083,635	3.8%
6	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$1,015,022	3.6%
7	American Electric Power Company Inc	AEP AMOS 2 F	COAL	$896,048	3.1%
8	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$883,179	3.1%
9	Ontario Power Generation Inc	AP LKLYN 1-4 H	HYDRO	$857,019	3.0%
10	American Municipal Power Inc	FE FREMONT ENERGY CENTER 3 CC	NATURAL GAS	$814,979	2.9%
Total of Top 10				$11,246,689	39.4%
Total Regulation Uplift Credits				$28,559,008	100.0%

The uplift credits received for each unit type are shown in Table 10-46. The total uplift credits received increased 217.0 percent from $9,010,280 in the first nine months of 2021 to $28,559,008 in the first nine months of 2022. This increase, like the increase in total credits, is due in part to higher LOC components of regulation prices and offers as a result of higher energy prices in the first nine months of 2022 compared to the first nine months of 2021. Coal units had the largest increase in uplift payments, increasing from $2,464,124 (29.2 percent of total uplift) in the first nine months of 2021, to $11,294,407 (39.5 percent of total uplift) in the first nine months of 2022.

Table 10-46 PJM regulation by source: January through September, 2021 and 2022[100]

Year (Jan-Sep)	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2021	Battery	23	1,186,261	34.1%	$28,722,356	$0	$28,722,356
	Coal	19	298,507	8.6%	$5,807,902	$2,464,124	$8,272,026
	Hydro	28	639,791	18.4%	$15,219,294	$2,628,568	$17,847,862
	Natural Gas	184	1,303,471	37.5%	$27,778,939	$3,917,589	$31,696,528
	DR	19	48,572	1.4%	$1,313,796	$0	$1,313,796
Total		273	3,476,601.8	100.0%	$78,842,288	$9,010,280	$87,852,568
2022	Battery	21	837,450	24.6%	$47,874,499	$0	$47,874,499
	Coal	17	188,124	5.5%	$12,243,762	$11,294,407	$23,538,169
	Hydro	24	668,383	19.6%	$39,502,288	$4,361,532	$43,863,821
	Natural Gas	141	1,617,032	47.5%	$77,884,270	$12,903,068	$90,787,339
	DR	21	96,392	2.8%	$5,714,333	$0	$5,714,333
Total		224	3,407,381.2	100.0%	$183,219,152	$28,559,008	$211,778,160

100 Biomass data have been added to the natural gas category for confidentiality purposes.

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have contributed to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-47).

Table 10-47 Active battery storage projects by submitted year: 2014 through September 2022

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	5	61.0
2016	0	0.0
2017	1	2.0
2018	16	600.1
2019	55	3,609.4
2020	153	9,458.9
2021	312	24,282.1
2022	106	11,472.5
Total	649	49,496.0

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the first nine months of 2022 retire, the supply of regulation in PJM will be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp hours (Table 10-36).

Table 10-48 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. Changes in the actual MW required to satisfy the regulation requirement are the result of the amount of RegD actual MW cleared. When more RegD MW are cleared, the MBF is lower, resulting in those actual MW being worth less effective MW, requiring more actual MW to satisfy the requirement. When MBFs are higher, the actual MW of RegD are worth more effective MW, reducing the amount of actual MW needed to satisfy the requirement.

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 a decrease 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.[101]

101 The supply of performance adjusted MW is less than the demand because the regulation requirement is based on effective MW. Effective MW are performance adjusted MW multiplied by the MBF, and the average MBF in the first nine months of 2022 was 1.25.

Table 10-48 Required regulation and ratio of supply to requirement: January 2021 through September 2022

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	2021	2022	2021	2022	2021	2022	2021	2022
Ramp	Jan	713.2	720.6	800.0	800.0	1.59	1.51	1.42	1.37
	Feb	709.7	729.4	800.0	800.0	1.53	1.71	1.37	1.52
	Mar	713.8	723.0	800.0	800.0	1.54	1.54	1.38	1.39
	Apr	702.8	729.3	800.0	800.0	1.48	1.47	1.33	1.34
	May	705.5	720.2	800.0	800.0	1.45	1.54	1.32	1.38
	Jun	698.8	714.4	799.9	800.0	1.50	1.60	1.36	1.44
	Jul	699.0	720.3	799.9	800.0	1.54	1.55	1.38	1.40
	Aug	707.4	710.9	800.0	800.0	1.58	1.60	1.43	1.43
	Sep	710.7	704.3	800.0	800.0	1.47	1.53	1.35	1.38
	Oct	712.9	-	799.9	-	1.44	-	1.32	-
	Nov	708.4	-	800.0	-	1.41	-	1.30	-
	Dec	705.7	-	799.9	-	1.51	-	1.38	-
Nonramp	Jan	495.1	467.4	525.2	525.0	1.52	1.62	1.42	1.45
	Feb	500.4	466.9	525.1	525.0	1.59	1.78	1.47	1.56
	Mar	495.9	468.8	525.2	525.1	1.59	1.63	1.47	1.46
	Apr	490.9	469.1	525.1	525.1	1.51	1.56	1.41	1.41
	May	487.1	461.5	525.5	525.3	1.54	1.60	1.43	1.43
	Jun	478.6	459.6	525.4	525.8	1.50	1.66	1.39	1.48
	Jul	475.5	459.9	525.1	525.1	1.51	1.64	1.40	1.47
	Aug	474.4	461.3	525.2	525.3	1.60	1.65	1.47	1.48
	Sep	470.9	465.0	525.1	525.2	1.58	1.59	1.44	1.43
	Oct	471.8	-	525.1	-	1.51	-	1.39	-
	Nov	468.8	-	525.0	-	1.45	-	1.34	-
	Dec	469.5	-	525.0	-	1.57	-	1.42	-

Market Concentration

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. The weighted average HHI reflects the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-49 includes a monthly summary of three pivotal supplier (TPS) results. In the first nine months of 2022, the three pivotal supplier test was failed in 88.8 percent of hours. The MMU concludes that the PJM Regulation Market in the first nine months of 2022 was characterized by structural market power. The results presented here are calculated by PJM. The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations are not saved. PJM has submitted a request to the vendor to save all data necessary for verification.

Table 10-49 Regulation market monthly three pivotal supplier results: January 2020 through September 2022

	Percent of Hours Pivotal		
Month	2020	2021	2022
Jan	99.1%	91.4%	94.5%
Feb	97.4%	88.7%	84.1%
Mar	98.3%	87.2%	90.1%
Apr	96.5%	88.5%	92.8%
May	94.9%	83.9%	91.4%
Jun	89.8%	86.4%	85.7%
Jul	89.0%	86.4%	88.2%
Aug	94.6%	76.3%	86.4%
Sep	93.3%	82.9%	86.1%
Oct	94.0%	91.9%	
Nov	91.0%	86.7%	
Dec	83.6%	80.1%	
Average	93.5%	85.9%	88.8%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[102] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100 per MW) by 14:15 the day before the operating day.[103]

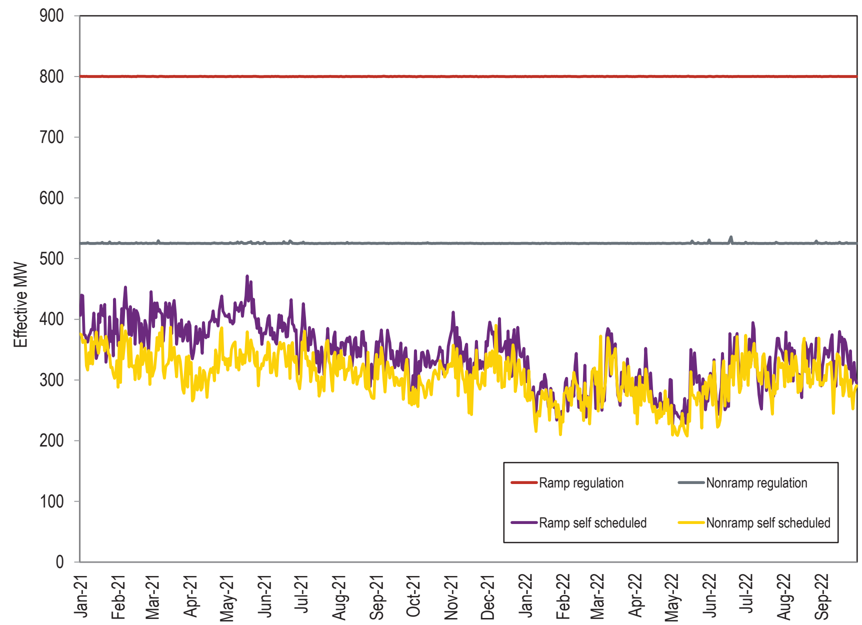
102 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).
103 Id. at 3.2.2, at p 62.

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers, is not part of the cost of regulation, and should be eliminated. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[104]

Up until one hour before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[105]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-52).[106] Figure 10-17 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. Self scheduled regulation averaged 37.8 percent of all effective MW during ramp hours (47.1 percent in the first nine months of 2021) and 54.5 percent of all effective MW during nonramp hours (62.1 percent in the first nine months of 2021) in the first nine months of 2022. Over all hours in the first nine months of 2022, self scheduled regulation averaged 44.4 percent of all effective MW (53.0 percent in the first nine months of 2021) (See Table 10-50). The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[107]

Figure 10-17 Nonramp and ramp regulation levels: January 2021 through September 2022



104 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 41 (Oct. 1, 2022).
105 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).
106 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 88 (OCT. 1, 2022).
107 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).

Table 10-50 Total Effective MW and Self Scheduled Effective MW during ramp and non ramp hours: January through September, 2021 and 2022.

Year (Jan-Sep)		Effective MW	Self Scheduled Effective MW	Percent Effective MW
2021	Ramp	218,394.7	102,880.5	47.1%
	Non Ramp	143,385.2	89,030.7	62.1%
Total		361,779.9	191,911.2	53.0%
2022	Ramp	218,400.6	82,451.2	37.8%
	Non Ramp	143,382.8	78,209.5	54.5%
Total		361,783.4	160,660.7	44.4%

Table 10-51 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 46.9 percent of the total effective MW in September 2022) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 62.5 percent of all self scheduled effective MW in September 2022). In the first nine months of 2022, the average RegD percentage of total self scheduled effective MW was 67.9 percent, a decrease of 4.3 percentage points from the first nine months of 2021, when the average was 72.2 percent.

Table 10-51 RegD self scheduled regulation by month: January 2021 through September 2022

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2021	Jan	250.5	322.4	367.7	674.0	68.1%	47.8%
2021	Feb	262.0	335.3	366.7	674.3	71.4%	49.7%
2021	Mar	263.0	321.7	359.0	639.9	73.3%	50.3%
2021	Apr	266.0	325.9	343.1	639.6	77.5%	51.0%
2021	May	256.8	320.6	368.0	639.9	69.8%	50.1%
2021	Jun	266.5	329.9	362.7	697.0	73.5%	47.3%
2021	Jul	255.4	331.6	344.6	696.9	74.1%	47.6%
2021	Aug	242.6	326.1	330.2	698.9	73.5%	46.7%
2021	Sep	219.8	302.0	319.6	639.6	68.8%	47.2%
2021	Oct	223.6	301.0	311.1	639.8	71.9%	47.1%
2021	Nov	218.5	298.9	321.2	640.3	68.0%	46.7%
2021	Dec	239.3	316.3	341.4	673.9	70.1%	46.9%
2021 Average		247.0	332.0	344.6	662.8	71.7%	48.2%
2022	Jan	211.8	295.7	267.8	674.0	79.1%	43.9%
2022	Feb	193.7	285.2	278.7	674.0	69.5%	42.3%
2022	Mar	202.1	285.3	305.6	639.8	66.1%	44.6%
2022	Apr	191.5	274.9	270.0	639.6	70.9%	43.0%
2022	May	191.2	276.4	258.3	639.8	74.0%	43.2%
2022	Jun	201.5	296.7	302.4	697.2	66.6%	42.6%
2022	Jul	192.7	299.8	321.1	696.9	60.0%	43.0%
2022	Aug	205.6	308.3	328.0	697.0	62.7%	44.2%
2022	Sep	196.4	300.0	314.3	639.3	62.5%	46.9%
2022 Average		198.5	291.4	294.0	666.4	67.9%	43.7%

LSE's can satisfy their obligation to provide regulation by purchasing in the spot market, self scheduling, or through bilateral agreements. Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first nine months of 2022, 56.0 percent was purchased in the PJM market, 36.0 percent was self scheduled, and 8.0 percent was purchased bilaterally (Table 10-52). Table 10-53 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for January through September, 2012 through 2022. Table 10-52 and Table 10-53 are based on settled (purchased) MW.

Table 10-52 Regulation sources: spot market, self scheduled, bilateral purchases: January 2021 through September 2022

Year	Month	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2021	Jan	186,762.8	46.6%	192,708.2	48.1%	21,466.0	5.4%	400,937.0
2021	Feb	172,967.1	47.4%	174,470.7	47.9%	17,095.5	4.7%	364,533.3
2021	Mar	182,812.8	47.3%	189,176.1	48.9%	14,910.0	3.9%	386,898.9
2021	Apr	190,444.5	51.0%	170,255.4	45.6%	12,763.0	3.4%	373,462.9
2021	May	171,841.5	44.5%	198,026.9	51.3%	16,270.0	4.2%	386,138.5
2021	Jun	211,800.7	54.2%	163,167.4	41.8%	15,526.0	4.0%	390,494.1
2021	Jul	225,587.1	55.9%	162,774.7	40.4%	15,017.5	3.7%	403,379.4
2021	Aug	234,148.0	57.9%	154,435.7	38.2%	15,577.5	3.9%	404,161.2
2021	Sep	190,656.5	53.7%	150,785.2	42.4%	13,896.0	3.9%	355,337.7
2021	Oct	212,564.6	57.0%	150,788.9	40.4%	9,873.5	2.6%	373,226.9
2021	Nov	191,647.2	53.7%	151,450.1	42.4%	13,883.0	3.9%	356,980.3
2021	Dec	211,012.8	54.1%	164,679.9	42.2%	14,258.5	3.7%	389,951.2
Total		2,382,245.5	52.0%	2,022,719.3	44.1%	180,536.5	3.9%	4,585,501.3
2022	Jan	257,948.1	67.0%	110,706.4	28.8%	16,315.0	4.2%	384,969.5
2022	Feb	220,778.9	63.1%	113,317.3	32.4%	15,659.5	4.5%	349,755.8
2022	Mar	208,538.9	56.8%	145,113.8	39.5%	13,349.5	3.6%	367,002.2
2022	Apr	215,631.5	60.6%	116,433.1	32.7%	23,836.0	6.7%	355,900.6
2022	May	219,531.8	60.8%	111,742.8	31.0%	29,596.0	8.2%	360,870.6
2022	Jun	217,223.5	56.4%	134,779.2	35.0%	32,944.0	8.6%	384,946.7
2022	Jul	188,416.3	47.5%	158,033.3	39.8%	50,157.0	12.6%	396,606.5
2022	Aug	193,928.6	49.6%	158,307.5	40.5%	38,824.0	9.9%	391,060.2
2022	Sep	148,455.0	42.8%	153,563.6	44.3%	44,869.0	12.9%	346,887.7
Total		1,870,452.6	56.0%	1,201,997.0	36.0%	265,550.0	8.0%	3,337,999.7

Table 10-53 Regulation sources: January through September, 2012 through 2022

Year (Jan-Sep)	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2012	5,110,747.9	79.7%	1,122,671.9	17.5%	180,121.0	2.8%	6,413,540.8
2013	2,528,830.3	60.8%	1,478,608.5	35.5%	152,328.5	3.7%	4,159,767.3
2014	1,836,488.7	51.8%	1,543,266.0	43.5%	166,857.0	4.7%	3,546,611.7
2015	1,897,225.7	54.7%	1,380,004.7	39.8%	193,529.1	5.6%	3,470,759.5
2016	1,672,795.5	47.8%	1,598,231.6	45.7%	226,803.5	6.5%	3,497,830.6
2017	1,849,333.5	54.1%	1,372,996.2	40.2%	196,759.5	5.8%	3,419,089.2
2018	2,124,551.1	61.8%	1,135,540.8	33.0%	178,593.5	5.2%	3,438,685.4
2019	1,755,035.5	52.6%	1,405,707.9	42.2%	174,186.0	5.2%	3,334,929.4
2020	1,608,960.6	46.7%	1,667,128.2	48.3%	172,159.5	5.0%	3,448,248.3
2021	1,766,633.1	51.0%	1,555,694.7	44.9%	142,521.5	4.1%	3,464,849.2
2022	1,870,452.6	56.0%	1,201,997.0	36.0%	265,550.0	8.0%	3,337,999.7

In the first nine months of 2022, DR provided an average of 19.6 MW of regulation per hour during ramp hours (10.3 MW of regulation per hour during ramp hours in the first nine months of 2021), and an average of 13.9 MW of regulation per hour during nonramp hours (6.9 MW of regulation per hour during nonramp hours in the first nine months of 2021). Generating units supplied an average of 699.3 MW of regulation per hour during ramp hours in the first nine months of 2022 (696.0 MW of regulation per hour during ramp hours in the first nine months of 2021), and an average of 450.9 MW per hour during nonramp hours in the first nine months of 2022 (479.1 MW of regulation per hour during nonramp hours in the first nine months of 2021).

Market Performance

Price

Table 10-54 shows the regulation price and regulation cost per MW for January through September, 2009 through 2022. The weighted average RMCP for the first nine months of 2022 was $51.04 per MW. This is an increase of $30.13 per MW, or 144.1 percent, from the weighted average RMCP of $20.91 per MW in the first nine months of 2021. This increase in the regulation clearing price was the result of an increase in energy prices in the first nine months of 2022 and the related increase in the opportunity cost component of RMCP.

Table 10-54 Comparison of average price and cost for regulation: January through September, 2009 through 2022

Year (Jan-Sep)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$24.94	$32.28	77.3%
2010	$19.47	$34.54	56.4%
2011	$17.04	$32.70	52.1%
2012	$15.16	$21.07	71.9%
2013	$33.29	$38.49	86.5%
2014	$50.19	$60.94	82.4%
2015	$35.56	$43.00	82.7%
2016	$16.52	$18.99	87.0%
2017	$15.70	$21.70	72.4%
2018	$28.21	$35.06	80.5%
2019	$14.97	$19.15	78.1%
2020	$12.59	$15.59	80.8%
2021	$20.91	$25.37	82.4%
2022	$51.04	$63.46	80.4%

The introduction of fast start pricing in the PJM energy market on September 1, 2021, had an effect on the regulation market LOC included in regulation offers and in the resulting clearing price for regulation. Table 10-55 shows the effect of fast start pricing on the regulation market monthly capability component of price and the total regulation market clearing price from September 2021 through September, 2022. In the first nine months of 2022, fast start pricing increased the average regulation market clearing price by 8.4 percent compared to dispatch pricing.

Table 10-55 Comparison of fast start and dispatch pricing: September 2021 through September 2022[108]

		Weighted Average Price ($/Perf. Adj. Actual MW)				
		Capability Clearing Price		Regulation Market Clearing Price		
Year	Month	Dispatch	Fast Start	Dispatch	Fast Start	Percent Fast Start Increase
2021	Sep	$27.22	$29.08	$28.55	$30.41	6.5%
	Oct	$35.64	$39.92	$37.12	$41.40	11.5%
	Nov	$50.56	$54.40	$52.43	$56.28	7.3%
	Dec	$25.62	$27.37	$27.05	$28.79	6.4%
2022	Jan	$68.25	$71.14	$69.68	$72.56	4.1%
	Feb	$31.14	$31.93	$32.76	$33.55	2.4%
	Mar	$23.91	$25.94	$25.70	$27.73	7.9%
	Apr	$45.07	$48.85	$47.49	$51.27	7.9%
	May	$38.09	$41.85	$39.84	$43.60	9.4%
	Jun	$47.26	$52.57	$49.17	$54.48	10.8%
	Jul	$47.40	$54.51	$48.92	$56.04	14.5%
	Aug	$57.43	$64.13	$59.17	$65.87	11.3%
	Sep	$46.17	$48.84	$48.07	$50.73	5.5%
Total		$45.30	$49.26	$47.08	$51.04	8.4%

Figure 10-18 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-18 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the predominant component of the total clearing price.

108 The performance component of the regulation market clearing price is unaffected by fast start pricing.

Figure 10-18 Regulation market clearing price components (Dollars per MW): January through September, 2022

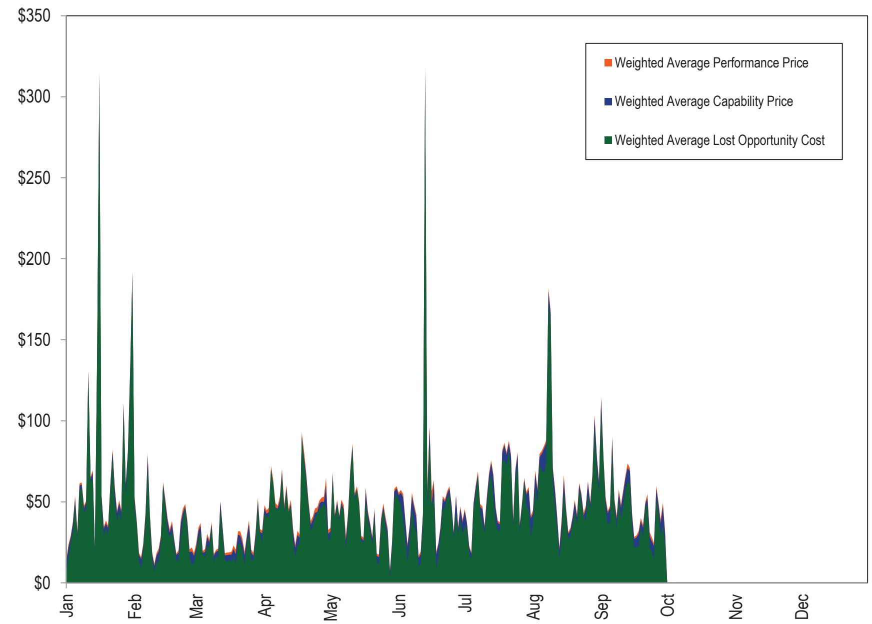


Table 10-56 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-18 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-56 Regulation market monthly component of price (Dollars per MW): January through September, 2022

Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
Jan	$71.14	$1.43	$72.56
Feb	$31.93	$1.62	$33.55
Mar	$25.94	$1.79	$27.73
Apr	$48.85	$2.42	$51.27
May	$41.85	$1.75	$43.60
Jun	$52.57	$1.92	$54.48
Jul	$54.51	$1.52	$56.04
Aug	$64.13	$1.74	$65.87
Sep	$48.84	$1.89	$50.73
Average	$49.26	$1.78	$51.04

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-57. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first nine months of 2022 was $211.8 million, compared to $87.9 million in the first nine months of 2021.

Table 10-57 Total regulation charges: January 2021 through September 2022

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2021	Jan	400,937.0	$6,038,564	$12.12	$15.06	80.5%
2021	Feb	364,533.3	$9,401,619	$20.60	$25.79	79.9%
2021	Mar	386,898.9	$8,793,373	$19.20	$22.73	84.5%
2021	Apr	373,462.9	$7,951,303	$17.34	$21.29	81.5%
2021	May	386,138.5	$8,051,297	$16.62	$20.85	79.7%
2021	Jun	390,494.1	$9,654,112	$19.22	$24.72	77.8%
2021	Jul	403,379.4	$9,696,300	$20.02	$24.04	83.3%
2021	Aug	404,161.2	$15,414,276	$33.13	$38.14	86.9%
2021	Sep	355,337.7	$12,923,840	$30.41	$36.37	83.6%
2021	Oct	373,226.9	$18,334,407	$41.40	$49.12	84.3%
2021	Nov	356,980.3	$24,453,797	$56.28	$68.50	82.2%
2021	Dec	389,951.2	$13,662,814	$28.79	$35.04	82.2%
	Yearly	4,585,501.3	$144,375,702	$26.00	$31.49	82.6%
2022	Jan	384,969.5	$34,046,042	$72.56	$88.44	82.1%
2022	Feb	349,755.8	$14,317,381	$33.53	$40.94	81.9%
2022	Mar	367,002.2	$13,057,959	$27.73	$35.58	77.9%
2022	Apr	355,900.6	$23,257,413	$51.27	$65.35	78.5%
2022	May	360,870.6	$19,641,413	$43.60	$54.43	80.1%
2022	Jun	384,946.7	$25,593,008	$54.48	$66.48	82.0%
2022	Jul	396,606.5	$28,295,746	$56.04	$71.34	78.5%
2022	Aug	391,060.2	$32,350,728	$65.87	$82.73	79.6%
2022	Sep	346,887.7	$21,260,643	$50.73	$61.29	82.8%
	Yearly	3,337,999.7	$211,820,333	$51.04	$63.46	80.4%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-58. Total scheduled regulation is based on settled performance adjusted MW. In the first nine months of 2022, the average total cost of regulation was $63.46 per MW, 150.1 percent higher than $25.37 in the first nine months of 2021. In the first nine months of 2022, the monthly average capability component cost of regulation was $50.64, 150.8 percent higher than $20.19 in the first nine months of 2021. In the first nine months of 2022, the monthly average performance component cost of regulation was $4.25, 66.0 percent higher than $2.56 in the first nine months of 2021. The increase of the average total cost in the first nine months of 2022 versus the first nine months of 2021, was primarily a result of higher LOC values due to higher prices in the energy market.

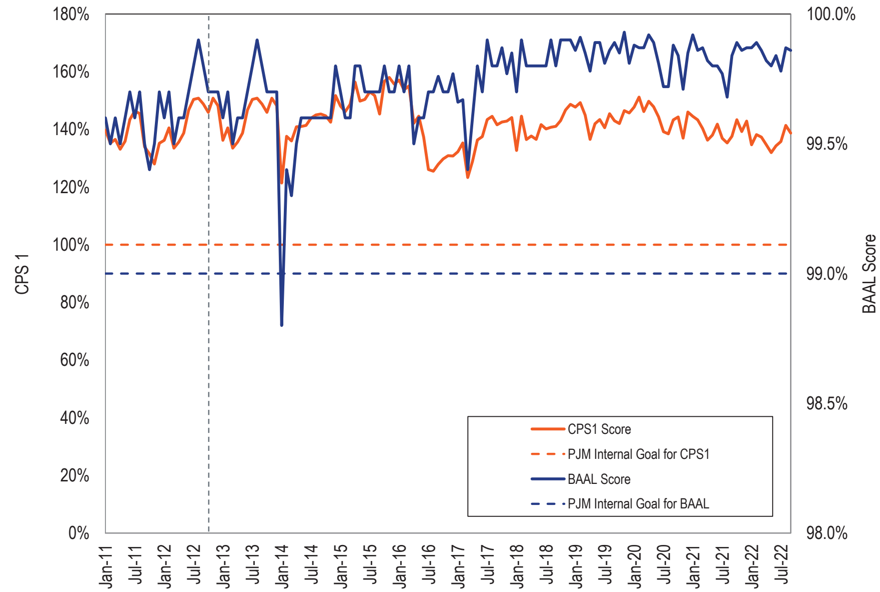
Table 10-58 Components of regulation cost: January 2021 through September 2022

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2021	Jan	400,937.0	$11.71	$1.67	$1.68	$15.06
	Feb	364,533.3	$19.90	$2.52	$3.37	$25.79
	Mar	386,898.9	$18.70	$1.86	$2.16	$22.73
	Apr	373,462.9	$16.63	$2.66	$2.00	$21.29
	May	386,138.5	$15.87	$2.40	$2.58	$20.85
	Jun	390,494.1	$18.45	$2.54	$3.73	$24.72
	Jul	403,379.4	$19.25	$2.68	$2.10	$24.04
	Aug	404,161.2	$32.19	$3.36	$2.58	$38.14
	Sep	355,337.7	$29.45	$3.41	$3.52	$36.37
	Oct	373,226.9	$40.60	$3.97	$4.55	$49.12
	Nov	356,980.3	$55.46	$4.80	$8.24	$68.50
	Dec	389,951.2	$27.87	$3.67	$3.50	$35.04
Yearly		4,585,501.3	$25.25	$2.94	$3.29	$31.49
2022	Jan	384,969.5	$72.12	$3.22	$13.10	$88.44
	Feb	349,755.8	$32.50	$3.77	$4.66	$40.94
	Mar	367,002.2	$26.45	$4.35	$4.78	$35.58
	Apr	355,900.6	$49.80	$5.67	$9.88	$65.35
	May	360,870.6	$43.22	$4.19	$7.02	$54.43
	Jun	384,946.7	$53.72	$4.38	$8.38	$66.48
	Jul	396,606.5	$56.22	$3.59	$11.53	$71.34
	Aug	391,060.2	$66.80	$4.32	$11.61	$82.73
	Sep	346,887.7	$51.27	$4.87	$5.16	$61.29
Yearly		3,337,999.7	$50.64	$4.25	$8.57	$63.46

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-19 for every month from January 2011 through September 2022 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[109] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-19 Monthly CPS1 and BAAL performance: January 2011 through September 2022



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 the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[110] Although the issue is being addressed in the stakeholder process, there are currently no firm fuel requirements for black start units.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff.[111] Currently, there is a small number of units in unique circumstances

109 See *2019 State of the Market Report for PJM*, Appendix F: Ancillary Services.

110 OATT Schedule 1 § 1.3BB.

111 *See* OATT Schedule 6A para. 18.

with bilateral agreements with their transmission operator (TO) to provide black start service that were entered into prior to joining PJM. These units are compensated directly from the TO.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.

On April 7, 2021, PJM issued an incremental RFP for additional black start service in the BGE and PEPCO Zones. The RFP is a two stage process. Level one submissions were due May 10, 2021. Level two submissions were due May 31, 2021. On November 1, 2021, PJM made awards for the April 7, 2021 incremental RFP. The planned in service date is April 1, 2023.[112]

Total black start charges are the sum of black start revenue requirement charges and black start uplift (operating reserve) charges.

Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor applicable when CRF rates are not used. The tariff specifies how to calculate each component of the revenue requirement formula.[113]

Fixed black start service costs are calculated using one of three methods chosen by the black start provider from the options defined in the OATT Schedule 6A: base formula rate; capital cost recovery rate; or incremental black start NERC-CIP cost recovery. The base formula rate is calculated by taking the net CONE multiplied by the black start unit's capacity multiplied by an x factor. The x factor is 0.01 for hydro units and 0.02 for CT units. The capital recovery rate is calculated by multiplying the capital investment by the CRF rate. The incremental NERC-CIP cost, for existing black start resources that need to add additional capital to meet NERC-CIP requirements, is calculated using the capital cost recovery rate. Black start uplift charges are paid to units committed in real time to provide black start service or for black start testing.[114] Total black start charges are allocated monthly to PJM customers based on their zone and nonzone peak transmission use and point to point transmission reservations.[115] It is not clear why it is reasonable to have different charges for black start service across zones as the service is to ensure that PJM as a whole can recover from a large scale outage.

In the first nine months of 2022, total black start charges were $51.70 million, an increase of $1.22 million (2.42 percent) from the first nine months of 2021. In the first nine months of 2022, total revenue requirement charges were $51.35 million, an increase of $1.07 million (2.14 percent) from the first nine months of 2021. In the first nine months of 2022, total uplift charges were $0.353 million, an increase of $0.149 million (73.35 percent) from the first nine months of 2021. Table 10-59 shows total charges for the first nine months of each year from 2010 through 2022.[116]

Table 10-59 Black start revenue requirement charges: January through September, 2010 through 2022

Jan-Sep	Revenue Requirement Charges	Uplift Charges	Total
2010	$8,527,000	$0	$8,527,000
2011	$9,996,898	$0	$9,996,898
2012	$13,288,491	$0	$13,288,491
2013	$15,728,447	$68,903,357	$84,631,804
2014	$18,395,320	$26,661,658	$45,056,978
2015	$39,718,855	$5,070,944	$44,789,799
2016	$51,565,656	$180,265	$51,745,921
2017	$52,422,434	$186,752	$52,609,186
2018	$48,938,203	$152,720	$49,090,923
2019	$48,231,346	$175,400	$48,406,746
2020	$49,052,199	$163,301	$49,215,499
2021	$50,278,321	$203,620	$50,481,941
2022	$51,352,216	$352,984	$51,705,199

Black start zonal charges in the first nine months of 2022 ranged from $0 in the OVEC and REC Zones to $14,722,406 in the AEP Zone. For each zone,

112 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
113 *See* OATT Schedule 6A para. 18.

114 There are no black start units currently using the ALR option.
115 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
116 Starting December 1, 2012, PJM defined a separate black start uplift category. ALR units accounted for the high uplift charges in 2013 – 2015. All ALR units had been replaced by April 2015.

Table 10-60 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[117] [118] Customers paid an average of $1.14 per MW-day for black start service in the first nine months of 2022.

Table 10-60 Black start zonal charges: January through September, 2021 and 2022[119]

	Jan- Sep 2021					Jan- Sep 2022				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$1,750,738	$11,402	$1,762,140	2,635	$2.45	$1,481,369	$2,207	$1,483,576	2,631	$2.07
AEP	$14,792,052	$38,346	$14,830,398	21,615	$2.51	$14,637,240	$85,166	$14,722,406	21,925	$2.46
APS	$3,712,845	$1,135	$3,713,980	8,638	$1.58	$4,864,033	$8,630	$4,872,663	8,865	$2.01
ATSI	$4,186,573	$0	$4,186,573	12,465	$1.23	$4,159,414	$0	$4,159,414	12,604	$1.21
BGE	$33,058	$95	$33,153	6,700	$0.02	$28,843	$210	$29,053	6,486	$0.02
COMED	$6,979,677	$21,647	$7,001,324	20,220	$1.27	$6,859,560	$55,482	$6,915,042	21,167	$1.20
DAY	$172,201	$13,958	$186,159	3,309	$0.21	$162,590	$24,487	$187,076	3,330	$0.21
DUKE	$284,041	$12,598	$296,638	4,975	$0.22	$263,414	$14,831	$278,245	5,306	$0.19
DUQ	$34,533	$0	$34,533	2,668	$0.05	$768,644	$1,575	$770,218	2,759	$1.02
DOM	$3,917,188	$40,029	$3,957,217	20,061	$0.72	$3,794,072	$67,128	$3,861,201	20,405	$0.69
DPL	$1,300,463	$14,191	$1,314,654	4,086	$1.18	$891,534	$20,906	$912,440	4,006	$0.83
EKPC	$246,074	$2,076	$248,150	2,720	$0.33	$202,246	$8,053	$210,299	2,851	$0.27
JCPLC	$525,736	$2,564	$528,300	5,903	$0.33	$421,468	$6,005	$427,473	6,169	$0.25
MEC	$357,434	$3,555	$360,989	2,976	$0.44	$368,800	$8,322	$377,121	3,072	$0.45
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$1,089,366	$2,199	$1,091,565	8,148	$0.49	$1,030,855	$4,489	$1,035,344	8,479	$0.45
PE	$3,264,496	$12,851	$3,277,347	2,911	$4.12	$3,248,504	$11,347	$3,259,850	2,900	$4.12
PEPCO	$242,012	$8,802	$250,814	5,887	$0.16	$234,502	$6,507	$241,009	5,829	$0.15
PPL	$3,646,821	$0	$3,646,821	7,260	$1.84	$3,659,238	$401	$3,659,639	7,517	$1.78
PSEG	$1,297,147	$9,300	$1,306,447	9,557	$0.50	$1,279,035	$8,379	$1,287,415	10,064	$0.47
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$2,445,867	$8,873	$2,454,740	7,798	$1.15	$2,996,856	$18,860	$3,015,716	9,702	$1.14
Total	$50,278,321	$203,620	$50,481,941	160,530	$1.15	$51,352,216	$352,984	$51,705,199	166,066	$1.14

Table 10-61 provides a revenue requirement estimate by zone for the 2022/2023, 2023/2024, and 2024/2025 Delivery Years.[120] Revenue requirement values are rounded up to the nearest $50,000, reflecting the uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly. The estimates do not reflect the impact of FERC decisions that could affect compensation for black start.

117 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 7.3 Black Start Service Charges, Rev. 95 (Oct. 1, 2022).
118 For each zone and import export/wheels the black start rates ($/MW day) are calculated by taking total charges by zone and divided by peak load then divided by days in the period.
119 Peak load for each zone is used to calculate the black start rate per MW day.
120 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

Table 10-61 Black start zonal revenue requirement estimate: 2022/2023 through 2024/2025 Delivery Years[121]

Zone	2022 / 2023 Revenue Requirement	2023 / 2024 Revenue Requirement	2024 / 2025 Revenue Requirement
ACEC	$2,100,000	$2,100,000	$2,100,000
AEP	$20,600,000	$20,700,000	$15,800,000
APS	$6,950,000	$6,950,000	$6,950,000
ATSI	$5,950,000	$5,950,000	$3,950,000
BGE	$50,000	$350,000	$3,500,000
COMED	$9,400,000	$9,650,000	$9,650,000
DAY	$250,000	$250,000	$250,000
DUKE	$350,000	$400,000	$400,000
DUQ	$1,100,000	$1,100,000	$1,100,000
DOM	$5,250,000	$5,350,000	$5,350,000
DPL	$1,250,000	$1,350,000	$1,350,000
EKPC	$300,000	$350,000	$350,000
JCPLC	$550,000	$650,000	$650,000
MEC	$500,000	$550,000	$550,000
OVEC	$0	$0	$0
PECO	$1,400,000	$1,550,000	$1,550,000
PE	$4,550,000	$4,650,000	$4,650,000
PEPCO	$250,000	$650,000	$5,550,000
PPL	$5,250,000	$5,300,000	$5,300,000
PSEG	$1,750,000	$1,800,000	$1,800,000
REC	$0	$0	$0
Total	$67,800,000	$69,650,000	$70,800,000

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units when new equipment is added to provide black start capability.[122] The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a formula (or a correctly defined standard financial model) that accounts for the weighted average cost of capital and its components, plus depreciation and taxes. The PJM CRF table was created in 2007 as part of the new RPM capacity market design and incorporated in Attachment DD to the PJM OATT. That CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules.[123] The CRF table in the tariff included assumptions about tax rates that were significantly too high after the changes to the tax code in 2017. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017.

The CRF table for existing black start units includes the column header, term of black start commitment, which is misleading and incorrect. The column is simply the cost recovery period. Accelerated recovery reduces risk to black start units and should not be the basis for a shorter commitment. Full payment of all costs of black start investment on an accelerated basis should not be a reason for a shortened commitment period. Regardless of the recovery period, payment of the full costs of the black start investment should require commitment for the life of the unit.[124] In addition, there is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

The U.S. Internal Revenue Code changed significantly in December 2017. The PJM CRF table did not change to reflect these changes. As a result, CRF values have overcompensated black start units since the changes to the tax code. The new tax law allow for a more accelerated depreciation and reduced the corporate tax rate to 21 percent.

Updated CRF rates, incorporating the tax code changes and applicable to all black start units, should be implemented immediately. The updated CRF rates should apply to all black start units because the actual tax payments for all black start units were reduced by the tax law changes. Without this change, black start units are receiving and will continue to receive an unexpected and inappropriate windfall.

On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[125] PJM proposed to bifurcate the CRF calculation, applying an updated CRF calculation that incorporates the new federal tax law to new black start units while leaving the outdated and incorrect CRF in place for

121 The 2024/2025 estimated revenue requirement is based on the CONE values for the 2023/2024 RPM Base Residual Auction because the 2024/2025 RPM Base Residual Auction has not been run.
122 *See* OATT Schedule 6A para. 18.
123 *Id.*
124 PJM's recent filing to revise Schedule 6A includes a required commitment to provide black start service for the life of the unit. See FERC Docket No. ER21-1635.
125 *See* Docket No. ER21-1635-000.

existing black start units. Rather than fix the inaccurate CRF values used for existing black units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed comments on April 28, 2021.[126] The MMU objected to the continued use of the outdated CRF for existing units. The MMU also introduced a CRF formula for calculating the CRF for new black start units and requested that the CRF formula be included in the tariff.[127] [128] On August 10, 2021, FERC issued an order ("August 10th Order") that accepted PJM's tariff revisions that apply to new black start units (selected for service after June 6, 2021) and directed PJM to include the CRF formula proposed by the MMU.[129] The August 10th Order also established a show cause proceeding in a new docket to "determine whether the existing rates for generating units providing Black Start Service (Black Start Units), which are based on a federal corporate income tax that pre-dates the Tax Cuts and Jobs Act of 2017 (TCJA), remains just and reasonable."[130] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[131] [132] The request for rehearing was denied.[133] PJM's compliance filing to address the August 10 Order was accepted by letter order, subject to edits proposed by the MMU, on December 16, 2021.[134]

PJM's response to the show cause directive in the August 10th Order continued to support the use of the outdated CRF despite the Commission's statement that the CRF values "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[135] [136] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in $126 million of over recovery of black start capital investments.[137] Table 10-62 shows the over recovery of capital payments by resources awarded black start service prior to Jun 6, 2021 as result of PJM's continued application of the old CRF rate.

126 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021), which can be accessed at <http://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1635_20210428.pdf>.
127 Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
128 Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
129 176 FERC ¶ 61,080 at 42 and 44 (2021).
130 176 FERC ¶ 61,080 at 2 (2021).
131 Id. at 50.
132 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
133 177 FERC ¶ 62,017 (2021).
134 177 FERC ¶ 61,202 (2021).
135 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
136 August 10th Oder at 47.
137 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).

Table 10-62 CRF over recovery if CRF not corrected for changes in tax laws

	Excess Payback ($ million)	Percent
Selected for Service Prior to January 1, 2017	$36.05	28.6%
Selected for Service After January 1, 2019 and Before June 6, 2021	$89.93	71.4%
Total	$126.00	100.0%

The MMU also proposed an update to the CRF that reflects the return of capital already received by existing black start units and eliminates the over recovery that occurs under the PJM proposal. The updated CRF would be set at the level that covers the tax liabilities going forward, pays a return at the required rates on the remaining capital investment, pays back the full investment and results in the required return on and of capital over the CRF term. A description of the MMU's proposal and a formula for calculating the updated CRF are included in the MMU Comments.[138]

NERC – CIP

No black start units have requested new or additional black start NERC – CIP Capital Costs.[139]

Reactive Power Service and Capability

Suppliers of reactive power are compensated separately for reactive power service and reactive capability.

Compensation for reactive power service is based on real-time lost opportunity costs.[140] Reactive service is generally provided by units reducing real power output in order to increase reactive power output. These units are paid uplift based on lost opportunity costs.[141]

Compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT. Resources may

138 Id. (Attachment B, Section H at 18).
139 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."
140 See OA Schedule 1 § 3.2.3B.
141 Id.

obtain FERC approval to recover a reactive revenue requirement, the reactive capability rate, from PJM customers.[142]

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[143] PJM in its role as the independent RTO and transmission provider determines the reactive capability it needs from all sources in order to reliably operate the grid. PJM, as part of its Interconnection Agreements with resources, requires that all resources over 20 MW be able to operate at a power factor of 0.90 lagging to 0.95 leading throughout their entire operating range. Reactive power helps maintain appropriate voltages on the transmission system and must be sourced locally.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements. Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers based on their zonal and to any nonzonal (outside of PJM) peak transmission use and daily average point to point transmission reservations.[144] [145]

In 2016, FERC began to reexamine its policies on reactive compensation.[146] On November 18, 2021, the FERC issued a notice of inquiry (NOI) concerning reactive power capability compensation.[147] The Market Monitor responded to the NOI.[148]

Issues with Reactive Capability Market Design

The NOI inquires about reactive power capability compensation under the *AEP* Method, alternative methods of compensation, and resources interconnected at the distribution level. The fundamental question is whether market design in the organized wholesale markets requires separate, guaranteed cost of service compensation for reactive capability. The answer is no. In the PJM market design, investment in resources is fully recoverable through markets. The PJM markets are a complete set of markets that are self sustaining. Unlike some ISO/RTO designs, the PJM market relies on markets rather than cost of service regulation or bilateral contracts to pay for capacity. Generators will invest in markets when the expected revenues provide for the payment of all costs and a return on and of capital. That is the way competitive markets work. It would be more equitable, more consistent with the PJM competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mixing of regulatory paradigms.

Even if the PJM design worked in the way asserted by supporters of cost of service payments for reactive, the best possible outcome would be the same as the market outcome. There would be an opportunity to recover all costs. A simple application of Occam's razor implies that the market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why a nonmarket approach is required in PJM or why it is preferable to a market approach.

The current process is an inefficient waste of time because it relies on an atavistic regulatory paradigm that is not relevant in the PJM market framework. The *AEP* Method was created, before the creation of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs. At the time, AEP collected both generation and transmission costs under the same cost of service approach. There is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome cost of service rate proceedings. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue.

Applying cost of service rules is costly and burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box

142 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 95 (Oct. 1, 2022).
143 OATT Schedule 2.
144 OATT Schedule 2.
145 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 95 (Oct. 1, 2022).
146 See *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).
147 *Reactive Power Capability Compensation*, 177 FERC ¶ 61,118 (2021).
148 See Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (February 22, 2022); Reply Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (March 23, 2022); see also Comments of the Independent Market Monitor for PJM, Docket No. AD16-17-000 (July 29, 2016).

settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year for the same service.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The NOI presents an opportunity to address the reactive issue using a market based approach. The best approach would be to issue a rule eliminating cost of service rates for reactive capability and allowing for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve Net CONE value, currently $2,199 per MW-year.

As with all things in PJM markets, it is easy to focus on extreme complexity and lose sight of the big picture. The complexity includes power factors and power factor testing and convoluted and arbitrary allocation factors. The big picture here is that in PJM, the interrelated and self sustaining markets provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capacity costs should be paid directly in a non market, guaranteed, riskless revenue stream rather than in the market. The existence of the current option creates strong incentives for generators to attempt to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues.

The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

The PJM market design allows for the competitive investment in generation resources. The addition of separate rules allowing for the recovery of an arbitrarily defined portion of the same investment on a cost of service basis introduces a flaw into the competitive market design. The flaw is exacerbated when separate cost of service proceedings define the revenue requirement cost to supply reactive at values ranging from $13,044 to $964 per MW-year. (See Table 10-67)

The real issue is that the revenue requirement approach is inconsistent with both the theory and mechanics of PJM markets. The impact is to distort market outcomes.

The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-Year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[149] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[150] Unit specific reactive capability rates up to that $2,199 per MW-Year level are at least consistent with that parameter. Reactive capability rates either above or below that level distort capacity market outcomes. For example, a marginal resource with reactive revenue of $5,000 per MW-Year reflected in their net ACR offer would suppress the capacity market clearing price. Conversely, a marginal resource with a reactive revenue of $1,000 per MW-Year reflected in their net ACR offer would inflate the capacity market clearing price.

Interconnection Requirements

A generating facility is not eligible for reactive payments when it is not connected directly to the PJM system and therefore does not provide reactive capability to PJM under Schedule 2, and should not receive payments for a service that it does not and cannot provide. In a number of cases now pending, the Market Monitor has challenged the eligibility of resources filing under OATT Schedule 2 because they are interconnected to facilities that PJM does not monitor and does not rely on to provide reactive capability.[151]

Schedule 2 provides, "Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided *directly* by the Transmission Provider" [emphasis added]. PJM cannot rely on resources on an adjacent unmonitored system to directly provide reactive capability because the adjacent unmonitored system is under the control of another entity. PJM cannot attempt to directly dispatch a resource on an adjacent system without knowing the voltage conditions on that system. PJM would have to request assistance and cooperation of the entity responsible for the adjacent unmonitored system. Including a third party in the dispatch decision means PJM is not relying on the resources to directly provide Reactive Supply and Voltage Control Service.

The best place to understand PJM's role regarding the Lines is in the Designated Facilities List contained in the PJM manual on Transmission Operations referenced in the definition of Transmission Provider. PJM Manual 3 (Transmission Operations) sets forth the criteria for determining Monitored Transmission Facilities and the criteria for determining Reportable Transmission Facilities. PJM explains that "Monitored Transmission Facilities are monitored and controlled for limit violations using PJM's Security Analysis programs."[152] PJM explains that transmission facilities are "reportable if a change of its status can affect, or has the potential to affect, a transmission constraint on any Monitored Transmission Facility," or "if it impedes the free-flowing ties within the PJM RTO and/or adjacent areas."[153] The Monitored and Reportable Transmission Facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website.

PJM's criteria for defining Monitored Transmission Facilities and the criteria for defining Reportable Transmission Facilities determine which power lines constitute the PJM transmission system and which do not.

A resource interconnected on power lines that fail to meet the criteria defining Monitored Transmission Facilities *and* the criteria for defining Reportable Transmission Facilities are not interconnected to PJM's transmission facilities. PJM is not the Transmission Provider for such power lines. PJM does not directly rely on resources to provide Reactive Supply and Voltage Control Service, and they are therefore ineligible for compensation under Schedule 2.[154]

149 *See* OATT Attachment DD § 5.10(a)(v)(A).
150 OATT Attachment DD § 6.8(d).
151 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.

152 See PJM Manual 03:Transmission Operations, Rev. 64 (June 1, 2022).
153 See PJM, PJM Transmission Providers Facilities List On-Line Help (Last Updated: May 4, 2017), which can be accessed at: <trans-fac-help.ashx (pjm.com)>.
154 A facility that does not meet the criteria defining Reportable Transmission Facilities but does meet the criteria for defining Monitored Transmission Facilities is also not eligible under Schedule 2. If PJM does not operate the Lines, they are not PJM's transmission facilities. There is no evidence that PJM would rely on a resource to provide Reactive Supply and Voltage Control Service if the resource was located on a portion of the grid that PJM was monitoring but not operating. Coordination with the responsible operator would still be needed.

The issue will be decided in a hearing currently pending at the FERC.[155] The MMU has filed a motion for summary disposition, a prehearing brief and direct and answering testimony in that proceeding.[156] The hearing concluded on May 21, 2022. An initial decision is expected by July 15, 2022.

The issue of eligibility is significant because the number of facilities interconnecting at points that are not on the PJM system is expected to increase. Such facilities do not contribute reactive capability to PJM, and based on anticipated power factor levels and the way the *AEP* Method has been applied for calculating reactive rates under Schedule 2, such facilities would receive significantly larger payments per MW than the facilities that do provide reactive power capability useful to PJM.[157] These payments are for services not provided, but also would distort the PJM Capacity Market by paying a large share of the fixed costs of such facilities as reactive. This approach is a faulty and inefficient and noncompetitive market design.

Fleet Reactive Rates

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[158] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[159] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[160]

Table 10-63 identifies fleet rates currently effective in PJM.

155 See Whitetail Solar 1, LLC, et al., Docket No. ER20-714-003, et al.
156 Direct and Answering Testimony of Joseph E. Bowring, Docket No. ER20-714-003, et al. (November 15, 2021); Motion for Summary Disposition of the Independent Market Monitor for PJM, Docket No. ER20-714-003, et al. (April 5, 2022); Prehearing Brief of the Independent Market Monitor for PJM, Docket No. ER20-714-003, et al. (April 14, 2022).
157 See 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
158 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
159 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
160 *Id.*

Table 10-63 Fleet rates currently effective in PJM

Company	Fleet Rates	Number of Resources	FERC Dockets
Indiana Municipal Power Agency	$489,001.00	5	ER05-971-000
PBF Power Marketing (DCRC)	$588,597.00	3	ER14-357
Dominion Virginia Power	$27,500,000.00	66	ER06-554, ER17-512
Ingenco Wholesale Power, LLC	$888,913.24	11	ER20-1863

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems posed by fleet rates.[161] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[162] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[163]

The MMU also raised issues related to fleet rates in a settlement establishing a fleet rate without specifying the actual portion of the fleet rate attributable to each unit in the fleet.[164] The approach could prevent or inhibit an appropriate adjustment of the fleet requirement if a unit receiving an unspecified portion of such requirement is deactivated or transferred because third parties without access to cost information would bear the burden of proof in a complaint proceeding.[165] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[166]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates and that rates be appropriately reduced when units with reactive payments retire.

161 151 FERC ¶ 61,224 at P 29 (2015).
162 OATT Schedule 2.
163 *Id.*
164 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
165 *Id.*
166 162 FERC ¶ 61,029 (2018).

Reactive Costs

In the first nine months of 2022, total reactive charges were $289.9 million, an increase of $17.5 million (6.44 percent) from the first nine months of 2021. In the first nine months of 2022, total reactive capability charges were $288.6 million, an increase of $17.0 million (6.27 percent) from the first nine months of 2021. In the first nine months of 2022, total reactive service charges were $1.2 million, an increase of $0.49 million (65.98 percent) from the first nine months of 2021. In the first nine months of 2022, $1.2 million for reactive service charges were paid to 12 units for operation in 41 unit hours.

Table 10-64 shows reactive service charges for the first nine months of each year from 2010 through 2022.

Table 10-64 Reactive service charges and reactive capability charges: January through September, 2010 through 2022

Jan-Sep	Reactive Service Charges	Reactive Capability Charges	Total
2010	$8,813,427	$181,213,186	$190,026,613
2011	$20,783,028	$190,228,706	$211,011,735
2012	$49,432,233	$204,638,358	$254,070,591
2013	$184,710,913	$207,126,733	$391,837,646
2014	$27,516,739	$210,968,737	$238,485,476
2015	$9,989,075	$206,994,671	$216,983,746
2016	$838,204	$219,793,594	$220,631,798
2017	$14,047,245	$226,620,331	$240,667,577
2018	$12,428,626	$225,234,508	$237,663,134
2019	$465,836	$245,251,333	$245,717,170
2020	$412,336	$257,951,271	$258,363,607
2021	$738,644	$271,583,400	$272,322,045
2022	$1,225,976	$288,624,151	$289,850,127

Table 10-65 shows zonal reactive service charges for the first nine months in 2021 and 2022, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

Table 10-65 Reactive service charges and reactive capability charges by zone: January through September, 2021 and 2022

	Jan-Sep 2021			Jan-Sep 2022		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$3,218,354	$3,218,354	$0	$2,758,706	$2,758,706
AEP	$21,582	$36,387,800	$36,409,383	$0	$39,359,197	$39,359,197
APS	$0	$14,763,169	$14,763,169	$0	$16,745,023	$16,745,023
ATSI	$0	$18,985,976	$18,985,976	$0	$22,467,120	$22,467,120
BGE	$0	$4,978,284	$4,978,284	$267,035	$4,926,968	$5,194,003
COMED	$0	$30,577,228	$30,577,228	$0	$32,620,776	$32,620,776
DAY	$0	$2,111,251	$2,111,251	$0	$2,089,488	$2,089,488
DUKE	$0	$7,350,101	$7,350,101	$0	$7,036,013	$7,036,013
DOM	$0	$34,605,721	$34,605,721	$225,700	$38,255,967	$38,481,667
DPL	$1,517	$7,810,181	$7,811,698	$229,648	$7,458,256	$7,687,904
DUQ	$0	$427,864	$427,864	$0	$181,654	$181,654
EKPC	$1,231	$1,634,607	$1,635,838	$0	$1,617,757	$1,617,757
JCPLC	$0	$5,651,066	$5,651,066	$0	$5,592,814	$5,592,814
MEC	$8,696	$4,597,462	$4,606,159	$20,196	$4,521,660	$4,541,856
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$15,692,833	$15,692,833	$0	$14,913,242	$14,913,242
PE	$0	$12,940,806	$12,940,806	$0	$12,975,137	$12,975,137
PEPCO	$0	$7,499,913	$7,499,913	$483,396	$7,440,158	$7,923,554
PPL	$705,618	$27,453,430	$28,159,048	$0	$27,242,143	$27,242,143
PSEG	$0	$20,866,073	$20,866,073	$0	$22,718,329	$22,718,329
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$14,031,282	$14,031,282	$0	$17,703,745	$17,703,745
Total	$738,644	$271,583,400	$272,322,045	$1,225,976	$288,624,151	$289,850,127

Table 10-66 shows the units which received reactive service credits in the first nine months of 2022.

Table 10-66 Reactive service credits by plant (Total dollars): January through September, 2022

	Jan-Sep 2022	
Zone	Plant	Reactive Service Credits
BGE	BC BRANDON SHORES 1 F	$264,582
BGE	BC PERRYMAN 51 F	$2,453
DPL	DPL BAYVIEW 1 D	$2,668
DPL	DPL BAYVIEW 2 D	$2,927
DPL	DPL BAYVIEW 3 D	$1,920
DPL	DPL BAYVIEW 4 D	$962
DPL	DPL INDIAN RIVER 4 F	$221,172
METED	ME MOUNTAIN 2 CT	$9,637
METED	ME TOLNA 2 CT	$10,560
PEPCO	PEP CHALKPOINT 4 F	$483,396
DOM	VP ELIZABETH RIVER 1 CT	$206,962
DOM	VP ELIZABETH RIVER 3 CT	$18,738
Total		$1,225,976

Table 10-67 shows the settled reactive capability revenue requirements by technology effective on September 1, 2022.[167] These revenue requirements do not include revenue requirements that were filed but not yet final. The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

167 The total amount in the final row of Table 10-32 is the amount that would be paid if the total rate effective on September 1, 2022 were effective for an entire year. The total rates effective on any given day depend on requests made by resource owners in filings to FERC and FERC approval of those rates.

Table 10-67 Total settled reactive revenue requirements by unit type and fuel type: September 1, 2022

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Requirement per MW-year
CC	Gas	$122,983,072.65	49,423.2	155	$2,488.37
CT	Gas	$45,501,271.72	28,281.7	247	$1,608.86
CT	Oil	$4,693,276.29	3,291.2	114	$1,426.01
Diesel	Gas	$1,380,092.00	105.8	5	$13,044.35
Diesel	Oil	$1,028,787.05	168.2	36	$6,116.45
Diesel	Other - Gas	$915,140.45	115.4	11	$7,930.16
FC	Gas	$45,000.00	2.6	1	$17,307.69
Hydro	Water	$17,816,329.48	6,891.4	52	$2,585.30
Nuclear	Nuclear	$57,525,544.92	32,648.6	31	$1,761.96
Solar	Solar	$3,409,893.89	424.1	15	$8,040.31
Steam	Coal	$53,331,287.42	41,241.3	67	$1,293.15
Steam	Gas	$5,202,743.36	5,603.6	18	$928.46
Steam	Oil	$3,516,274.05	2,872.3	9	$1,224.20
Steam	Other - Solid	$340,000.00	34.0	2	$10,000.00
Steam	Wood	$207,803.43	153.0	3	$1,358.19
Wind	Wind	$18,664,267.97	4,791.6	37	$3,895.21
Total		$336,560,784.68	176,048.0	803	$1,911.76

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[168] Such equipment must include a governor or equivalent controls with the capability of operating at a maximum 5 percent droop and ± 0.036 Hz deadband (or the equivalent or better).

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[169]

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all

168 157 FERC ¶ 61,122 (2016).
169 See 164 FERC ¶ 61,224 (2018).

capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery.

Frequency Control Definition

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control (Regulation), and Tertiary Frequency Control (Primary Reserve).

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to changes in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins to respond within 10 to 15 seconds and can continue up to an hour. Regulation is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) was a combination of agreements among the entities in the VACAR Subregion including Dominion.[170] VACAR is a Subregion of the SERC Reliability Corporation (SERC) region. The agreement was terminated on October 1, 2022. The agreement required that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).[171] Dominion was the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA was not a public agreement. PJM was not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM was responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[172]

PJM procures synchronized reserves and primary reserves for the PJM region, including Dominion. The synchronized reserve and primary reserve requirements are equal to the largest single contingency and 150 percent of the largest contingency. The requirement is procured separately for the RTO and the MidAtlantic Dominion area (MAD) when the largest contingency is located outside of MAD. All units in PJM that meet the synchronized or primary reserve operating parameter requirements are eligible to meet the synchronized and primary requirements as long as PJM does not deselect them.

PJM procures Day-Ahead Scheduling Reserves (DASR) for the PJM region, including Dominion, as Secondary Reserves. The DASR requirement is calculated daily and is equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. All units in PJM that meet the DASR operating parameter requirements are eligible to meet the DASR requirement.[173] There is no

170 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.
171 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.
172 See PJM. "Manual 13: Emergency Operations," Rev. 84 (March 23, 2022).
173 DASR can be provided by units that do not clear the day-ahead energy market and can start within 30 minutes or by units that clear the day-ahead energy market and can ramp up within 30 minutes.

requirement that a specific amount of DASR be located in Dominion. Equation 1 shows the DASR requirement calculation.[174]

Equation 1: DASR Requirement Formula

$$\text{DASR Requirement} = (\text{RFC and EKPC Peak}) \times (\text{FOR} + \text{LFE}) + \text{DOM VACAR}$$

Issues

PJM implemented the reserve market changes effective October 1, 2022. These changes include the consolidation of synchronized reserves tier 1 and tier 2 and the reserve must offer requirement. With these changes, it would not have been possible for Dominion to hold reserves to meet its obligations under the VRSA without failing the must offer requirement in PJM. Under the reserve market changes, it would not have been possible for Dominion to meet both the VRSA and the PJM reserve rules.

Recommendations

The Market Monitor 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.[175]

174 During cold weather alerts and hot weather alerts, the DASR requirement is increased to procure additional reserves.
175 The VACAR RSA was terminated on October 1, 2022.

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution. CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[4] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the elected reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

PJM uses artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day ahead and real time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. These artificial constraints have been used to hide uplift costs by making them negative congestion charges. The use of artificial constraints is an inappropriate use of PJM discretion as the market operator, putting PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges.

5 The total congestion and marginal losses for 2022 were calculated as of October 10, 2022, and are subject to change, based on continued PJM billing updates.

Overview

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.

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.

Issues

Artificial Constraints, Closed Loop Interfaces and CT Pricing Logic

PJM has used, and in some cases, continues to use, artificial constraints in the day ahead and real time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. Some of these artificial constraints, such as CT pricing logic and closed loop interfaces, result in negative congestion charges that are an artifact of the artificial nature of the constraints that cause generation to be paid more than load pays for energy affected by the constraint. PJM also makes use of artificial constraints that function like closed loop interfaces but which result in positive congestion. These constraints are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint. These artificial constraints take the form of interfaces or enforced contingencies (modifications) on existing constraints. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day ahead and real time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. This is an inappropriate use of these tools as it puts PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. One of the side effects of these changes in parameters, besides causing modeling differences between the day ahead and real time market, is that the apparent location of the interface or parent constraint can move intra day relative to source and sink points.

While CT pricing logic was officially discontinued by PJM with the implementation of fast start pricing on September 1, 2021, PJM continues to use the same basic logic to force inflexible units to be on the margin in both real time and day ahead. PJM used CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to reduce the uplift associated with the dispatch of inflexible resources.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor.

In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[6] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of artificial constraints was and is a source of modeling differences between the day-ahead and real-time markets. When artificial constraints are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion.

Use of artificial constraints, closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

Like closed loop interfaces and CT pricing logic, some of the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays

6 The constrained side means the higher priced side with a positive CLMP created by the constraint.

this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing charges.

Locational Marginal Price (LMP)

Components

PJM uses a distributed load reference bus. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. Some congestion may be included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time load-weighted average LMP components for January through September, 2008 through 2022.[9]

The real-time load-weighted average LMP increased by $42.16 or 118.2 percent from $35.68 in the first nine months of 2021 to $77.84 in the first nine months of 2022. The real-time load-weighted average congestion component was $0.10 in the first nine months of 2022, compared to $0.03 in the first nine months of 2021. The real-time load-weighted, average loss component in the first nine months of 2022 was $0.06, compared to $0.02 in the first nine months of 2021. The real-time load-weighted average system energy component increased by $42.06 or 118.1 percent from $35.63 in the first nine months of 2021 to $77.68 in the first nine months of 2022. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero, although these components are not fully accurate.

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

9 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time load-weighted average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

Table 11-1 Real-time load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2022[10]

(Jan - Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$77.27	$77.15	$0.07	$0.05
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02
2014	$58.60	$58.61	($0.03)	$0.02
2015	$38.94	$38.89	$0.03	$0.02
2016	$29.32	$29.27	$0.04	$0.02
2017	$30.36	$30.32	$0.02	$0.01
2018	$39.43	$39.37	$0.04	$0.02
2019	$27.60	$27.56	$0.02	$0.02
2020	$21.22	$21.19	$0.02	$0.01
2021	$35.68	$35.63	$0.03	$0.02
2022	$77.84	$77.68	$0.10	$0.06

Table 11-2 shows the PJM day-ahead load-weighted average LMP components for January through September, 2008 through 2022. The day-ahead load-weighted average LMP increased by $41.46, or 116.7 percent, from $35.51 in the first nine months of 2021 to $76.97 in the first nine months of 2022. The day-ahead load-weighted average congestion component increased by $0.16 from $0.17 in the first nine months of 2021 to $0.32 in the first nine months of 2022. The day-ahead load-weighted average loss component was $0.18 in the first nine months of 2022, compared to $0.03 in the first nine months of 2021. The day-ahead load-weighted average energy component increased by $41.16, or 116.6 percent, from $35.31 in the first nine months of 2021 to $76.47 in the first nine months of 2022. Using a load-weighted reference bus, the day-ahead load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-2 Day-ahead load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2022

(Jan - Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$75.96	$76.30	($0.09)	($0.24)
2009	$39.35	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)
2014	$59.08	$58.84	$0.26	($0.01)
2015	$39.51	$39.25	$0.28	($0.02)
2016	$29.69	$29.54	$0.17	($0.01)
2017	$30.26	$30.24	$0.04	($0.02)
2018	$38.71	$38.60	$0.12	($0.01)
2019	$27.70	$27.63	$0.08	($0.01)
2020	$20.95	$20.88	$0.07	($0.01)
2021	$35.51	$35.31	$0.17	$0.03
2022	$76.97	$76.47	$0.32	$0.18

Table 11-3 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours.

Table 11-3 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2021 through September 2022

	2021		2022	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$25.96	$21.31	$69.75	$38.74
Feb	$45.23	$23.19	$47.17	$38.47
Mar	$26.57	$19.67	$43.43	$47.62
Apr	$26.93	$21.82	$63.91	$0.00
May	$30.74	$22.46	$84.99	$58.69
Jun	$35.33	$26.34	$105.87	$54.44
Jul	$42.25	$28.29	$98.97	$59.33
Aug	$53.08	$30.84	$125.07	$72.12
Sep	$52.26	$34.37	$80.41	$63.94
Oct	$59.05	$37.60		
Nov	$62.98	$65.82		
Dec	$39.32	$31.41		
Avg	$41.73	$27.52	$79.68	$60.58

10 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for the first nine months of 2021 and 2022. In the first nine months of 2022, DOM had the highest real-time congestion component of all control zones, $16.82, and ACEC had the lowest real-time congestion component, -$8.97.

Table 11-4 Zonal real-time load-weighted average LMP components (Dollars per MWh): January through September, 2021 and 2022

	2021 (Jan - Sep)				2022 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$32.26	$36.54	($4.68)	$0.39	$73.69	$81.12	($8.97)	$1.54
AEP	$35.70	$35.22	$0.54	($0.06)	$74.02	$76.47	($1.73)	($0.73)
APS	$35.21	$35.23	$0.14	($0.16)	$75.07	$76.43	($1.13)	($0.23)
ATSI	$34.76	$35.47	($0.88)	$0.18	$73.19	$76.94	($3.59)	($0.16)
BGE	$40.68	$35.97	$3.73	$0.98	$92.71	$78.80	$10.83	$3.09
COMED	$34.49	$35.88	($0.50)	($0.89)	$66.38	$77.47	($8.00)	($3.09)
DAY	$38.09	$35.66	$1.01	$1.42	$77.57	$77.46	($1.56)	$1.67
DOM	$39.68	$35.66	$3.64	$0.37	$96.46	$78.10	$16.82	$1.54
DPL	$37.57	$36.01	$0.83	$0.73	$80.70	$79.13	($0.88)	$2.46
DUKE	$37.03	$35.79	$1.20	$0.04	$76.28	$77.96	($0.94)	($0.74)
DUQ	$34.57	$35.64	($0.47)	($0.60)	$72.70	$77.92	($3.68)	($1.54)
EKPC	$36.12	$35.64	$0.64	($0.15)	$74.84	$77.14	($1.24)	($1.07)
JCPLC	$31.96	$36.57	($4.92)	$0.30	$75.30	$81.39	($7.28)	$1.19
MEC	$35.06	$35.49	($0.27)	($0.16)	$81.14	$77.39	$3.17	$0.58
OVEC	$32.71	$33.54	$0.02	($0.85)	$67.60	$71.45	($1.70)	($2.15)
PE	$32.72	$34.91	($1.85)	($0.34)	$71.43	$75.46	($3.74)	($0.30)
PECO	$31.29	$35.79	($4.36)	($0.13)	$70.72	$78.76	($8.44)	$0.39
PEPCO	$39.30	$36.00	$2.68	$0.63	$88.97	$78.87	$7.83	$2.27
PPL	$31.78	$35.18	($2.91)	($0.49)	$73.25	$76.37	($2.89)	($0.24)
PSEG	$33.53	$35.91	($2.62)	$0.24	$74.60	$79.29	($5.67)	$0.98
REC	$36.82	$36.62	($0.11)	$0.31	$78.57	$81.94	($4.33)	$0.96
PJM	$35.68	$35.63	$0.03	$0.02	$77.84	$77.68	$0.10	$0.06

The day-ahead components of LMP for each control zone are presented in Table 11-5 for the first nine months of 2021 and 2022. In the first nine months of 2022, DOM had the highest day-ahead congestion component of all control zones, $13.24, and ACEC had the lowest day-ahead congestion component, -$9.67.

Table 11-5 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): January through September, 2021 and 2022

	2021 (Jan - Sep)				2022 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$32.26	$36.07	($4.05)	$0.24	$70.80	$78.91	($9.67)	$1.56
AEP	$35.60	$35.01	$0.62	($0.03)	$75.19	$75.77	$0.19	($0.77)
APS	$35.21	$34.95	$0.39	($0.13)	$75.06	$74.64	$0.57	($0.14)
ATSI	$35.06	$34.96	($0.08)	$0.18	$74.49	$75.93	($1.27)	($0.16)
BGE	$40.42	$35.60	$3.84	$0.98	$90.51	$77.43	$9.83	$3.25
COMED	$34.10	$35.36	($0.57)	($0.70)	$68.04	$76.48	($5.89)	($2.55)
DAY	$38.21	$35.40	$1.19	$1.62	$78.54	$76.39	$0.43	$1.72
DOM	$38.92	$35.38	$3.21	$0.33	$91.94	$77.17	$13.24	$1.53
DPL	$36.53	$35.77	$0.01	$0.76	$76.52	$77.95	($4.22)	$2.79
DUKE	$37.21	$35.35	$1.60	$0.26	$78.14	$77.24	$1.51	($0.60)
DUQ	$34.86	$35.24	$0.21	($0.60)	$73.73	$76.58	($1.19)	($1.66)
EKPC	$36.06	$35.67	$0.68	($0.29)	$75.80	$76.26	$1.13	($1.58)
JCPLC	$32.15	$35.97	($3.98)	$0.16	$71.93	$79.18	($8.51)	$1.26
MEC	$34.94	$35.24	($0.01)	($0.28)	$80.60	$75.87	$3.83	$0.90
OVEC	$35.99	$37.89	($1.03)	($0.88)	$72.69	$73.65	$0.87	($1.83)
PE	$34.15	$35.11	($0.85)	($0.11)	$73.49	$75.39	($2.13)	$0.24
PECO	$31.18	$35.34	($3.89)	($0.27)	$68.60	$77.55	($9.45)	$0.50
PEPCO	$38.88	$35.70	$2.46	$0.72	$87.66	$77.89	$7.12	$2.65
PPL	$31.86	$34.81	($2.27)	($0.68)	$73.01	$75.35	($2.24)	($0.10)
PSEG	$32.67	$35.55	($3.03)	$0.15	$71.47	$77.13	($6.92)	$1.26
REC	$36.05	$36.34	($0.52)	$0.23	$75.98	$78.62	($3.97)	$1.33
PJM	$35.51	$35.31	$0.17	$0.03	$76.97	$76.47	$0.32	$0.18

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for the first nine months of 2021 and 2022.[11]

Table 11-6 Hub real-time average LMP components (Dollars per MWh): January through September, 2021 and 2022

	2021 (Jan - Sep)				2022 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.83	$29.12	($0.44)	($0.86)	$68.09	$72.43	($1.84)	($2.50)
AEP-DAY Hub	$29.77	$29.12	$0.71	($0.07)	$69.62	$72.43	($1.91)	($0.91)
ATSI Gen Hub	$27.60	$29.12	($1.11)	($0.42)	$67.66	$72.43	($3.24)	($1.53)
Chicago Gen Hub	$27.05	$29.12	($0.97)	($1.10)	$60.05	$72.43	($8.52)	($3.85)
Chicago Hub	$27.64	$29.12	($0.75)	($0.73)	$61.34	$72.43	($8.27)	($2.82)
Dominion Hub	$31.21	$29.12	$1.98	$0.10	$78.13	$72.43	$5.22	$0.49
Eastern Hub	$30.99	$29.12	$1.40	$0.47	$69.71	$72.43	($4.55)	$1.83
N Illinois Hub	$27.50	$29.12	($0.75)	($0.87)	$60.95	$72.43	($8.26)	($3.22)
New Jersey Hub	$26.28	$29.12	($2.96)	$0.12	$66.82	$72.43	($6.36)	$0.74
Ohio Hub	$30.02	$29.12	$0.90	($0.00)	$69.56	$72.43	($2.07)	($0.80)
West Interface Hub	$28.80	$29.12	$0.09	($0.41)	$71.21	$72.43	($0.19)	($1.03)
Western Hub	$28.85	$29.12	($0.04)	($0.23)	$73.14	$72.43	$0.58	$0.13

The day-ahead components of LMP for each hub are presented in Table 11-7 for the first nine months of 2021 and 2022.

Table 11-7 Hub day-ahead average LMP components (Dollars per MWh): January through September, 2021 and 2022

	2021 (Jan - Sep)				2022 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$32.42	$33.19	$0.16	($0.93)	$69.51	$71.96	$0.00	($2.45)
AEP-DAY Hub	$33.79	$33.19	$0.63	($0.03)	$71.01	$71.96	($0.10)	($0.85)
ATSI Gen Hub	$32.80	$33.19	($0.09)	($0.31)	$69.50	$71.96	($1.14)	($1.31)
Chicago Gen Hub	$31.28	$33.19	($0.86)	($1.06)	$62.17	$71.96	($6.48)	($3.31)
Chicago Hub	$31.92	$33.19	($0.68)	($0.60)	$63.39	$71.96	($6.25)	($2.32)
Dominion Hub	$34.98	$33.19	$1.83	($0.04)	$77.75	$71.96	$5.49	$0.30
Eastern Hub	$32.98	$33.19	($0.81)	$0.60	$68.33	$71.96	($5.81)	$2.18
N Illinois Hub	$31.68	$33.19	($0.71)	($0.80)	$62.90	$71.96	($6.29)	($2.77)
New Jersey Hub	$29.98	$33.19	($3.28)	$0.07	$65.78	$71.96	($7.16)	$0.98
Ohio Hub	$33.92	$33.19	$0.68	$0.05	$71.01	$71.96	($0.20)	($0.76)
West Interface Hub	$33.40	$33.19	$0.61	($0.41)	$72.23	$71.96	$1.20	($0.93)
Western Hub	$33.70	$33.19	$0.61	($0.10)	$74.56	$71.96	$1.83	$0.77

11 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[12] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[13] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction.
- **Balancing Implicit Load CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.

12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

13 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion accounting calculation equations are in Table 11-8.

Table 11-8 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs
MWh Category	**Definition**
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. Congestion costs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when

14 PJM Operating Agreement Schedule 1 §3.7.

negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs).

The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP calculation is designed to include no congestion or loss components, but it may include congestion. The load weighted average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative.

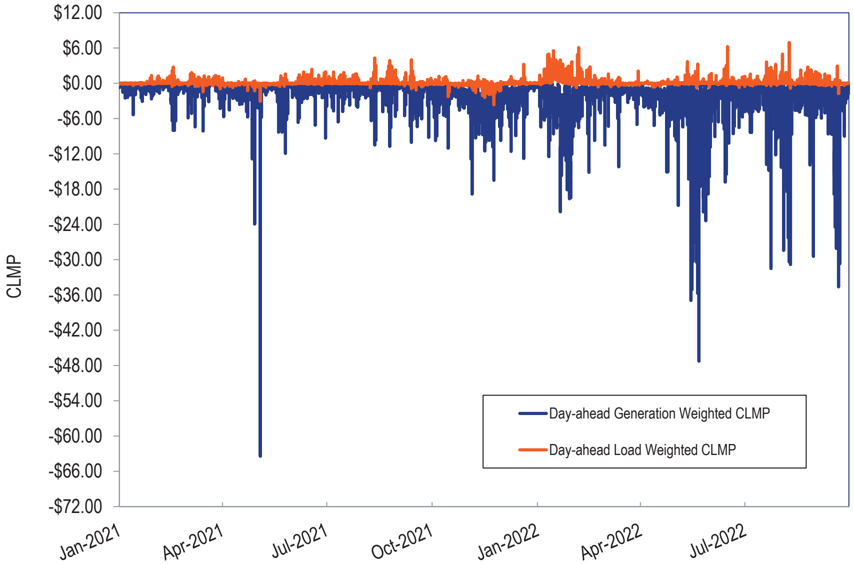
Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in January 2021 through September 2022, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-11 and Table 11-12). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

The day-ahead, generation weighted CLMPs were significantly negative for two hours on May 4, 2021, due to high shadow prices of two constraints caused by a transmission outage in the DOM Zone. The day-ahead generation weighted CLMPs were significantly negative for three hours on May 22, 2022 due to transmission constraint violations in HE 1400, HE 1700 and HE 1800. The day-ahead generation weighted CLMPs were significantly negative for

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

two hours on September 21, 2022, due to transmission constraint violations in HE 1600 and HE 1700 on the Brambleton - Evergreen Mills Line.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2021 through September 2022



Total Congestion

Total congestion costs in PJM in the first nine months of 2022 were $1,863.2 million, comprised of implicit withdrawal charges of $1,005.2 million, minus implicit injection credits of -$965.4 million, and plus explicit charges of -$107.4 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-9 shows total congestion for January through September, 2008 through 2022. Total congestion costs in Table 11-9 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16] [17]

Table 11-9 Total congestion costs (Dollars (Millions)): January through September, 2008 through 2022[18]

(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778	NA	$26,979	6.6%
2009	$544	(69.4%)	$19,927	2.7%
2010	$1,134	108.7%	$26,249	4.3%
2011	$875	(22.9%)	$28,836	3.0%
2012	$425	(51.4%)	$22,119	1.9%
2013	$510	19.9%	$25,153	2.0%
2014	$1,705	234.6%	$40,770	4.2%
2015	$1,143	(33.0%)	$33,710	3.4%
2016	$822	(28.1%)	$29,490	2.8%
2017	$455	(44.6%)	$29,510	1.5%
2018	$1,116	145.1%	$37,950	2.9%
2019	$419	(62.5%)	$31,850	1.3%
2020	$396	(5.5%)	$27,050	1.5%
2021	$615	55.1%	$37,550	1.6%
2022	$1,863	203.2%	$66,100	2.8%

CLMP charges and credits are not congestion. CLMP charges and credits reflect marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.
17 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.
18 In Table 11-9, 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.

Table 11-10 shows total congestion by day-ahead and balancing component for January through September, 2008 through 2022.

Table 11-10 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through September, 2008 through 2022

CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.2)	$0.0	$1,705.4
2015	$539.3	($783.2)	$24.6	$1,347.1	$11.4	$69.9	($145.6)	($204.1)	$0.0	$1,143.0
2016	$313.0	($529.0)	$35.7	$877.8	$1.9	$20.0	($37.3)	($55.5)	($0.0)	$822.2
2017	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4
2018	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2
2019	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.3)	$0.0	$419.1
2020	$139.3	($307.2)	$55.9	$502.5	($8.8)	$31.3	($66.3)	($106.3)	$0.0	$396.1
2021	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$0.0	$614.6
2022	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	($0.0)	$1,863.2

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market, that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-11 and Table 11-12 show the total CLMP charges and credits for each transaction type in the first nine months of 2022 and 2021. Table 11-11 shows that in the first nine months of 2022 DECs paid $25.4 million in CLMP charges in the day-ahead market, were paid $62.4 million in CLMP credits in the balancing energy market, resulting in a net payment of $37.1 million in total CLMP credits. In the first nine months of 2022, INCs paid $70.9 million in CLMP charges in the day-ahead market, were paid $127.4 million in CLMP credits in the balancing energy market resulting in a net payment of $56.5 million in total CLMP credits. In the first nine months of 2022, up to congestion (UTCs) paid $107.8 million in CLMP charges in the day-ahead market, were paid $220.3 million in CLMP credits in the balancing market resulting in a total payment of $112.5 million in total CLMP credits.

Table 11-11 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2022

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$25.4	$0.0	$0.0	$25.4	($62.4)	$0.0	$0.0	($62.4)	$0.0	($37.1)
Demand	$175.1	$0.0	$0.0	$175.1	$99.6	$0.0	$0.0	$99.6	$0.0	$274.7
Demand Response	$0.2	$0.0	$0.0	$0.2	($0.3)	$0.0	$0.0	($0.3)	$0.0	($0.2)
Explicit Congestion Only	$0.0	$0.0	$0.4	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.4
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.4)
Export	($38.9)	$0.0	($0.6)	($39.5)	($16.0)	$0.0	$4.2	($11.8)	$0.0	($51.3)
Generation	$0.0	($1,936.5)	$0.0	$1,936.5	$0.0	$101.6	$0.0	($101.6)	$0.0	$1,834.8
Import	$0.0	($7.1)	$0.0	$7.1	$0.0	($5.2)	($0.0)	$5.2	$0.0	$12.3
INC	$0.0	($70.9)	$0.0	$70.9	$0.0	$127.4	$0.0	($127.4)	$0.0	($56.5)
Internal Bilateral	$833.7	$836.3	$2.6	$0.0	($10.7)	($10.7)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$107.8	$107.8	$0.0	$0.0	($220.3)	($220.3)	$0.0	($112.5)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)	($1.1)	($0.6)	$0.0	($0.6)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.0	$0.0	($0.5)	$0.0	($0.5)
Total	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	$0.0	$1,863.2

Table 11-12 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2021

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$33.9	$0.0	$0.0	$33.9	($56.3)	$0.0	$0.0	($56.3)	$0.0	($22.4)
Demand	$68.9	$0.0	$0.0	$68.9	$27.7	$0.0	$0.0	$27.7	$0.0	$96.6
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$1.8	$1.8	$0.0	$0.0	($0.2)	($0.2)	$0.0	$1.6
Explicit Congestion and Loss Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($14.3)	$0.0	($0.5)	($14.8)	$2.1	$0.0	$0.0	$2.1	$0.0	($12.7)
Generation	$0.0	($635.6)	$0.0	$635.6	$0.0	$30.8	$0.0	($30.8)	$0.0	$604.8
Import	$0.0	($0.5)	$0.0	$0.5	$0.0	$3.4	$0.0	($3.4)	$0.0	($2.9)
INC	$0.0	($15.7)	$0.0	$15.7	$0.0	$33.5	$0.0	($33.5)	$0.0	($17.8)
Internal Bilateral	$236.0	$238.5	$2.4	($0.0)	($1.0)	($1.0)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$48.0	$48.0	$0.0	$0.0	($80.5)	($80.5)	$0.0	($32.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	$0.1	($0.7)	$0.0	($0.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.7	$0.0	$0.0	$0.7	$0.0	$0.7
Total	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$0.0	$614.6

Table 11-13 shows the change in total CLMP credits and charges by transaction type in the first nine months of 2021 and 2022. Total negative CLMP credits to generation increased by $1,230.1 million, and total CLMP charges to demand increased by $178.1 million. The total CLMP credits to up to congestion transactions (UTCs) increased by $80.1 million in the first nine months of 2022. Total day-ahead CLMP charges to UTCs increased by $59.8 million in the first nine months of 2022. Balancing CLMP credits to UTCs increased by $139.8 million in the first nine months of 2022.

Table 11-13 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2021 to 2022

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($8.5)	$0.0	$0.0	($8.5)	($6.1)	$0.0	$0.0	($6.1)	$0.0	($14.7)
Demand	$106.2	$0.0	$0.0	$106.2	$71.9	$0.0	$0.0	$71.9	$0.0	$178.1
Demand Response	$0.2	$0.0	$0.0	$0.2	($0.3)	$0.0	$0.0	($0.3)	$0.0	($0.2)
Explicit Congestion Only	$0.0	$0.0	($1.4)	($1.4)	$0.0	$0.0	$0.2	$0.2	$0.0	($1.2)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($24.6)	$0.0	($0.1)	($24.7)	($18.1)	$0.0	$4.1	($13.9)	$0.0	($38.6)
Generation	$0.0	($1,300.9)	$0.0	$1,300.9	$0.0	$70.8	$0.0	($70.8)	$0.0	$1,230.1
Import	$0.0	($6.6)	$0.0	$6.6	$0.0	($8.6)	($0.0)	$8.6	$0.0	$15.2
INC	$0.0	($55.2)	$0.0	$55.2	$0.0	$93.9	$0.0	($93.9)	$0.0	($38.7)
Internal Bilateral	$597.7	$597.9	$0.2	$0.0	($9.6)	($9.7)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$59.8	$59.8	$0.0	$0.0	($139.8)	($139.8)	$0.0	($80.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($1.2)	($1.1)	$0.1	$0.0	$0.1
Wheel Out	$0.0	$0.0	$0.0	$0.0	($1.2)	$0.0	$0.0	($1.2)	$0.0	($1.2)
Total	$670.9	($764.8)	$58.3	$1,494.0	$36.5	$145.3	($136.7)	($245.4)	$0.0	$1,248.6

Table 11-14 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in the first nine months of 2022. Total CLMP charges to generation decreased by $41.9 million, and total CLMP charges to demand increased by $0.1 million from the dispatch run to the pricing run. The total CLMP credits to DECs increased by $2.3 million, the total CLMP credits to INCs increased by $3.2 million and the total CLMP credits to UTCs increased by $1.7 million from the dispatch run to the pricing run.

Table 11-14 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): January through September, 2022

	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$23.4	($58.2)	($34.8)	$25.4	($62.4)	($37.1)	$2.0	($4.2)	($2.3)
Demand	$175.9	$98.7	$274.6	$175.1	$99.6	$274.7	($0.8)	$0.9	$0.1
Demand Response	$0.2	($0.4)	($0.2)	$0.2	($0.3)	($0.2)	($0.0)	$0.0	($0.0)
Explicit Congestion Only	$0.4	($0.0)	$0.4	$0.4	($0.0)	$0.4	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	($0.3)	($0.0)	($0.4)	($0.4)	($0.0)	($0.4)	($0.0)	($0.0)	($0.0)
Export	($40.1)	($12.4)	($52.5)	($39.5)	($11.8)	($51.3)	$0.6	$0.6	$1.2
Generation	$1,969.5	($92.7)	$1,876.8	$1,936.5	($101.6)	$1,834.8	($33.0)	($8.9)	($41.9)
Import	$7.4	$5.0	$12.4	$7.1	$5.2	$12.3	($0.3)	$0.2	($0.1)
INC	$71.6	($125.0)	($53.4)	$70.9	($127.4)	($56.5)	($0.8)	($2.4)	($3.2)
Internal Bilateral	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$107.6	($218.4)	($110.8)	$107.8	($220.3)	($112.5)	$0.3	($1.9)	($1.7)
Wheel In	$0.0	($0.5)	($0.5)	$0.0	($0.6)	($0.6)	$0.0	($0.1)	($0.1)
Wheel Out	$0.0	($0.5)	($0.5)	$0.0	($0.5)	($0.5)	$0.0	$0.0	$0.0
Total	$2,315.6	($404.5)	$1,911.1	$2,283.5	($420.3)	$1,863.2	($32.1)	($15.8)	($47.9)

UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through March 2022. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first nine months of 2022, 101.4 percent (-$220.3 million out of -$217.3 million) of negative balancing explicit CLMP charges was incurred by UTCs and -1.4 percent ($3.0 out of -$217.3 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-11). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[19] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[20]

19 For additional information about the FERC order, see the *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

20 172 FERC ¶ 61,046 (2020).

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTC: January 2014 through September 2022

Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.[21] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[22]

Table 11-16 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-15 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[23]

21 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

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

23 153 FERC ¶ 61,180 (2016).

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-15 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decremental bids and incremental offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of calculating the congestion from an individual constraint, the reference bus for each constraint calculation is the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

In order to define the load that is actually paying congestion, congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-16 shows day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, for the first nine months of 2022. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. DOM had the largest 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 zonal day-ahead congestion costs and -$83.2 million in zonal balancing congestion costs. The Brambleton - Evergreen Mills Line, the Greys Point - Harmony Village Line, the Nottingham Series Reactor, the Cumberland – Juniata Line and the Beaumeade Circuit Breaker contributed $173.1 million, or 51.4 percent of the DOM zonal congestion costs.[24]

As a result of the increased load in the Data Center Alley area of Northern Virginia, three of the top five constraints, in terms of total congestion revenue collected, were in the DOM zone. As a result, DOM load paid more congestion revenue due to constraints inside the DOM than due to constraints outside the DOM zone. In the first nine months of 2022, $180.0 million (53.4 percent) congestion costs in the DOM zone were from the constraints inside the DOM zone, compared to $35.9 million (40.4 percent) congestion costs in the first nine months of 2021.

Table 11-17 shows the congestion costs by zone for the first nine months of 2021.

Table 11-16 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through September, 2022

CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$8.4	($14.3)	$1.1	$23.8	$0.1	$2.5	($2.6)	($5.0)	$0.1	$18.7	$18.8
AEP	$128.9	($188.0)	$17.8	$334.6	$4.7	$31.3	($31.6)	($58.2)	$30.2	$246.3	$276.5
APS	$62.7	($86.3)	$6.6	$155.6	$0.7	$13.9	($13.8)	($27.1)	$7.2	$121.3	$128.5
ATSI	$62.1	($97.0)	$8.5	$167.6	$2.5	$15.5	($16.1)	($29.1)	$1.7	$136.8	$138.6
BGE	$33.6	($51.6)	$3.9	$89.1	$1.1	$8.9	($8.4)	($16.3)	$5.8	$66.9	$72.7
COMED	$83.4	($127.8)	$11.6	$222.8	$4.4	$22.6	($20.5)	($38.7)	$18.9	$165.2	$184.1
DAY	$14.1	($23.5)	$2.2	$39.8	$0.7	$4.2	($4.3)	($7.8)	$0.0	$31.9	$31.9
DOM	$295.9	($104.9)	$19.4	$420.2	($8.0)	$36.1	($39.1)	($83.2)	$180.0	$157.0	$337.0
DPL	$28.0	($34.5)	$2.5	$65.0	($1.6)	$4.2	($5.2)	($10.9)	$20.3	$33.8	$54.1
DUKE	$25.1	($35.2)	$3.5	$63.8	$1.2	$6.7	($6.9)	($12.4)	$3.4	$48.1	$51.5
DUQ	$9.9	($14.2)	$1.2	$25.3	$0.5	$3.1	($3.3)	($5.9)	$0.0	$19.4	$19.4
EKPC	$12.4	($18.1)	$1.7	$32.2	$0.4	$3.5	($3.4)	($6.5)	$0.0	$25.7	$25.7
EXT	$17.1	($18.0)	$1.6	$36.7	$1.2	$6.6	($6.8)	($12.2)	$3.3	$21.3	$24.6
JCPLC	$23.3	($39.6)	$2.8	$65.7	$0.2	$6.4	($6.8)	($13.0)	$0.7	$52.0	$52.7
MEC	$17.8	($25.3)	$1.8	$44.9	($0.4)	$4.1	($4.1)	($8.5)	$3.3	$33.1	$36.3
OVEC	$0.9	($1.3)	$0.8	$2.9	$0.0	$0.3	($0.3)	($0.5)	$0.7	$1.8	$2.4
PE	$19.9	($28.2)	$2.2	$50.3	$0.2	$4.2	($4.3)	($8.3)	$4.8	$37.2	$42.0
PECO	$36.9	($64.4)	$4.4	$105.7	$0.1	$9.6	($10.1)	($19.7)	$11.4	$74.6	$86.0
PEPCO	$31.4	($46.0)	$3.8	$81.2	$1.0	$8.1	($7.7)	($14.8)	$0.3	$66.1	$66.4
PPL	$40.5	($88.7)	$6.5	$135.7	$0.6	$9.9	($10.2)	($19.4)	$42.3	$74.0	$116.3
PSEG	$41.5	($69.2)	$5.1	$115.8	($0.1)	$10.7	($11.3)	($22.0)	$5.3	$88.4	$93.8
REC	$1.9	($2.2)	$0.8	$4.8	$0.0	$0.4	($0.4)	($0.8)	$1.0	$3.0	$4.0
Total	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	$340.7	$1,522.5	$1,863.2

24 For additional information about the top 20 constraints that affected each zone, see the *2022 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-17 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through September, 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$2.9	($3.6)	$0.5	$7.0	($0.2)	$0.7	($0.9)	($1.8)	$0.5	$4.8	$5.3
AEP	$43.0	($75.5)	$8.2	$126.7	($3.0)	$10.3	($11.8)	($25.0)	$20.5	$81.2	$101.7
APS	$20.4	($29.7)	$2.6	$52.7	($1.2)	$3.9	($4.5)	($9.6)	$3.1	$40.0	$43.1
ATSI	$18.2	($37.6)	$3.9	$59.7	($1.4)	$5.1	($5.9)	($12.5)	$0.3	$46.9	$47.2
BGE	$10.4	($16.2)	$1.6	$28.2	($0.6)	$2.4	($3.1)	($6.1)	$3.0	$19.1	$22.1
COMED	$26.6	($60.1)	$6.6	$93.3	($2.0)	$8.1	($8.9)	($19.0)	$12.8	$61.5	$74.3
DAY	$3.2	($10.1)	$1.0	$14.3	($0.4)	$1.4	($1.7)	($3.5)	$0.0	$10.8	$10.8
DOM	$74.1	($34.5)	$7.1	$115.8	($5.7)	$8.6	($12.7)	($27.0)	$35.9	$52.9	$88.8
DPL	$33.6	($3.1)	$2.5	$39.3	($1.7)	$1.2	($1.8)	($4.7)	$26.2	$8.4	$34.6
DUKE	$5.6	($16.4)	$1.6	$23.6	($0.6)	$2.2	($2.8)	($5.6)	$1.4	$16.6	$18.0
DUQ	$2.1	($6.1)	$0.4	$8.6	($0.3)	$1.0	($1.2)	($2.5)	$0.1	$6.0	$6.2
EKPC	$2.9	($7.4)	$0.7	$11.0	($0.4)	$1.1	($1.3)	($2.8)	$0.0	$8.1	$8.2
EXT	$7.2	($9.6)	$1.5	$18.3	($2.5)	$4.8	($4.0)	($11.3)	$0.7	$6.3	$7.0
JCPLC	$5.5	($9.9)	$1.0	$16.4	($0.4)	$1.5	($1.9)	($3.9)	$0.0	$12.5	$12.5
MEC	$8.3	($8.6)	$0.9	$17.8	($1.9)	$1.2	($1.9)	($5.1)	$4.3	$8.5	$12.7
OVEC	$0.2	($0.4)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.1	$0.4	$0.5
PE	$8.8	($9.4)	$1.2	$19.4	($0.5)	$2.2	($1.8)	($4.6)	$1.6	$13.2	$14.8
PECO	$16.2	($18.0)	$1.9	$36.1	($0.9)	$2.8	($3.4)	($7.1)	$5.2	$23.8	$29.0
PEPCO	$9.6	($13.8)	$1.5	$24.8	($0.5)	$2.3	($2.7)	($5.5)	$0.2	$19.2	$19.3
PPL	$11.3	($23.4)	$2.7	$37.4	($1.0)	$2.9	($3.5)	($7.4)	$8.9	$21.1	$30.0
PSEG	$12.7	($19.3)	$2.5	$34.4	($1.5)	$3.5	($4.4)	($9.5)	($0.2)	$25.2	$24.9
REC	$1.9	($0.6)	$1.5	$3.9	($0.1)	$0.1	($0.2)	($0.4)	$2.8	$0.8	$3.5
Total	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$127.3	$487.3	$614.6

In cases where PJM has used an artificial constraint that causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the artificial constraint is handled as a special case. In the first nine months of 2022, the total congestion costs associated with these special cases were $13.0 million or 0.7 percent of the total congestion costs. Table 11-16 and Table 11-17 include congestion allocations from these special case artificial constraints.

There are five categories of artificial constraint based specific allocation special cases: congestion associated with artificial constraints with no downstream load bus (no load bus); congestion associated with artificial constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic (CT price setting logic); and congestion associated with nontransmission artificial facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[25]

25 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-18 and Table 11-19 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic, and similar artificial constraints employed by PJM to force resources to be marginal, generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first nine months of 2022 or 2021.

Table 11-18 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): January through September, 2022

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$23.8	$23.8	$0.0	($0.0)	$0.0	($0.0)	$0.0	($5.0)	($5.0)	$18.8	($0.0)	(0.1%)
AEP	$0.0	($0.1)	$0.0	$0.8	$0.0	$333.9	$334.6	$0.0	($0.2)	$0.0	$0.0	$0.0	($58.0)	($58.2)	$276.5	$0.5	0.2%
APS	$0.0	($0.0)	$0.0	$0.0	$0.0	$155.6	$155.6	$0.0	($0.1)	$0.0	($0.0)	$0.0	($27.0)	($27.1)	$128.5	($0.1)	(0.1%)
ATSI	$0.0	($0.1)	$0.0	$0.2	$0.0	$167.5	$167.6	$0.0	($0.1)	$0.0	($0.0)	$0.0	($29.0)	($29.1)	$138.6	$0.0	0.0%
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$89.1	$89.1	$0.0	($0.1)	$0.0	($0.0)	$0.0	($16.3)	($16.3)	$72.7	($0.0)	(0.1%)
COMED	$0.2	($0.1)	$0.0	$2.2	$0.0	$220.5	$222.8	$0.0	($0.2)	$0.0	($0.0)	$0.0	($38.5)	($38.7)	$184.1	$2.1	1.2%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$39.8	$39.8	$0.0	($0.0)	$0.0	($0.0)	$0.0	($7.8)	($7.8)	$31.9	($0.0)	(0.1%)
DOM	$0.0	($0.1)	$0.0	$0.5	$0.0	$419.7	$420.2	$0.0	($0.2)	$0.0	($0.0)	$0.0	($83.0)	($83.2)	$337.0	$0.3	0.1%
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$65.0	$65.0	$0.0	($0.0)	$0.0	($0.0)	$0.0	($10.9)	($10.9)	$54.1	($0.0)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$63.9	$63.8	$0.0	($0.0)	$0.0	($0.0)	$0.0	($12.3)	($12.4)	$51.5	($0.1)	(0.1%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$25.3	$25.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($5.9)	($5.9)	$19.4	($0.0)	(0.2%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$32.2	$32.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($6.4)	($6.5)	$25.7	($0.0)	(0.1%)
EXT	$3.2	($0.0)	$0.0	$0.1	$0.0	$33.4	$36.7	$0.0	($0.1)	$0.0	($0.0)	$0.0	($12.1)	($12.2)	$24.6	$3.2	13.0%
JCPLC	$0.7	($0.0)	$0.0	$0.0	$0.0	$65.0	$65.7	$0.0	($0.0)	$0.0	($0.0)	$0.0	($12.9)	($13.0)	$52.7	$0.6	1.1%
MEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$44.8	$44.9	$0.0	($0.0)	$0.0	($0.0)	$0.0	($8.5)	($8.5)	$36.3	$0.0	0.0%
OVEC	$0.0	($0.0)	$0.0	$0.7	$0.0	$2.3	$2.9	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.5)	($0.5)	$2.4	$0.7	27.3%
PE	$0.0	($0.0)	$0.0	$0.1	$0.0	$50.2	$50.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($8.2)	($8.3)	$42.0	$0.0	0.1%
PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$105.7	$105.7	$0.0	($0.1)	$0.0	($0.0)	$0.0	($19.6)	($19.7)	$86.0	($0.1)	(0.1%)
PEPCO	$0.0	($0.0)	$0.0	$0.1	$0.0	$81.1	$81.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($14.8)	($14.8)	$66.4	$0.0	0.0%
PPL	$0.2	($0.0)	$0.0	$6.1	$0.0	$129.5	$135.7	$0.0	($0.1)	$0.0	($0.0)	$0.0	($19.3)	($19.4)	$116.3	$6.2	5.3%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$115.8	$115.8	$0.0	($0.1)	$0.0	($0.0)	$0.0	($22.0)	($22.0)	$93.8	($0.1)	(0.1%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.8	$4.8	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.8)	($0.8)	$4.0	($0.0)	(0.1%)
Total	$4.3	($0.8)	$0.0	$11.0	$0.0	$2,269.0	$2,283.5	$0.0	($1.4)	$0.0	($0.0)	$0.0	($418.8)	($420.3)	$1,863.2	$13.0	0.7%

Table 11-19 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): January through September, 2021

	CLMP Credits and Charges (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$7.0	$7.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($1.7)	($1.8)	$5.3	($0.1)	(1.1%)
AEP	$0.0	($0.0)	$0.0	$0.2	($0.0)	$126.5	$126.7	$0.0	($0.5)	$0.0	($0.0)	($0.3)	($24.2)	($25.0)	$101.7	($0.6)	(0.6%)
APS	$0.0	($0.0)	$0.0	$0.2	($0.0)	$52.5	$52.7	$0.0	($0.2)	$0.0	($0.0)	($0.1)	($9.3)	($9.6)	$43.1	($0.2)	(0.4%)
ATSI	$0.0	($0.0)	$0.0	$0.0	($0.0)	$59.7	$59.7	$0.0	($0.3)	$0.0	$0.0	($0.1)	($12.1)	($12.5)	$47.2	($0.4)	(0.9%)
BGE	$0.0	($0.0)	$0.0	$0.0	($0.0)	$28.2	$28.2	$0.0	($0.1)	$0.0	$0.0	($0.1)	($5.9)	($6.1)	$22.1	($0.2)	(0.9%)
COMED	$0.8	($0.0)	$0.0	$3.0	($0.0)	$89.6	$93.3	$0.0	($0.4)	$0.0	$0.0	($0.2)	($18.4)	($19.0)	$74.3	$3.2	4.3%
DAY	$0.0	($0.0)	$0.0	$0.0	($0.0)	$14.3	$14.3	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.4)	($3.5)	$10.8	($0.1)	(1.0%)
DOM	$0.0	($0.0)	$0.0	$0.0	($0.0)	$115.7	$115.8	$0.0	($0.5)	$0.0	$0.0	($0.2)	($26.3)	($27.0)	$88.8	($0.7)	(0.8%)
DPL	$0.0	($0.0)	$0.0	$0.0	($0.0)	$39.3	$39.3	$0.0	($0.1)	$0.0	$0.0	($0.0)	($4.5)	($4.7)	$34.6	($0.1)	(0.4%)
DUKE	$0.0	($0.0)	$0.0	$0.4	($0.0)	$23.2	$23.6	($0.0)	($0.1)	$0.0	$0.0	($0.1)	($5.4)	($5.6)	$18.0	$0.3	1.5%
DUQ	$0.0	($0.0)	$0.0	$0.0	($0.0)	$8.7	$8.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.4)	($2.5)	$6.2	($0.1)	(1.3%)
EKPC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$11.0	$11.0	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.7)	($2.8)	$8.2	($0.1)	(1.2%)
EXT	$0.7	($0.0)	$0.0	$0.1	($0.0)	$17.6	$18.3	($0.0)	($2.7)	$0.0	$0.0	($0.0)	($8.5)	($11.3)	$7.0	($2.1)	(29.3%)
JCPLC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$16.4	$16.4	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.7)	($3.9)	$12.5	($0.1)	(1.1%)
MEC	$0.0	($0.0)	$0.0	$0.4	($0.0)	$17.4	$17.8	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($5.0)	($5.1)	$12.7	$0.3	2.2%
OVEC	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.6	$0.7	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.2)	($0.2)	$0.5	$0.1	14.6%
PE	$0.0	($0.0)	$0.0	$0.0	($0.0)	$19.4	$19.4	$0.0	($0.1)	$0.0	($0.6)	($0.0)	($3.9)	($4.6)	$14.8	($0.7)	(5.0%)
PECO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$36.2	$36.1	$0.0	($0.2)	$0.0	$0.0	($0.1)	($6.9)	($7.1)	$29.0	($0.3)	(0.9%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$24.8	$24.8	$0.0	($0.1)	$0.0	$0.0	($0.1)	($5.3)	($5.5)	$19.3	($0.2)	(0.8%)
PPL	$0.0	($0.0)	$0.0	$0.5	($0.0)	$36.9	$37.4	($0.0)	($0.2)	$0.0	$0.0	($0.1)	($7.1)	($7.4)	$30.0	$0.3	0.9%
PSEG	$0.0	($0.0)	$0.0	$0.0	($0.0)	$34.4	$34.4	$0.0	($0.2)	$0.0	$0.0	($0.1)	($9.2)	($9.5)	$24.9	($0.3)	(1.0%)
REC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$3.9	$3.9	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.4)	($0.4)	$3.5	($0.0)	(0.2%)
Total	$1.6	($0.2)	$0.0	$4.9	($0.0)	$783.2	$789.5	($0.0)	($6.0)	$0.0	($0.6)	($1.8)	($166.5)	($174.9)	$614.6	($2.1)	(0.3%)

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-20 compares the congestion costs between the dispatch run and the pricing run in the first nine months of 2022. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to decrease $32.1 million (or 1.4 percent), caused negative balancing congestion costs to increase $15.8 million (or 3.9 percent), and caused total congestion costs to decrease $47.9 million (or 2.5 percent) from the dispatch run to the pricing run in the first nine months of 2022. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-20 Total congestion by dispatch and pricing run (Dollars (Millions)) January through September, 2022

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$24.2	($4.8)	$19.4	$23.8	($5.0)	$18.8	($0.4)	($0.2)	($0.7)
AEP	$339.1	($56.1)	$283.0	$334.6	($58.2)	$276.5	($4.5)	($2.1)	($6.6)
APS	$157.3	($26.0)	$131.3	$155.6	($27.1)	$128.5	($1.7)	($1.1)	($2.8)
ATSI	$170.0	($27.9)	$142.0	$167.6	($29.1)	$138.6	($2.3)	($1.1)	($3.5)
BGE	$90.4	($15.7)	$74.7	$89.1	($16.3)	$72.7	($1.3)	($0.6)	($2.0)
COMED	$226.2	($37.4)	$188.9	$222.8	($38.7)	$184.1	($3.4)	($1.3)	($4.8)
DAY	$40.4	($7.6)	$32.8	$39.8	($7.8)	$31.9	($0.6)	($0.3)	($0.9)
DOM	$426.8	($81.0)	$345.8	$420.2	($83.2)	$337.0	($6.6)	($2.2)	($8.8)
DPL	$65.6	($10.1)	$55.5	$65.0	($10.9)	$54.1	($0.5)	($0.8)	($1.4)
DUKE	$64.8	($11.9)	$52.9	$63.8	($12.4)	$51.5	($1.0)	($0.4)	($1.4)
DUQ	$25.7	($5.7)	$20.0	$25.3	($5.9)	$19.4	($0.4)	($0.2)	($0.6)
EKPC	$32.7	($6.2)	$26.4	$32.2	($6.5)	$25.7	($0.5)	($0.2)	($0.7)
EXT	$37.1	($11.7)	$25.4	$36.7	($12.2)	$24.6	($0.4)	($0.5)	($0.8)
JCPLC	$66.8	($12.4)	$54.4	$65.7	($13.0)	$52.7	($1.1)	($0.6)	($1.7)
MEC	$45.4	($8.3)	$37.1	$44.9	($8.5)	$36.3	($0.6)	($0.2)	($0.8)
OVEC	$3.0	($0.5)	$2.4	$2.9	($0.5)	$2.4	($0.0)	($0.0)	($0.0)
PE	$50.8	($7.9)	$42.9	$50.3	($8.3)	$42.0	($0.5)	($0.4)	($0.9)
PECO	$107.2	($18.7)	$88.5	$105.7	($19.7)	$86.0	($1.5)	($0.9)	($2.4)
PEPCO	$82.4	($14.3)	$68.1	$81.2	($14.8)	$66.4	($1.2)	($0.5)	($1.8)
PPL	$137.2	($18.6)	$118.6	$135.7	($19.4)	$116.3	($1.5)	($0.8)	($2.3)
PSEG	$117.6	($21.0)	$96.6	$115.8	($22.0)	$93.8	($1.8)	($1.1)	($2.9)
REC	$4.9	($0.7)	$4.1	$4.8	($0.8)	$4.0	($0.1)	($0.0)	($0.1)
Total	$2,315.6	($404.5)	$1,911.1	$2,283.5	($420.3)	$1,863.2	($32.1)	($15.8)	($47.9)

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for January 2021 through September 2022. Total congestion costs were significantly higher in every month of the first nine months of 2022 than every month of the first nine months of 2021. Total day-ahead congestion costs in the first nine months of 2022 were highest in January and lowest in March mainly due to outages affecting the Greys Point – Harmony Village Line and cold weather in January.

Total negative balancing congestion costs in the first nine months of 2022 were greater in every month except February and March compared to the first nine months of 2021. The top five constraints that contributed to the total balancing congestion costs in the first nine months of 2022 were the Shadeland - Lafayette South Flowgate, the Nottingham Series Reactor, the Bedington - Black Oak Interface, the Greys Point - Harmony Village Line and the Greentown Flowgate. These five constraints accounted for 28.4 percent of the total balancing congestion costs in the first nine months of 2022.

Total negative balancing congestion costs were highest in January as a result of significant day-ahead and real-time pricing and modeling differences affecting the Greys Point - Harmony Village Line. January 16, 2022 contributed -$18.6 million (9.7 percent) of the -$191.2 million negative balancing congestion costs in the first nine months of 2022. The Bedington – Black Oak, AP South, East and AEP – DOM interfaces contributed 76.9 percent of that -$18.6 million in total balancing congestion as a result of modeling differences between real-time and day-ahead market, tripping of units and the load forecast error. The Bedington - Black Oak Interface and the Greys Point - Harmony Village Line were mainly binding in the first three months of 2022.

The Shadeland - Lafayette South Flowgate is the largest contributor to negative balancing congestion costs. The hourly average real-time shadow prices associated with the Shadeland - Lafayette South Flowgate were consistently higher than the hourly day-ahead shadow prices associated with the Shadeland - Lafayette South Flowgate throughout the first nine months of 2022. The Shadeland - Lafayette South Flowgate had constraint violations in

1,091 intervals in the real-time market from May to July while it was binding in the real-time market.

The Nottingham Series Reactor is the second to the largest contributor to negative balancing congestion costs due to hourly average real-time shadow prices that were consistently higher than the hourly day-ahead shadow prices throughout the first nine months of 2022 and real time line limits that were consistently lower than the day ahead modeled line limits.

The Greentown Flowgate is the fifth largest contributor to negative balancing congestion costs and it had constraint violations in 815 intervals in the real-time market in July and August. Another reason why the Greentown Flowgate had large negative balancing congestion costs is that it did not bind at all in the day-ahead market in the associated hours when it was binding in the real-time market.

Total congestion costs in the first nine months of 2022 were highest in May and lowest in March. The highest day-ahead congestion costs occurred, in order of cost, on May 21, 2022, May 22, 2022, and May 20, 2022, as a result of constraint violations that caused transmission penalty factors to set prices in the day-ahead market and hot weather alert events on May 20, 2022 and May 21, 2022.[26] In May, the top three constraints by total day-ahead congestion costs were the Brambleton - Evergreen Mills Line, the Idylwood – Clark Line and the Nottingham Series Reactor. The Brambleton - Evergreen Mills Line had a constraint violation that caused a transmission penalty factor to set price on May 22, 2022 and the Idylwood – Clark Line had constraint violations at four hours that caused a transmission penalty factor to set price on May 21, 2022 in the day-ahead market.

Table 11-21 Monthly congestion costs by market (Dollars (Millions)): January 2021 through September 2022

	Congestion Costs (Millions)							
	2021				2022			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$53.2	($24.1)	($0.0)	$29.1	$443.2	($123.8)	$0.0	$319.4
Feb	$90.3	($53.4)	$0.0	$36.9	$158.9	($42.6)	$0.0	$116.3
Mar	$81.0	($25.8)	$0.0	$55.2	$99.3	($24.7)	$0.0	$74.5
Apr	$81.8	($18.0)	($0.0)	$63.9	$145.9	($31.3)	($0.0)	$114.6
May	$104.4	($10.5)	$0.0	$94.0	$406.4	($52.2)	($0.0)	$354.2
Jun	$91.0	($15.9)	$0.0	$75.1	$202.0	($37.6)	$0.0	$164.4
Jul	$78.7	($3.4)	$0.0	$75.4	$223.6	($33.1)	$0.0	$190.5
Aug	$112.1	($16.6)	$0.0	$95.5	$355.6	($46.1)	($0.0)	$309.5
Sep	$97.0	($7.2)	$0.0	$89.8	$248.5	($28.7)	($0.0)	$219.8
Oct	$113.5	($14.4)	$0.0	$99.1				
Nov	$209.6	($34.3)	$0.0	$175.3				
Dec	$113.6	($7.3)	$0.0	$106.3				
Total	$1,226.2	($230.9)	$0.0	$995.3	$2,283.5	($420.3)	($0.0)	$1,863.2

26 PJM. System Operations Subcommittee. PJM Operations Summary May 2022 Operations (June 2, 2022) <https://www.pjm.com/-/media/committees-groups/subcommittees/sos/2022/20220602/20220602-item-04-operations-summary-may-2022.ashx>.

Figure 11-3 shows PJM monthly total congestion cost for the January through September, 2008 through 2022.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through September 2022

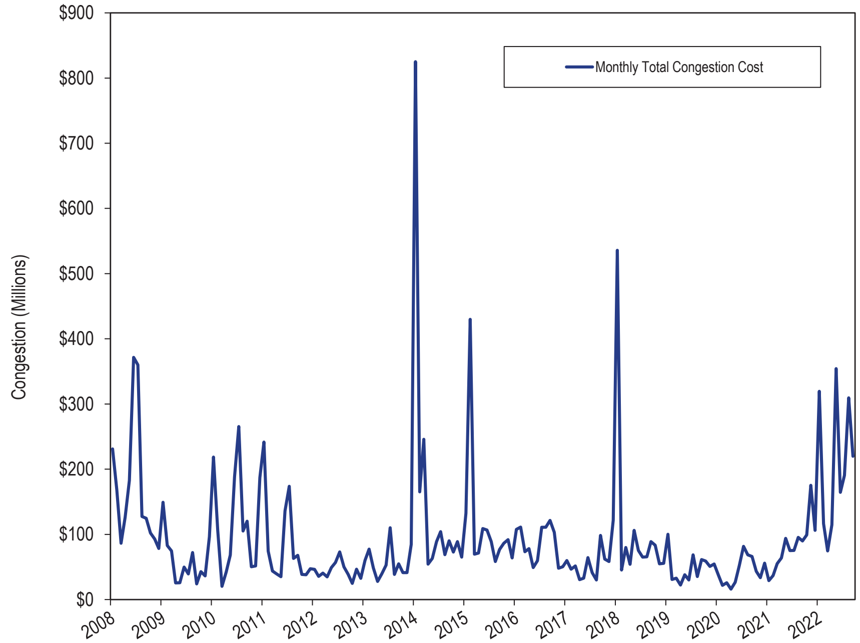


Table 11-22 shows monthly total CLMP credits and charges for each virtual transaction type in the first nine months of 2021 and 2022. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, CLMP credits in the first nine months of 2022 and 2021. In the first nine months of 2022, 54.6 percent of the total credits to virtuals went to UTCs, compared to 44.6 percent in the first nine months of 2021.

Table 11-22 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): January 2021 through September 2022

		CLMP Credits and Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2021	Jan	$3.0	($8.0)	($5.0)	$0.5	($0.1)	$0.4	$4.0	($10.0)	($6.0)	($10.5)
	Feb	$11.8	($24.7)	($12.9)	$0.6	($4.0)	($3.5)	$7.9	($20.9)	($13.0)	($29.4)
	Mar	$6.7	($7.7)	($1.0)	$4.0	($8.1)	($4.2)	$4.9	($6.0)	($1.1)	($6.2)
	Apr	($1.1)	$1.9	$0.8	$4.9	($8.4)	($3.5)	$3.1	($7.2)	($4.2)	($6.8)
	May	$0.5	($3.1)	($2.7)	$2.4	($2.6)	($0.2)	$5.5	($7.4)	($1.9)	($4.8)
	Jun	$4.2	($6.5)	($2.3)	$0.9	($2.9)	($2.0)	$6.8	($9.2)	($2.3)	($6.6)
	Jul	$2.6	($2.3)	$0.2	$0.2	($0.7)	($0.5)	$6.0	($4.6)	$1.4	$1.1
	Aug	$5.2	($5.0)	$0.2	$0.0	($2.8)	($2.8)	$4.6	($9.3)	($4.7)	($7.3)
	Sep	$1.0	($0.7)	$0.2	$2.1	($3.8)	($1.7)	$5.2	($5.8)	($0.6)	($2.1)
	Oct	($4.3)	$2.3	($2.0)	$4.2	($6.9)	($2.7)	$4.9	($6.1)	($1.2)	($5.9)
	Nov	($2.4)	($1.5)	($3.9)	$12.4	($16.9)	($4.5)	$7.2	($11.5)	($4.3)	($12.7)
	Dec	($2.6)	$0.5	($2.1)	$1.1	($3.0)	($1.9)	$2.6	($4.5)	($1.9)	($5.9)
	Total	$24.6	($55.0)	($30.4)	$33.4	($60.3)	($26.9)	$62.8	($102.6)	($39.8)	($97.2)
2022	Jan	$27.5	($45.7)	($18.3)	$4.4	($22.0)	($17.6)	$10.5	($38.3)	($27.8)	($63.7)
	Feb	$5.9	($20.9)	($15.1)	$5.4	($7.1)	($1.6)	$12.4	($17.6)	($5.1)	($21.8)
	Mar	($0.9)	($3.1)	($4.0)	$7.3	($9.5)	($2.2)	$9.7	($11.3)	($1.6)	($7.7)
	Apr	($3.0)	$3.1	$0.1	$12.5	($19.4)	($6.9)	$10.1	($22.4)	($12.3)	($19.1)
	May	($9.0)	$15.0	$6.0	$19.5	($28.8)	($9.2)	$14.9	($27.6)	($12.6)	($15.8)
	Jun	$1.8	($4.0)	($2.2)	$4.5	($8.3)	($3.8)	$10.5	($25.5)	($15.0)	($21.0)
	Jul	$2.0	($6.8)	($4.8)	$4.2	($6.5)	($2.3)	$12.1	($23.5)	($11.4)	($18.5)
	Aug	$1.8	$1.0	$2.7	$6.7	($17.7)	($10.9)	$16.3	($34.9)	($18.6)	($26.8)
	Sep	($0.6)	($1.0)	($1.6)	$6.2	($8.3)	($2.0)	$11.4	($19.3)	($7.9)	($11.6)
	Total	$25.4	($62.4)	($37.1)	$70.9	($127.4)	($56.5)	$107.8	($220.3)	($112.5)	($206.1)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In the first nine months of 2022, there were 50,120 day-ahead, congestion event hours compared to 41,946 day-ahead congestion event hours in the first nine months of 2021. Of the day-ahead congestion event hours in the first nine months of 2022, only 9,763 (19.5 percent) were also constrained in the real-time energy market (Table 11-25). In the first nine months of 2022, there were 20,728 real-time, congestion event hours compared to 15,401 real-time, congestion event hours in the first nine months of 2021. Of the real-time congestion event hours in the first nine months of 2022, 10,010 (48.3 percent) were also constrained in the day-ahead energy market (Table 11-26).

The top five constraints by congestion costs contributed $736.3 million, or 39.5 percent, of the total PJM congestion costs in the first nine months of 2022. The top five constraints were the Brambleton - Evergreen Mills Line, the Nottingham Series Reactor, the Cumberland - Juniata Line, the Beaumeade Circuit Breaker, and the Idylwood - Clark Line.

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours increased on all types of facilities except transformers in the first nine months of 2022. Congestion event hours on flowgates increased by 3,636 congestion event hours from 5,130 day-ahead, congestion event hours in the first nine months of 2021 to 8,766 day-ahead congestion event hours in the first nine months of 2022 (Table 11-25).

Real-time, congestion event hours increased on all types of facilities except transformers in the first nine months of 2022 (Table 11-26). Flowgates increased by 3,533 congestion event hours from 3,168 real-time, congestion event hours in the first nine months of 2021 to 6,701 real-time congestion event hours in the first nine months of 2022.

Day-ahead congestion costs increased on all types of facilities except transformers in the first nine months of 2022 compared to the first nine months of 2021 (Table 11-23).

Negative balancing congestion costs increased on all types of facilities except transformers in the first nine months of 2022 compared to the first nine months of 2021 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing the first nine months of 2022 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[27] [28]

27 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

28 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-23 Congestion summary (By facility type): January through September, 2022

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($56.4)	($277.5)	$20.0	$241.0	$4.2	$45.3	($67.7)	($108.8)	$132.2	8,766	6,701
Interface	$52.2	($117.1)	$5.3	$174.7	($12.1)	$50.6	($22.6)	($85.2)	$89.4	854	773
Line	$603.3	($713.6)	$62.8	$1,379.8	($9.3)	$65.1	($90.9)	($165.3)	$1,214.5	31,391	9,304
Transformer	$70.7	($75.2)	$6.2	$152.1	($1.1)	$7.9	($10.4)	($19.5)	$132.7	5,173	1,359
Other	$325.6	$5.3	$15.6	$336.0	$28.0	$43.9	($25.7)	($41.6)	$294.4	3,936	2,591
Unclassified	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	NA	NA
Total	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	$1,863.2	50,120	20,728

Table 11-24 Congestion summary (By facility type): January through September, 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($15.7)	($77.0)	$4.5	$65.8	$0.8	$17.2	($13.0)	($29.3)	$36.5	5,130	3,168
Interface	$0.1	($1.6)	$0.1	$1.9	($0.0)	$0.2	($0.2)	($0.4)	$1.5	37	86
Line	$224.2	($228.5)	$37.0	$489.6	($20.6)	$38.7	($53.9)	($113.1)	$376.4	28,675	8,556
Transformer	$79.9	($103.3)	$5.8	$188.9	($14.1)	$2.0	($7.8)	($23.8)	$165.1	5,662	1,795
Other	$36.0	($3.0)	$4.3	$43.3	$7.1	$8.8	($4.7)	($6.4)	$36.8	2,442	1,796
Unclassified	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.6	($1.1)	($1.8)	($1.8)	NA	NA
Total	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$614.6	41,946	15,401

Table 11-25 and Table 11-26 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-25.[29]

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-26.

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.

29 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-25 Congestion event hours (day-ahead against real-time): January through September, 2021 and 2022

Congestion Event Hours						
	2021 (Jan - Sep)			2022 (Jan - Sep)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Interface	37	7	**18.9%**	854	210	24.6%
Transformer	5,662	1,079	**19.1%**	5,173	802	15.5%
Flowgate	5,130	1,113	**21.7%**	8,766	2,696	30.8%
Line	28,675	3,846	**13.4%**	31,391	3,938	12.5%
Other	2,442	849	**34.8%**	3,936	2,117	53.8%
Total	41,946	6,894	**16.4%**	50,120	9,763	19.5%

Table 11-26 Congestion event hours (real-time against day-ahead): January through September, 2021 and 2022

Congestion Event Hours						
	2021 (Jan - Sep)			2022 (Jan - Sep)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Interface	86	7	8.1%	773	243	31.4%
Transformer	1,795	1,094	60.9%	1,359	811	59.7%
Flowgate	3,168	1,113	35.1%	6,701	2,704	40.4%
Line	8,556	3,881	45.4%	9,304	4,122	44.3%
Other	1,796	849	47.3%	2,591	2,130	82.2%
Total	15,401	6,944	45.1%	20,728	10,010	48.3%

Table 11-27 shows congestion costs by facility voltage class for the first nine months of 2022. Congestion costs in the first nine months of 2022 increased for all facility voltage classes except 161 kV and 69 kV facilities compared to the first nine months of 2021.

Table 11-27 Congestion summary (By facility voltage): January through September, 2022

	CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.7)	($7.4)	$0.6	$7.4	($0.2)	$1.2	($3.5)	($4.9)	$2.5	102	56
500	$103.2	($177.8)	$8.1	$289.2	($15.1)	$56.6	($26.8)	($98.5)	$190.7	2,457	1,254
345	($22.3)	($116.7)	$17.0	$111.5	($0.0)	$0.1	($22.9)	($23.0)	$88.5	4,391	1,393
230	$691.8	($629.3)	$48.7	$1,369.7	$41.5	$90.8	($95.6)	($144.9)	$1,224.8	18,550	8,127
220	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
161	($0.6)	($4.1)	$0.8	$4.3	$0.0	$0.4	($0.8)	($1.2)	$3.1	271	424
138	$25.7	($279.0)	$26.6	$331.4	$1.2	$46.2	($57.9)	($102.9)	$228.5	15,182	7,010
115	$187.8	$39.6	$6.6	$154.8	($17.3)	$17.7	($9.6)	($44.6)	$110.2	6,059	2,326
69	$10.4	($3.4)	$1.4	$15.2	($0.4)	($0.2)	($0.2)	($0.3)	$14.9	3,095	138
4.1	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	13	0
Unclassified	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	NA	NA
Total	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	$1,863.2	50,120	20,728

Table 11-28 Congestion summary (By facility voltage): January through September, 2021

	CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.3)	($1.2)	$0.2	$1.1	($0.5)	$0.3	($0.4)	($1.2)	($0.1)	18	5
500	$52.0	($63.1)	$3.4	$118.5	$4.4	$4.7	($4.8)	($5.2)	$113.3	2,482	1,913
345	($7.8)	($48.3)	$4.3	$44.8	($4.2)	$5.9	($6.4)	($16.5)	$28.3	2,994	1,341
230	$183.8	($144.6)	$23.1	$351.6	($19.3)	$21.2	($35.5)	($76.0)	$275.5	11,537	4,578
220	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	($0.0)	0	9
161	($2.6)	($8.2)	$0.3	$6.0	($0.4)	$0.4	($1.9)	($2.7)	$3.3	380	397
138	$32.9	($130.8)	$13.9	$177.7	($1.2)	$27.8	($25.3)	($54.3)	$123.4	14,625	5,056
115	$45.6	($13.3)	$3.2	$62.2	($5.5)	$3.0	($4.0)	($12.5)	$49.6	4,091	1,591
69	$20.8	($3.8)	$3.1	$27.7	$0.0	$3.5	($1.2)	($4.7)	$23.0	5,819	511
4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.6	($1.1)	($1.8)	($1.8)	0	0
Total	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$614.6	41,946	15,401

Constraint Frequency

Table 11-29 lists the constraints for the first nine months of 2021 and 2022 that were most frequently binding and Table 11-30 shows the constraints which experienced the largest change in congestion event hours from the first nine months of 2021 to 2022. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first nine months of 2022. In Table 11-30, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first nine months of 2021 to the first nine months of 2022.

Table 11-29 Top 25 constraints: January through September, 2021 and 2022

			(Jan - Sep)											
			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2021	2022	Change	2021	2022	Change	2021	2022	Change	2021	2022	Change
1	Nottingham	Other	1,005	3,182	2,177	522	2,126	1,604	15.3%	49%	33%	8%	32%	24%
2	Prest - Tibb	Flowgate	260	1,545	1,285	192	1,315	1,123	4%	24%	20%	3%	20%	17%
3	Lenox - North Meshoppen	Line	559	1,095	536	578	1,097	519	9%	17%	8%	9%	17%	8%
4	Shadeland - Lafayette South	Flowgate	0	861	861	0	877	877	0%	13%	13%	0%	13%	13%
5	Cumberland - Juniata	Line	448	1,160	712	188	495	307	7%	18%	11%	3%	8%	5%
6	Boonetown - South Reading	Line	241	1,009	768	191	632	441	4%	15%	12%	3%	10%	7%
7	Greys Point - Harmony Village	Line	75	763	688	44	548	504	1%	12%	11%	1%	8%	8%
8	Haumesser Road - Steward	Line	289	1,046	757	244	245	1	4%	16%	12%	4%	4%	0%
9	Chicago Ave - Praxair	Flowgate	24	729	705	12	503	491	0%	11%	11%	0%	8%	7%
10	Lackawanna	Transformer	0	609	609	0	516	516	0%	9%	9%	0%	8%	8%
11	Mountain	Transformer	262	1,115	853	0	0	0	4%	17%	13%	0%	0%	0%
12	Easton - Emuni	Line	554	1,065	511	5	0	(5)	8%	16%	8%	0%	0%	(0%)
13	Northwest Tap - Purdue	Flowgate	540	540	0	554	466	(88)	8%	8%	0%	8%	7%	(1%)
14	Brambleton - Evergreen Mills	Line	105	629	524	21	240	219	2%	10%	8%	0%	4%	3%
15	Gardners - Texas Eastern	Line	758	733	(25)	114	102	(12)	12%	11%	(0%)	2%	2%	(0%)
16	Maroa E - Goose Creek	Flowgate	160	500	340	68	232	164	2%	8%	5%	1%	4%	3%
17	Ramapo (ConEd) - S Mahwah (RECO)	Line	1,071	723	(348)	0	0	0	16%	11%	(5%)	0%	0%	0%
18	Conastone - Northwest	Line	215	492	277	61	188	127	3%	8%	4%	1%	3%	2%
19	Beaumeade	Other	0	377	377	0	303	303	0%	6%	6%	0%	5%	5%
20	Roxbury - Shade Gap	Line	63	621	558	4	30	26	1%	9%	9%	0%	0%	0%
21	Meridian - Twin Branch	Line	31	649	618	0	2	2	0%	10%	9%	0%	0%	0%
22	Cedar Grove Sub - William	Line	1,143	471	(672)	576	155	(421)	17%	7%	(10%)	9%	2%	(6%)
23	7713 - Crescent Ridge	Flowgate	219	610	391	0	0	0	3%	9%	6%	0%	0%	0%
24	Berwick - Koonsville	Line	1,351	608	(743)	1	0		21%	9%	(11%)	0%	0%	(0%)
25	Cayuga - Hilsdale N	Flowgate	0	346	346	0	250	250	0%	5%	5%	0%	4%	4%

Table 11-30 Top 25 constraints year to year change in occurrence: January through September, 2021 and 2022

			(Jan - Sep)												
			Congestion Event Hours						Percent of Annual Hours						
			Day-Ahead			Real-Time			Day-Ahead			Real-Time			
No.	Constraint	Type	2021	2022	Change	2021	2022	Change	2021	2022	Change	2021	2022	Change
1	Nottingham	Other	1,005	3,182	2,177	522	2,126	1,604	15%	49%	33%	8%	32%	24%
2	Prest - Tibb	Flowgate	260	1,545	1,285	192	1,315	1,123	4%	24%	20%	3%	20%	17%
3	Three Mile Island	Transformer	1,300	0	(1,300)	540	0	(540)	20%	0%	(20%)	8%	0%	(8%)
4	Shadeland - Lafayette South	Flowgate	0	861	861	0	877	877	0%	13%	13%	0%	13%	13%
5	Bagley - Raphael Road	Line	1,004	0	(1,004)	679	0	(679)	15%	0%	(15%)	10%	0%	(10%)
6	Brighton	Other	533	7	(526)	886	7	(879)	8%	0%	(8%)	14%	0%	(13%)
7	Boonetown - South Reading	Line	241	1,009	768	191	632	441	4%	15%	12%	3%	10%	7%
8	Chicago Ave - Praxair	Flowgate	24	729	705	12	503	491	0%	11%	11%	0%	8%	7%
9	Greys Point - Harmony Village	Line	75	763	688	44	548	504	1%	12%	11%	1%	8%	8%
10	Lackawanna	Transformer	0	609	609	0	516	516	0%	9%	9%	0%	8%	8%
11	Cedar Grove Sub - William	Line	1,143	471	(672)	576	155	(421)	17%	7%	(10%)	9%	2%	(6%)
12	Lenox - North Meshoppen	Line	559	1,095	536	578	1,097	519	9%	17%	8%	9%	17%	8%
13	Cumberland - Juniata	Line	448	1,160	712	188	495	307	7%	18%	11%	3%	8%	5%
14	Graceton - Safe Harbor	Line	1,180	380	(800)	415	204	(211)	18%	6%	(12%)	6%	3%	(3%)
15	Mountain	Transformer	262	1,115	853	0	0	0	4%	17%	13%	0%	0%	0%
16	Sandburg	Flowgate	450	0	(450)	392	6	(386)	7%	0%	(7%)	6%	0%	(6%)
17	Haumesser Road - Steward	Line	289	1,046	757	244	245	1	4%	16%	12%	4%	4%	0%
18	Monroe - Vineland	Line	824	145	(679)	77	4	(73)	13%	2%	(10%)	1%	0%	(1%)
19	Berwick - Koonsville	Line	1,351	608	(743)	1	0		21%	9%	(11%)	0%	0%	(0%)
20	Brambleton - Evergreen Mills	Line	105	629	524	21	240	219	2%	10%	8%	0%	4%	3%
21	Face Rock	Other	802	292	(510)	233	57	(176)	12%	4%	(8%)	4%	1%	(3%)
22	Beaumeade	Other	0	377	377	0	303	303	0%	6%	6%	0%	5%	5%
23	Rappahanock - White Stone	Line	522	0	(522)	149	0	(149)	8%	0%	(8%)	2%	0%	(2%)
24	North Coulterville	Flowgate	380	0	(380)	288	0	(288)	6%	0%	(6%)	4%	0%	(4%)
25	East Lima - Haviland	Line	871	483	(388)	370	93	(277)	13%	7%	(6%)	6%	1%	(4%)

Top Constraints

Table 11-31 and Table 11-32 show the top constraints contributing to congestion costs by facility for the first nine months of 2022 and 2021. 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 and 12.3 percent of the total PJM congestion costs in the first nine months of 2022. The constraints related to the Data Center Alley area of Northern Virginia comprised 26.6 percent of all PJM congestion costs in the first nine months of 2022.[30]

The Nottingham Series Reactor is the second to the largest contributor to congestion costs due to frequently binding since October 2021 due to a transformer outage. The day-ahead congestion event hours of Nottingham Series Reactor increased from 1,005 in the first nine months of 2021 to 3,182 in the first nine months of 2022 and the real-time congestion event hours of Nottingham Series Reactor increased from 522 in the first nine months of 2021 to 2,126 in the first nine months of 2022 (Table 11-29.)

30 This is the sum of the shares of total congestion costs for all DOM constraints in the top 25 except the Greys Point - Harmony Village Line.

Table 11-31 Top 25 constraints affecting congestion costs: January through September, 2022[31]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Brambleton - Evergreen Mills	Line	DOM	$123.6	($120.2)	$5.7	$249.5	$16.7	$11.9	($24.2)	($19.5)	$230.1	12.3%
2	Nottingham	Other	PECO	$233.3	$27.0	$11.6	$217.9	$19.6	$33.8	($10.9)	($25.1)	$192.8	10.3%
3	Cumberland - Juniata	Line	PPL	$22.3	($126.9)	$2.6	$151.7	$1.9	$3.6	($6.6)	($8.2)	$143.5	7.7%
4	Beaumeade	Other	DOM	$92.7	($16.3)	$3.6	$112.7	$9.4	$7.5	($15.5)	($13.6)	$99.1	5.3%
5	Idylwood - Clark	Line	DOM	$15.6	($55.3)	$1.4	$72.3	$2.7	$0.1	($4.0)	($1.5)	$70.9	3.8%
6	Conastone - Northwest	Line	BGE	$41.7	($11.4)	$2.9	$56.0	$1.2	$3.1	($1.7)	($3.6)	$52.5	2.8%
7	Dauphin - Juniata	Line	PPL	($19.6)	($66.8)	$2.2	$49.5	$0.0	$0.0	$0.0	$0.0	$49.5	2.7%
8	Bedington - Black Oak	Interface	500	$25.9	($44.7)	$1.9	$72.5	($0.8)	$15.1	($7.0)	($23.0)	$49.5	2.7%
9	Greys Point - Harmony Village	Line	DOM	$139.0	$79.5	$3.3	$62.8	($15.8)	$2.2	($3.5)	($21.5)	$41.3	2.2%
10	Coolspring - Milford	Line	DPL	$6.0	($33.2)	$0.6	$39.9	($5.5)	($3.6)	($1.2)	($3.1)	$36.8	2.0%
11	AP South	Interface	500	$24.1	($28.5)	$2.0	$54.6	($1.8)	$12.7	($5.1)	($19.6)	$35.0	1.9%
12	Prest - Tibb	Flowgate	MISO	($9.1)	($45.3)	$5.4	$41.6	$0.5	$3.4	($5.2)	($8.1)	$33.5	1.8%
13	Frackville - Siegfried	Line	PPL	$9.0	($22.5)	$0.9	$32.4	$0.0	$0.0	$0.0	$0.0	$32.4	1.7%
14	Ashburn - Cochran Mill	Line	DOM	$27.7	($8.2)	$0.8	$36.8	$5.1	$9.1	($1.2)	($5.2)	$31.5	1.7%
15	Bull Run - Clifton	Line	DOM	$20.7	($8.0)	$2.0	$30.7	$0.8	$0.1	($0.7)	($0.0)	$30.7	1.6%
16	Conastone	Transformer	500	$18.0	($11.7)	$0.0	$29.7	($0.5)	$2.4	($0.2)	($3.1)	$26.6	1.4%
17	Lauschtown	Transformer	500	$11.7	($13.2)	$0.9	$25.8	$0.0	$0.0	$0.0	$0.0	$25.8	1.4%
18	Boonetown - South Reading	Line	MEC	$1.1	($22.9)	$0.6	$24.6	($0.2)	$0.1	($0.5)	($0.8)	$23.8	1.3%
19	Lenox - North Meshoppen	Line	PE	$7.9	($29.9)	$2.9	$40.7	($0.3)	$12.7	($5.9)	($18.9)	$21.8	1.2%
20	Maroa E - Goose Creek	Flowgate	MISO	($8.6)	($28.9)	$0.3	$20.6	$0.2	($0.4)	($2.1)	($1.6)	$19.0	1.0%
21	Meridian - Twin Branch	Line	AEP	($2.3)	($13.4)	$6.9	$18.0	$0.1	($0.3)	($1.2)	($0.7)	$17.2	0.9%
22	Charlottesville - Proffit D.P.	Line	DOM	$7.3	($8.5)	$1.1	$16.9	$0.2	($0.2)	($0.2)	$0.2	$17.2	0.9%
23	Conastone - Peach Bottom	Line	500	$18.0	($1.5)	$1.5	$21.0	($0.3)	$1.9	($1.8)	($4.0)	$17.1	0.9%
24	Greenway - Shellhorn	Line	DOM	$11.3	($10.2)	$0.3	$21.7	$4.6	$7.6	($2.2)	($5.2)	$16.5	0.9%
25	Graceton - Safe Harbor	Line	BGE	$18.7	$1.1	$0.7	$18.4	$1.3	$3.1	($0.7)	($2.5)	$15.9	0.9%
	Top 25 Total			$835.9	($620.1)	$62.2	$1,518.2	$39.0	$125.8	($101.7)	($188.5)	$1,329.7	71.4%
	All Other Constraints			$159.5	($558.1)	$47.7	$765.3	($29.3)	$86.9	($115.5)	($231.8)	$533.5	28.6%
	Total			$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	$1,863.2	100.0%

31 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-32 Top 25 constraints affecting congestion costs: January through September, 2021[32]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Three Mile Island	Transformer	500	$28.7	($34.2)	$1.7	$64.6	$0.1	($2.3)	($1.2)	$1.3	$65.8	10.7%
2	Pleasant View - Ashburn	Line	DOM	$29.7	$1.9	$0.7	$28.5	$0.8	$0.4	($1.1)	($0.7)	$27.8	4.5%
3	Cumberland - Juniata	Line	PPL	$2.4	($22.4)	$1.5	$26.4	($0.2)	($0.7)	($2.0)	($1.5)	$24.8	4.0%
4	Graceton - Safe Harbor	Line	BGE	$23.3	$0.8	$2.1	$24.6	$1.3	$1.0	($0.8)	($0.5)	$24.1	3.9%
5	Bagley - Raphael Road	Line	BGE	$18.9	($2.7)	$1.7	$23.4	$1.7	$2.2	($2.1)	($2.5)	$20.9	3.4%
6	Brambleton - Evergreen Mills	Line	DOM	$7.0	($13.5)	$0.4	$20.9	$0.0	($0.2)	($0.6)	($0.4)	$20.5	3.3%
7	Pleasant View	Transformer	DOM	$4.4	($18.6)	$0.5	$23.4	$1.3	$2.2	($2.3)	($3.2)	$20.3	3.3%
8	Nottingham	Other	PECO	$20.9	$3.1	$2.5	$20.3	$1.2	$0.9	($0.6)	($0.3)	$20.0	3.3%
9	Harwood - Susquehanna	Line	PPL	$3.7	($16.3)	$0.8	$20.8	($0.2)	$0.9	($0.9)	($2.0)	$18.8	3.1%
10	Conastone	Transformer	500	$8.8	($7.9)	$0.2	$16.9	$0.1	$0.3	($0.2)	($0.4)	$16.5	2.7%
11	Vienna	Transformer	DPL	$13.4	($8.3)	$0.6	$22.3	($9.6)	($2.2)	$0.4	($7.0)	$15.3	2.5%
12	Brighton	Other	500	$14.5	$2.1	$1.2	$13.6	$4.6	$3.3	($1.7)	($0.4)	$13.2	2.1%
13	Rappahanock - White Stone	Line	DOM	$33.2	$18.7	$1.6	$16.0	($2.7)	($0.7)	($1.5)	($3.5)	$12.5	2.0%
14	Conastone - Northwest	Line	BGE	$7.1	($5.2)	$0.3	$12.6	$0.5	$0.4	($0.2)	($0.1)	$12.5	2.0%
15	Bagley - Graceton	Line	BGE	$8.7	($1.6)	$0.5	$10.7	$0.3	$0.6	($0.0)	($0.4)	$10.4	1.7%
16	East Lima - Haviland	Line	AEP	($19.5)	($29.7)	$1.1	$11.2	($0.4)	$0.7	($0.5)	($1.5)	$9.7	1.6%
17	Juniata	Transformer	500	$2.1	($6.9)	($0.3)	$8.8	($0.1)	($0.1)	$0.1	$0.1	$8.9	1.4%
18	Ashburn - Cochran Mill	Line	DOM	$7.8	($0.0)	$0.4	$8.2	$0.2	$0.2	($0.3)	($0.3)	$7.9	1.3%
19	Five Forks - Rock Ridge Tap	Line	BGE	$2.2	($4.7)	$0.5	$7.5	$0.2	$0.4	($0.1)	($0.3)	$7.2	1.2%
20	Cedar Grove Sub - William	Line	PSEG	$8.7	($9.6)	$5.2	$23.5	($9.9)	$9.0	($11.7)	($30.6)	($7.1)	(1.2%)
21	Gardners - Texas Eastern	Line	MEC	($3.0)	($9.9)	$0.0	$7.0	($0.3)	$0.1	($0.0)	($0.4)	$6.5	1.1%
22	Preston - Tanyard	Line	DPL	$8.7	$2.6	$0.7	$6.8	($0.2)	$0.1	$0.0	($0.3)	$6.5	1.1%
23	Bergenfield - Leonia	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($3.4)	$1.1	($1.9)	($6.4)	($6.4)	(1.0%)
24	Lenox - North Meshoppen	Line	PE	$0.1	($7.2)	$0.6	$8.0	$0.4	$1.5	($0.8)	($1.9)	$6.1	1.0%
25	Keeney	Transformer	DPL	$5.6	$0.2	$0.2	$5.5	$0.4	($0.2)	($0.2)	$0.4	$6.0	1.0%
	Top 25 Total			$237.3	($169.3)	$24.8	$431.4	($13.9)	$18.8	($30.2)	($62.8)	$368.6	60.0%
	All Other Constraints			$87.2	($244.0)	$26.9	$358.1	($13.0)	$48.7	($50.4)	($112.1)	$246.0	40.0%
	Total			$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$614.6	100.0%

Figure 11-4 shows the hourly total congestion costs of the top five constraints in the first nine months of 2022. Three of the top five constraints were in the DOM zone as a result of increased load in the Data Center Alley area of Northern Virginia (The Brambleton - Evergreen Mills Line, the Cumberland – Juniata Line, the Beaumeade Circuit Breaker and the Idylwood – Clark). The increased load in the DOM Zone resulted in the dispatch of more expensive generation units to control the affected constraints. These three constraints also had 20 hours of transmission constraint penalty factors in the day-ahead market which added to the high congestion costs.

32 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless the location of the flowgates.

Figure 11-4 Top five constraints affecting total congestion costs: January through September, 2022

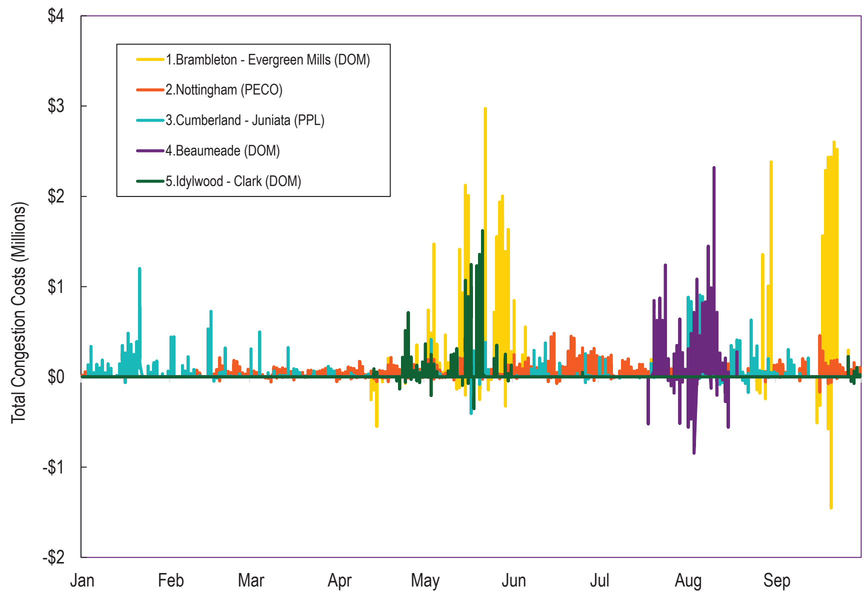


Figure 11-5 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first nine months of 2022.

Figure 11-5 Location of the top 10 constraints by total congestion costs: January through September, 2022

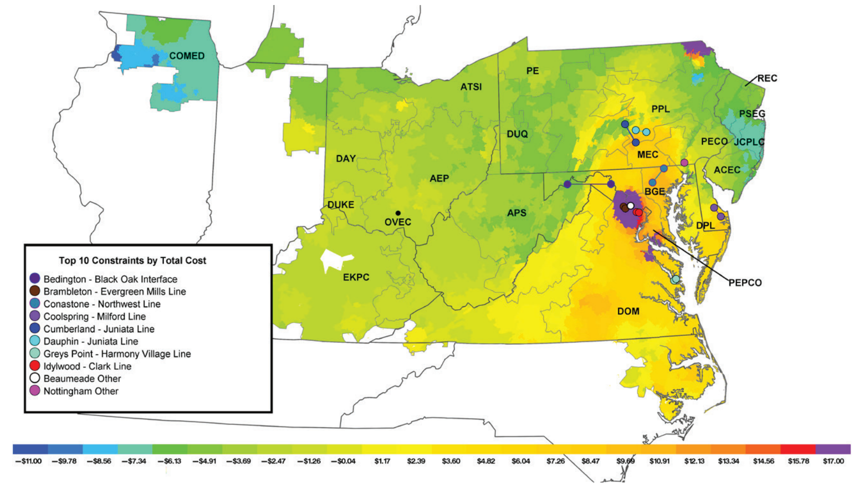


Figure 11-6 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in the first nine months of 2022.

Figure 11-6 Location of top 10 constraints by balancing congestion costs: January through September, 2022

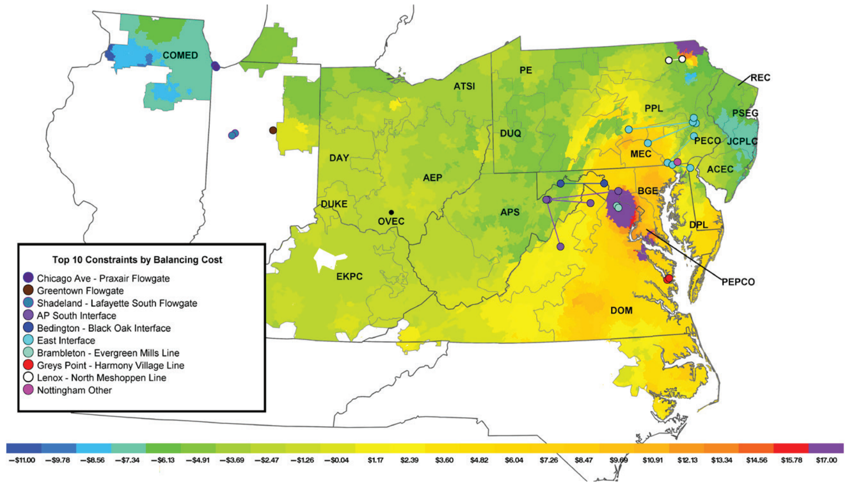
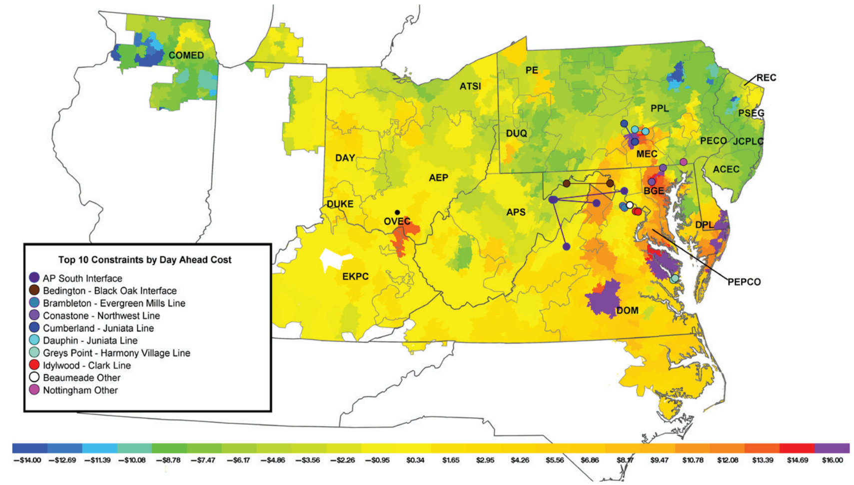


Figure 11-7 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in the first nine months of 2022.

Figure 11-7 Location of the top 10 constraints by day-ahead congestion costs: January through September, 2022



Comparing Figure 11-6 (Location of the top 10 constraints by balancing congestion costs) and Figure 11-7 (location of the top 10 constraints by day ahead congestion costs) shows the significant differences between the day ahead and real time market.

Congestion Event Summary: Impact of Changes in UTC Volumes

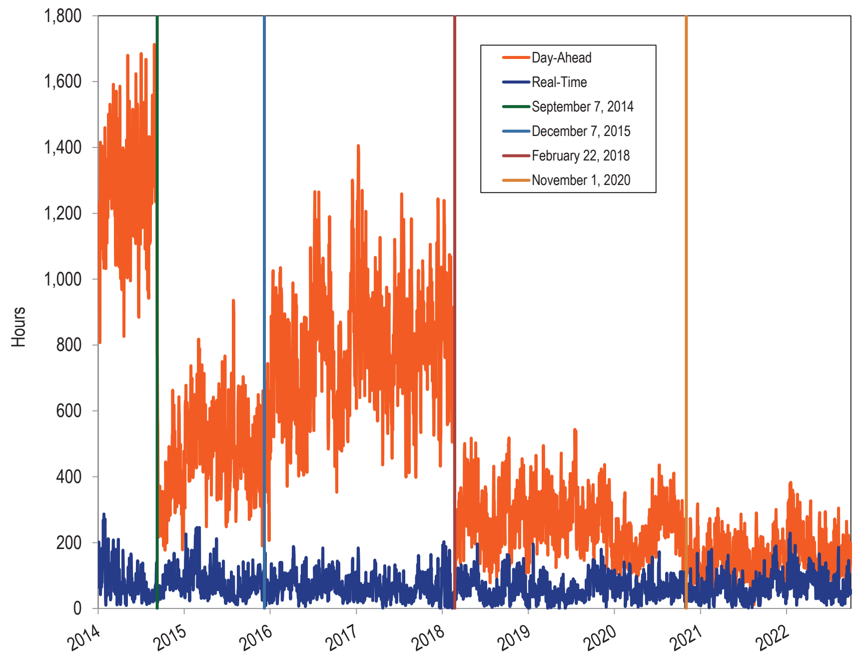
UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[33]

33 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

In the first nine months of 2022, the average hourly cleared UTC MW increased by 49.1 percent, compared to the first nine months of 2021. Day-ahead congestion event hours 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 (Table 11-25).

Figure 11-8 shows the daily day-ahead and real-time congestion event hours for January 2014 through September 2022.

Figure 11-8 Daily congestion event hours: January 2014 through September 2022



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the day-ahead and real-time energy markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[34] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[35] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

34 PJM Operating Agreement Schedule 1 §3.7.
35 *Id.*

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load weighted reference bus is the marginal cost of energy at the load weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load weighted average MLMP across all load buses, calculated relative to that reference bus is positive. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss. That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the day-ahead and real-time energy markets priced at the marginal loss price component of LMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[36]

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Implicit Load MLMP Charges.** Balancing implicit load MLMP charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load plus export ratio basis.[37]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for the first nine months of 2022 was $1,472.0 million, which was comprised of implicit load MLMP charges of $132.6 million minus implicit generation MLMP credits of -$1,373.8 million plus explicit loss charges of -$34.3 million plus inadvertent loss charges of $0.0 million (Table 11-34).

Monthly marginal loss costs in the first nine months of 2022 ranged from $85.7 million in March to $257.4 million in August. Total marginal loss surplus increased in the first nine months of 2022 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.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for the first nine months of 2008 through 2022.

36 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 89 (Nov. 1, 2022).

37 PJM Operating Agreement Schedule 1 §3.7.

Table 11-33 Total loss component costs (Dollars (Millions)): January through September, 2008 through 2022[38] [39]

(Jan - Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,049	NA	$26,979	7.6%
2009	$992	(51.6%)	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,770	3.0%
2015	$830	(33.3%)	$33,710	2.5%
2016	$542	(34.7%)	$29,490	1.8%
2017	$501	(7.5%)	$29,510	1.7%
2018	$757	51.1%	$37,950	2.0%
2019	$503	(33.6%)	$31,850	1.6%
2020	$349	(30.5%)	$27,050	1.3%
2021	$670	91.9%	$37,550	1.8%
2022	$1,472	119.6%	$66,100	2.2%

Table 11-34 shows PJM total marginal loss costs by accounting category for January through September, 2008 through 2022. Table 11-35 shows PJM total marginal loss costs by accounting category by market for January through September, 2008 through 2022.

Table 11-34 Total marginal loss costs by accounting category (Dollars (Millions)): January through September, 2008 through 2022

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($210.3)	($2,185.9)	$73.3	$0.0	$2,048.9
2009	($62.0)	($1,028.3)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($52.9)	$0.0	$1,243.1
2015	($26.1)	($872.8)	($16.9)	$0.0	$829.8
2016	($41.7)	($605.4)	($21.8)	($0.0)	$541.9
2017	($38.6)	($568.1)	($28.4)	$0.0	$501.0
2018	($32.7)	($798.6)	($8.9)	$0.0	$757.0
2019	($35.5)	($550.1)	($12.0)	$0.0	$502.7
2020	($25.8)	($387.4)	($12.4)	$0.0	$349.2
2021	$3.3	($673.5)	($6.7)	$0.0	$670.2
2022	$132.6	($1,373.8)	($34.3)	($0.0)	$1,472.0

38 The loss costs include net inadvertent charges.
39 In Table 11-33, 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.

Table 11-35 Total marginal loss costs by market (Dollars (Millions)): January through September, 2008 through 2022

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($132.3)	($2,133.4)	$100.8	$2,101.8	($77.9)	($52.5)	($27.4)	($52.9)	$0.0	$2,048.9
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.9	($2.6)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1
2015	($47.0)	($883.1)	$24.7	$860.8	$20.9	$10.3	($41.6)	($31.0)	$0.0	$829.8
2016	($48.4)	($606.0)	$37.8	$595.4	$6.6	$0.5	($59.5)	($53.4)	($0.0)	$541.9
2017	($45.9)	($568.9)	$43.1	$566.0	$7.3	$0.8	($71.5)	($65.0)	$0.0	$501.0
2018	($38.5)	($790.8)	$28.6	$780.9	$5.8	($7.8)	($37.5)	($23.9)	$0.0	$757.0
2019	($37.4)	($547.8)	$32.2	$542.6	$1.9	($2.3)	($44.2)	($39.9)	$0.0	$502.7
2020	($27.8)	($388.8)	$30.5	$391.5	$2.0	$1.4	($42.9)	($42.3)	$0.0	$349.2
2021	$2.0	($668.7)	$24.7	$695.4	$1.3	($4.9)	($31.4)	($25.2)	$0.0	$670.2
2022	$136.8	($1,371.2)	$65.6	$1,573.6	($4.2)	($2.6)	($99.9)	($101.5)	($0.0)	$1,472.0

Table 11-36 and Table 11-37 show PJM accounting based total loss costs for each transaction type in the first nine months of 2022 and 2021.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transactions. In the first nine months of 2022, DECs paid $3.8 million in MLMP charges in the day-ahead market, paid $5.6 million in MLMP in the balancing energy market and paid $9.4 million in total MLMP charges. In the first nine months of 2022, INCs paid $28.3 million in MLMP charges in the day-ahead market, were paid $40.1 million in MLMP credits in the balancing energy market and were paid $11.8 million in total MLMP credits. In the first nine months of 2022, up to congestion paid $67.8 million in MLMP charges in the day-ahead market, were paid $99.7 million in MLMP credits in the balancing energy market and received $31.9 million in total MLMP credits.

Table 11-36 Total loss costs by transaction type (Dollars (Millions)): January through September, 2022

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$3.8	$0.0	$0.0	$3.8	$5.6	$0.0	$0.0	$5.6	$0.0	$9.4
Demand	$104.3	$0.0	$0.0	$104.3	$16.4	$0.0	$0.0	$16.4	$0.0	$120.7
Demand Response	$0.1	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.0	($0.1)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($2.8)	($2.8)	$0.0	$0.0	$0.0	$0.0	$0.0	($2.7)
Export	($24.7)	$0.0	($0.3)	($25.0)	($20.0)	$0.0	($0.1)	($20.1)	$0.0	($45.1)
Generation	$0.0	($1,392.4)	$0.0	$1,392.4	$0.0	($18.4)	$0.0	$18.4	$0.0	$1,410.8
Import	$0.0	($4.6)	$0.0	$4.6	$0.0	($18.3)	$0.0	$18.3	$0.0	$22.9
INC	$0.0	($28.3)	$0.0	$28.3	$0.0	$40.1	$0.0	($40.1)	$0.0	($11.8)
Internal Bilateral	$53.3	$54.1	$0.9	($0.0)	($6.1)	($6.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$67.8	$67.8	$0.0	$0.0	($99.7)	($99.7)	$0.0	($31.9)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.2)
Total	$136.8	($1,371.2)	$65.6	$1,573.6	($4.2)	($2.6)	($99.9)	($101.5)	$0.0	$1,472.0

Table 11-37 Total loss costs by transaction type (Dollars (Millions)): January through September, 2021

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$0.9	$0.0	$0.0	$0.9	$1.9	$0.0	$0.0	$1.9	$0.0	$2.8
Demand	$18.6	$0.0	$0.0	$18.6	$5.9	$0.0	$0.0	$5.9	$0.0	$24.5
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.8)	($0.8)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.8)
Export	($13.7)	$0.0	($0.1)	($13.8)	($5.3)	$0.0	$0.2	($5.1)	$0.0	($18.9)
Generation	$0.0	($655.8)	$0.0	$655.8	$0.0	($11.7)	$0.0	$11.7	$0.0	$667.5
Import	$0.0	($1.0)	$0.0	$1.0	$0.0	($2.1)	$0.0	$2.1	$0.0	$3.1
INC	$0.0	($8.3)	$0.0	$8.3	$0.0	$10.1	$0.0	($10.1)	$0.0	($1.8)
Internal Bilateral	($3.8)	($3.6)	$0.3	($0.0)	($1.2)	($1.2)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$25.3	$25.3	$0.0	$0.0	($31.6)	($31.6)	$0.0	($6.3)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Total	$2.0	($668.7)	$24.7	$695.4	$1.3	($4.9)	($31.4)	($25.2)	$0.0	$670.2

Table 11-38 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in the first nine months of 2022. Total MLMP charges to generation increased by $3.4 million, and total MLMP charges to demand increased by $1.6 million from the dispatch run to the pricing run. The total MLMP charges to DECs increased by $0.3 million, the total MLMP credits to INCs increased by $2.2 million and the total CLMP credits to UTCs increased by $5.8 million from the dispatch run to the pricing run.

Table 11-38 Total loss costs by dispatch and pricing run (Dollars (Millions)): January through September, 2022

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$3.8	$5.3	$9.1	$3.8	$5.6	$9.4	$0.0	$0.2	$0.3
Demand	$104.1	$15.0	$119.1	$104.3	$16.4	$120.7	$0.2	$1.4	$1.6
Demand Response	$0.1	($0.1)	$0.0	$0.1	($0.1)	$0.0	($0.0)	($0.0)	($0.0)
Explicit Congestion and Loss Only	($2.8)	$0.0	($2.7)	($2.8)	$0.0	($2.7)	($0.0)	$0.0	($0.0)
Export	($25.0)	($19.0)	($44.0)	($25.0)	($20.1)	($45.1)	$0.0	($1.1)	($1.1)
Generation	$1,389.7	$17.8	$1,407.4	$1,392.4	$18.4	$1,410.8	$2.8	$0.6	$3.4
Import	$4.6	$17.1	$21.7	$4.6	$18.3	$22.9	$0.0	$1.1	$1.1
INC	$28.3	($37.9)	($9.6)	$28.3	($40.1)	($11.8)	$0.0	($2.2)	($2.2)
Internal Bilateral	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)
Up to Congestion	$67.7	($93.8)	($26.1)	$67.8	($99.7)	($31.9)	$0.1	($5.9)	($5.8)
Wheel In	$0.0	($0.2)	($0.2)	$0.0	($0.2)	($0.2)	$0.0	($0.0)	($0.0)
Total	$1,570.4	($95.7)	$1,474.7	$1,573.6	($101.5)	$1,472.0	$3.2	($5.9)	($2.7)

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for January 2021 through September 2022.

Table 11-39 Monthly marginal loss costs (Millions): January 2021 through September 2022

	Marginal Loss Costs (Millions)							
	2021				2022			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$62.0	($2.1)	($0.0)	$59.9	$213.0	($18.4)	$0.0	$194.6
Feb	$107.7	($5.1)	$0.0	$102.7	$120.9	($8.1)	$0.0	$112.8
Mar	$50.8	($3.7)	$0.0	$47.2	$91.5	($5.8)	($0.0)	$85.7
Apr	$44.4	($1.8)	($0.0)	$42.5	$103.6	($4.1)	($0.0)	$99.5
May	$53.4	($3.0)	$0.0	$50.4	$155.8	($8.4)	($0.0)	$147.4
Jun	$76.1	($2.8)	$0.0	$73.3	$188.0	($10.1)	($0.0)	$177.9
Jul	$98.5	($2.5)	$0.0	$96.1	$253.2	($14.7)	$0.0	$238.5
Aug	$113.6	($0.8)	$0.0	$112.8	$276.9	($19.5)	($0.0)	$257.4
Sep	$88.9	($3.5)	$0.0	$85.4	$170.7	($12.5)	($0.0)	$158.2
Oct	$98.6	($2.7)	($0.0)	$95.9				
Nov	$116.5	($4.0)	$0.0	$112.4				
Dec	$77.4	($1.2)	($0.0)	$76.3				
Total	$987.9	($33.1)	$0.0	$954.8	$1,573.6	($101.5)	($0.0)	$1,472.0

Figure 11-9 shows PJM monthly marginal loss costs for 2008 through September 2022.

Figure 11-9 Monthly marginal loss cost (Dollars (Millions)): January 2008 through September 2022

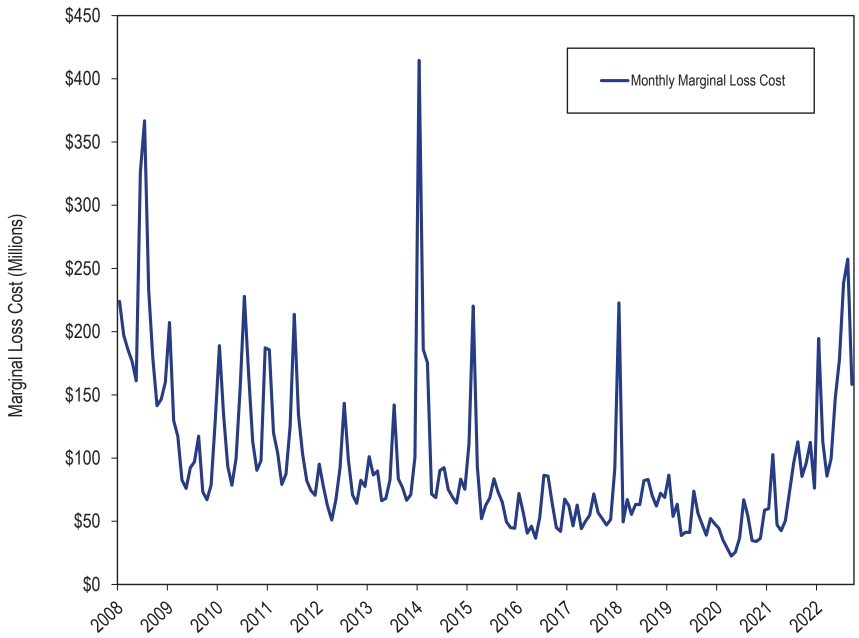


Table 11-40 shows the monthly total loss charges for each virtual transaction type for January 2021 through September 2022.

Table 11-40 Monthly loss charges by virtual transaction type (Dollars (Millions)): January 2021 through September 2022

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2021	Jan	$0.3	($0.1)	$0.2	$0.8	($1.1)	($0.3)	$2.2	($2.6)	($0.4)	($0.5)
	Feb	$1.1	($0.7)	$0.4	$0.8	($0.9)	($0.1)	$4.5	($4.7)	($0.2)	$0.1
	Mar	$0.2	$0.2	$0.4	$1.2	($1.3)	($0.2)	$2.5	($3.2)	($0.7)	($0.5)
	Apr	($0.3)	$0.3	$0.1	$1.2	($1.1)	$0.0	$1.8	($2.2)	($0.4)	($0.2)
	May	($0.0)	$0.1	$0.0	$1.0	($1.1)	($0.1)	$2.5	($3.2)	($0.7)	($0.7)
	Jun	$0.1	$0.1	$0.2	$0.7	($1.0)	($0.2)	$3.2	($4.2)	($1.1)	($1.0)
	Jul	($0.1)	$0.5	$0.5	$0.8	($0.9)	($0.1)	$3.6	($3.8)	($0.2)	$0.1
	Aug	($0.4)	$1.2	$0.8	$0.6	($1.1)	($0.4)	$2.5	($3.1)	($0.6)	($0.3)
	Sep	($0.1)	$0.3	$0.2	$1.1	($1.7)	($0.5)	$2.5	($4.5)	($2.0)	($2.3)
	Oct	($1.1)	$0.9	($0.2)	$1.6	($1.9)	($0.3)	$2.5	($3.4)	($1.0)	($1.4)
	Nov	($0.6)	$0.8	$0.2	$2.9	($3.5)	($0.6)	$4.6	($5.4)	($0.8)	($1.1)
	Dec	($0.3)	$0.8	$0.5	$1.0	($1.5)	($0.5)	$1.9	($2.7)	($0.8)	($0.7)
	Total	($1.0)	$4.5	$3.4	$13.8	($17.0)	($3.2)	$34.3	($43.0)	($8.8)	($8.5)
2022	Jan	$6.8	($5.6)	$1.2	$2.9	($4.9)	($2.0)	$7.2	($10.4)	($3.1)	($3.9)
	Feb	$5.1	($1.9)	$3.3	$1.7	($3.0)	($1.3)	$5.7	($7.8)	($2.1)	($0.1)
	Mar	$0.3	$0.6	$0.9	$2.5	($3.5)	($1.0)	$2.8	($5.6)	($2.8)	($3.0)
	Apr	($0.9)	$1.2	$0.3	$3.4	($4.3)	($0.9)	$4.0	($5.7)	($1.7)	($2.3)
	May	($1.6)	$1.8	$0.2	$4.5	($4.7)	($0.2)	$7.6	($9.0)	($1.4)	($1.4)
	Jun	($2.3)	$2.6	$0.3	$2.9	($4.9)	($1.9)	$8.5	($14.2)	($5.7)	($7.3)
	Jul	($1.3)	$2.4	$1.1	$3.7	($5.1)	($1.4)	$10.3	($14.8)	($4.5)	($4.8)
	Aug	($0.8)	$2.2	$1.5	$3.6	($6.1)	($2.5)	$12.6	($20.0)	($7.4)	($8.5)
	Sep	($1.6)	$2.2	$0.7	$3.0	($3.5)	($0.6)	$9.0	($12.1)	($3.1)	($3.0)
	Total	$3.8	$5.6	$9.4	$28.3	($40.1)	($11.8)	$67.8	($99.7)	($31.9)	($34.3)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-41 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through September, 2008 through 2022. The total marginal loss surplus increased by $250.6 million or 105.7 percent in the first nine months of 2022 from the first nine months of 2021.

Table 11-41 Marginal loss surplus (Dollars (Millions)): January through September, 2008 through 2022[40]

	Marginal Loss Surplus (Millions)					
			Net Residual Market Adjustments			
(Jan - Sep)	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($976.0)	$2,048.9	$0.0	$0.0	$0.0	$1,073.0
2009	($484.6)	$992.4	($0.0)	($0.4)	($0.1)	$508.3
2010	($618.6)	$1,259.3	$0.0	($0.6)	($0.1)	$641.5
2011	($651.3)	$1,152.6	$0.1	$1.3	($0.0)	$500.1
2012	($442.6)	$757.6	$0.1	($0.7)	$0.0	$315.7
2013	($527.2)	$797.0	$0.0	$1.7	$0.0	$268.0
2014	($833.9)	$1,243.1	($0.0)	$5.1	$0.1	$404.1
2015	($536.5)	$829.8	($0.3)	$4.7	($0.1)	$288.3
2016	($358.3)	$541.9	$0.0	$2.8	($0.2)	$181.0
2017	($344.0)	$501.0	$0.0	$0.7	($0.1)	$156.5
2018	($498.7)	$757.0	($0.0)	$1.9	($0.1)	$256.4
2019	($339.3)	$502.7	($0.0)	$1.3	($0.1)	$162.1
2020	($234.0)	$349.2	($0.0)	$1.1	($0.1)	$114.2
2021	($430.7)	$670.2	($0.0)	$2.5	($0.1)	$237.0
2022	($979.1)	$1,472.0	($0.0)	$5.6	($0.2)	$487.6

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs.

Total System Energy Costs

The total system energy cost for the first nine months of 2022 was -$979.1 million, which was comprised of implicit withdrawal energy charges of $64,425.9 million, implicit injection energy credits of $65,400.0 million, explicit energy charges of $0.0 million and inadvertent energy charges of -$5.0 million. The monthly system energy costs for the first nine months of 2022 ranged from -$168.6 million in August to -$60.0 million in March.

Table 11-42 shows total system energy costs and total PJM billing, for January through September, 2008 through 2022.

Table 11-42 Total system energy costs (Dollars (Millions)): January through September, 2008 through 2022[41 42]

(Jan - Sep)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($976)	NA	$26,979	(3.6%)
2009	($485)	(50.3%)	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,770	(2.0%)
2015	($537)	(35.7%)	$33,710	(1.6%)
2016	($358)	(33.2%)	$29,490	(1.2%)
2017	($344)	(4.0%)	$29,510	(1.2%)
2018	($499)	45.0%	$37,950	(1.3%)
2019	($339)	(32.0%)	$31,850	(1.1%)
2020	($234)	(31.0%)	$27,050	(0.9%)
2021	($431)	84.0%	$37,550	(1.1%)
2022	($979)	127.3%	$66,100	(1.5%)

System energy costs for January through September, 2008 through 2022 are shown in Table 11-43 and Table 11-44. Table 11-43 shows PJM system energy costs by accounting category and Table 11-44 shows PJM system energy costs by market category.

40 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

41 The system energy costs include net inadvertent charges.

42 In Table 11-42, 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.

Table 11-43 Total system energy costs by accounting category (Dollars (Millions)): January through September, 2008 through 2022

(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
	System Energy Costs (Millions)				
2008	$91,391.9	$92,368.9	$0.0	$1.0	($976.0)
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)
2015	$33,772.7	$34,311.9	$0.0	$2.6	($536.5)
2016	$25,858.3	$26,213.7	$0.0	($2.9)	($358.3)
2017	$26,082.1	$26,430.6	$0.0	$4.5	($344.0)
2018	$33,871.7	$34,376.1	$0.0	$5.7	($498.7)
2019	$23,696.4	$24,035.9	$0.0	$0.2	($339.3)
2020	$17,364.8	$17,600.7	$0.0	$1.9	($234.0)
2021	$28,853.8	$29,288.0	$0.0	$3.5	($430.7)
2022	$64,425.9	$65,400.0	$0.0	($5.0)	($979.1)

Table 11-44 Total system energy costs by market (Dollars (Millions)): January through September, 2008 through 2022

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$67,568.7	$68,653.8	$0.0	($1,085.1)	$23,823.2	$23,715.1	$0.0	$108.1	$1.0	($976.0)
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)
2015	$33,910.7	$34,549.7	$0.0	($639.0)	($138.0)	($237.8)	$0.0	$99.8	$2.6	($536.5)
2016	$25,986.4	$26,469.9	$0.0	($483.5)	($128.1)	($256.2)	$0.0	$128.1	($2.9)	($358.3)
2017	$26,360.1	$26,844.5	$0.0	($484.4)	($278.0)	($413.9)	$0.0	$135.9	$4.5	($344.0)
2018	$33,957.1	$34,508.6	$0.0	($551.4)	($85.4)	($132.5)	$0.0	$47.1	$5.7	($498.7)
2019	$24,004.0	$24,411.6	$0.0	($407.6)	($307.7)	($375.7)	$0.0	$68.0	$0.2	($339.3)
2020	$17,564.2	$17,867.8	$0.0	($303.6)	($199.4)	($267.1)	$0.0	$67.7	$1.9	($234.0)
2021	$28,994.9	$29,470.3	$0.0	($475.4)	($141.2)	($182.4)	$0.0	$41.2	$3.5	($430.7)
2022	$64,959.1	$66,075.9	$0.0	($1,116.7)	($533.3)	($675.9)	$0.0	$142.6	($5.0)	($979.1)

Table 11-45 and Table 11-46 show the total system energy costs for each transaction type in the first nine months of 2022 and 2021. In the first nine months of 2022, generation was paid $48,288.3 million and demand paid $45,547.2 million in net energy payment. In the first nine months of 2021, generation was paid $22,215.8 million and demand paid $20,733.9 million in net energy payment.

Table 11-45 Total system energy costs by transaction type (Dollars (Millions)): January through September, 2022

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$2,594.6	$0.0	$0.0	$2,594.6	($2,625.4)	$0.0	$0.0	($2,625.4)	($30.8)
Demand	$44,641.0	$0.0	$0.0	$44,641.0	$906.2	$0.0	$0.0	$906.2	$45,547.2
Demand Response	($6.0)	$0.0	$0.0	($6.0)	$6.0	$0.0	$0.0	$6.0	$0.1
Export	$1,615.1	$0.0	$0.0	$1,615.1	$1,001.1	$0.0	$0.0	$1,001.1	$2,616.1
Generation	$0.0	$48,166.7	$0.0	($48,166.7)	$0.0	$121.6	$0.0	($121.6)	($48,288.3)
Import	$0.0	$155.9	$0.0	($155.9)	$0.0	$675.2	$0.0	($675.2)	($831.1)
INC	$0.0	$1,638.8	$0.0	($1,638.8)	$0.0	($1,651.5)	$0.0	$1,651.5	$12.6
Internal Bilateral	$16,114.5	$16,114.5	$0.0	$0.0	$160.7	$160.7	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$18.1	$0.0	($18.1)	($18.1)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$18.1	$0.0	$0.0	$18.1	$18.1
Total	$64,959.1	$66,075.9	$0.0	($1,116.7)	($533.3)	($675.9)	$0.0	$142.6	($974.1)

Table 11-46 Total system energy costs by transaction type by (Dollars (Millions)): January through September, 2021

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$1,010.2	$0.0	$0.0	$1,010.2	($1,023.3)	$0.0	$0.0	($1,023.3)	($13.0)
Demand	$20,380.6	$0.0	$0.0	$20,380.6	$353.3	$0.0	$0.0	$353.3	$20,733.9
Demand Response	($0.7)	$0.0	$0.0	($0.7)	$0.7	$0.0	$0.0	$0.7	($0.0)
Export	$736.5	$0.0	$0.0	$736.5	$481.1	$0.0	$0.0	$481.1	$1,217.5
Generation	$0.0	$22,050.5	$0.0	($22,050.5)	$0.0	$165.3	$0.0	($165.3)	($22,215.8)
Import	$0.0	$39.2	$0.0	($39.2)	$0.0	$120.7	$0.0	($120.7)	($159.9)
INC	$0.0	$512.3	$0.0	($512.3)	$0.0	($515.4)	$0.0	$515.4	$3.2
Internal Bilateral	$6,868.4	$6,868.4	$0.0	$0.0	$36.0	$36.0	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$11.0	$0.0	($11.0)	($11.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$11.0	$0.0	$0.0	$11.0	$11.0
Total	$28,994.9	$29,470.3	$0.0	($475.4)	($141.2)	($182.4)	$0.0	$41.2	($434.2)

Table 11-47 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in the first nine months of 2022. The system energy charges to demand increased $154.7 million, and the energy credits to generation increased $105.3 million from the dispatch run to the pricing run. The energy credits to DEC increased $145.7 million, the energy charges to INC increased $87.4 million from the dispatch run to the pricing run.

Table 11-47 Total system energy costs by dispatch and pricing run (Dollars (Millions)): January through September, 2022

System Energy Costs (Millions)									
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$2,588.4	($2,473.5)	$114.9	$2,594.6	($2,625.4)	($30.8)	$6.2	($151.9)	($145.7)
Demand	$44,547.7	$844.8	$45,392.5	$44,641.0	$906.2	$45,547.2	$93.3	$61.4	$154.7
Demand Response	($5.9)	$5.4	($0.5)	($6.0)	$6.0	$0.1	($0.0)	$0.6	$0.6
Export	$1,611.4	$952.3	$2,563.7	$1,615.1	$1,001.1	$2,616.1	$3.7	$48.8	$52.5
Generation	($48,064.5)	($118.4)	($48,182.9)	($48,166.7)	($121.6)	($48,288.3)	($102.2)	($3.1)	($105.3)
Import	($155.7)	($636.4)	($792.1)	($155.9)	($675.2)	($831.1)	($0.2)	($38.8)	($39.0)
INC	($1,635.8)	$1,561.0	($74.8)	($1,638.8)	$1,651.5	$12.6	($3.0)	$90.4	$87.4
Internal Bilateral	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0
Wheel In	$0.0	($17.4)	($17.4)	$0.0	($18.1)	($18.1)	$0.0	($0.7)	($0.7)
Wheel Out	$0.0	$17.4	$17.4	$0.0	$18.1	$18.1	$0.0	$0.7	$0.7
Total	($1,114.5)	$135.2	($979.3)	($1,116.7)	$142.6	($974.1)	($2.2)	$7.4	$5.2

Monthly System Energy Costs

Table 11-48 shows a monthly summary of system energy costs by market type for January 2021 through September 2022. Total balancing system energy costs in 2022 increased in every month except for February and March compared to the first nine months of 2021. 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.

Table 11-48 Monthly system energy costs (Dollars (Millions)): January 2021 through September 2022

System Energy Costs (Millions)								
	2021				2022			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($42.7)	$5.0	($0.1)	($37.8)	($139.7)	$13.2	($0.1)	($126.5)
Feb	($73.5)	$9.8	$0.7	($63.0)	($74.7)	$0.5	($0.1)	($74.3)
Mar	($35.8)	$5.1	$0.0	($30.7)	($64.7)	$4.9	($0.3)	($60.0)
Apr	($30.4)	$2.1	($0.1)	($28.4)	($78.1)	$9.0	($1.1)	($70.2)
May	($37.8)	$4.6	$0.1	($33.1)	($114.4)	$15.7	($0.4)	($99.1)
Jun	($52.8)	$5.0	$0.3	($47.5)	($138.0)	$17.1	($0.7)	($121.6)
Jul	($65.3)	$4.6	$0.8	($59.9)	($177.8)	$22.4	$0.6	($154.9)
Aug	($75.6)	$1.1	$1.5	($73.0)	($201.6)	$34.1	($1.1)	($168.6)
Sep	($61.5)	$3.9	$0.3	($57.3)	($127.7)	$25.7	($1.9)	($103.9)
Oct	($68.8)	$5.8	($0.3)	($63.4)				
Nov	($79.6)	$2.5	($0.2)	($77.3)				
Dec	($54.4)	$2.8	($0.3)	($51.8)				
Total	($678.2)	$52.3	$2.7	($623.2)	($1,116.7)	$142.6	($5.0)	($979.1)

Figure 11-10 shows PJM monthly system energy costs for January through September, 2008 through 2022. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0.) Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-10 Monthly system energy costs (Millions): January 2008 through September 2022

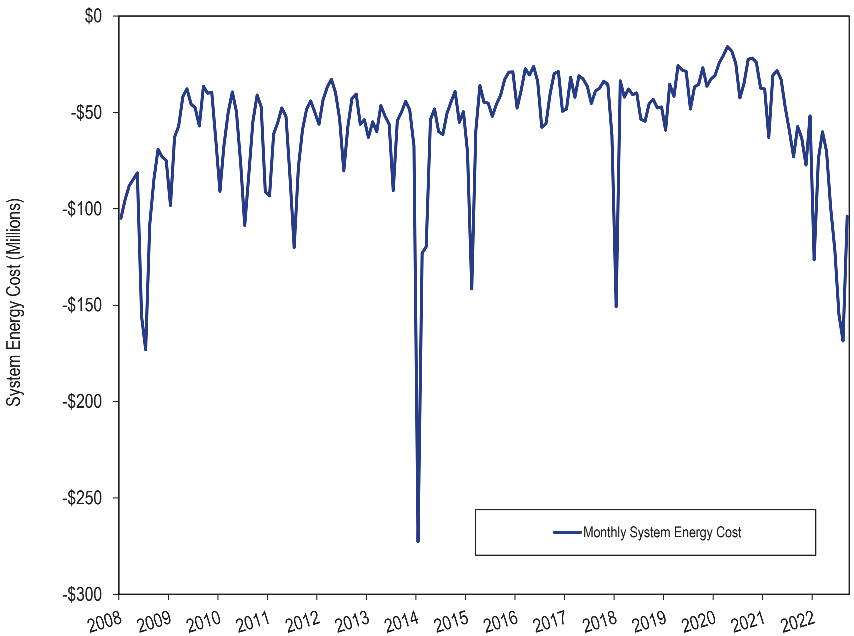


Table 11-49 shows the monthly total system energy costs for each virtual transaction type in the first nine months of 2022 and year of 2021. In the first nine months of 2022, DECs paid $2,594.6 million in energy charges in the day-ahead market, were paid $2,625.4 million in energy credits in the balancing energy market and were paid $30.8 million in total energy credits. In the first nine months of 2022, INCs were paid $1,638.8 million in energy credits in the day-ahead market, paid $1,651.5 million in energy charges in the balancing market and paid $12.6 million in total energy charges. In the first nine months of 2021, DECs paid $1,010.2 million in energy charges in the day-ahead market, were paid $1,023.3 million in energy credits in the balancing energy market and were paid $13.0 million in total energy credits. In the first nine months of 2021, INCs were paid $512.3 million in energy credits in the day-ahead market, paid $515.4 million in energy charges in the balancing energy market and paid $3.2 million in total energy charges. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-49 Monthly energy charges by virtual transaction type (Dollars (Millions)): January 2021 through September 2022

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2021	Jan	$76.5	($76.2)	$0.3	($41.9)	$41.6	($0.3)	($0.0)
	Feb	$167.0	($157.6)	$9.4	($54.4)	$51.4	($3.0)	$6.5
	Mar	$83.8	($89.0)	($5.2)	($50.9)	$53.3	$2.4	($2.8)
	Apr	$73.2	($70.5)	$2.7	($62.3)	$60.6	($1.7)	$1.0
	May	$81.7	($81.3)	$0.5	($52.7)	$52.5	($0.2)	$0.2
	Jun	$123.2	($127.6)	($4.4)	($46.1)	$46.5	$0.4	($4.0)
	Jul	$117.8	($113.7)	$4.1	($67.8)	$64.9	($2.9)	$1.3
	Aug	$145.0	($154.3)	($9.3)	($65.3)	$68.8	$3.5	($5.8)
	Sep	$142.0	($153.1)	($11.1)	($70.9)	$75.7	$4.8	($6.3)
	Oct	$179.4	($180.4)	($1.0)	($87.0)	$87.5	$0.5	($0.5)
	Nov	$175.3	($180.3)	($5.1)	($114.1)	$116.3	$2.3	($2.8)
	Dec	$153.5	($160.9)	($7.4)	($64.0)	$66.0	$2.0	($5.4)
	Total	$1,518.4	($1,544.8)	($26.4)	($777.3)	$785.2	$7.9	($18.5)
2022	Jan	$312.1	($344.7)	($32.5)	($133.4)	$147.1	$13.7	($18.9)
	Feb	$207.9	($196.5)	$11.4	($119.5)	$111.8	($7.6)	$3.7
	Mar	$193.0	($183.9)	$9.1	($133.1)	$128.2	($4.9)	$4.2
	Apr	$180.0	($177.9)	$2.1	($179.0)	$177.1	($1.9)	$0.2
	May	$318.1	($319.0)	($0.9)	($211.9)	$211.1	($0.8)	($1.7)
	Jun	$316.0	($344.9)	($28.9)	($215.9)	$232.6	$16.7	($12.2)
	Jul	$317.4	($306.8)	$10.6	($218.4)	$209.2	($9.2)	$1.4
	Aug	$380.9	($403.6)	($22.7)	($236.1)	$253.6	$17.5	($5.2)
	Sep	$369.1	($348.0)	$21.1	($191.6)	$180.8	($10.8)	$10.3
	Total	$2,594.6	($2,625.4)	($30.8)	($1,638.8)	$1,651.5	$12.6	($18.2)

Generation and Transmission Planning[1]

Overview

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[2]

- 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[3]

- 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.[4]
- 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

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2022) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," (Accessed on September 30, 2022) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
4 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

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.

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.[5]

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."[6] 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).[7]

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

5 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).

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

7 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).

changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[8] 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 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.[9]
- 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.

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.[10] (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.[11] (Priority: Medium. First reported 2013. Status: Partially adopted.)

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

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

10 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>.

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

- 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.[12] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. 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.)[13]
- 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.)[14]
- 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.)

12 Ibid.

13 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).

14 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).

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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.[15] (Priority: Medium. First reported 2015. Status: Not adopted.)

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

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.)

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. 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.[16]

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

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

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.

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.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[17] As of September 30, 2022, PJM had an 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, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 196,245.9 MW of PJM installed capacity, 33,367.1 MW (17.0 percent) are in the AEP Zone, of which 13,463.0 MW (40.3 percent) are coal fired steam units, 8,469.0 MW (25.4 percent) are combined cycle units and 2,071.0 MW (6.2 percent) are nuclear units.

Table 12-1 Existing capacity: September 30, 2022 (By zone and unit type (MW))[18]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	781.6	544.7	26.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	5.9	67.1	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,438.3
AEP	4.0	8,469.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	484.7	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	33,367.1
APS	80.4	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	29.6	0.0	18.3	134.3	0.0	0.0	5,299.0	0.0	0.0	0.0	985.1	0.0	10,744.9
ATSI	0.0	4,647.5	958.0	608.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	42.5	0.0	0.0	0.0	1,490.0	325.0	0.0	136.0	0.0	0.0	10,365.9
BGE	0.0	0.0	267.6	228.8	0.0	0.0	0.0	0.4	1,716.0	0.0	0.0	4.2	1.1	0.0	0.0	1,578.0	143.5	397.0	57.0	0.0	0.0	4,393.6
COMED	110.0	3,471.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	9.0	0.0	0.0	2,646.0	1,326.0	0.0	0.0	5,031.0	0.0	29,981.1
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	36.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	967.6
DUKE	18.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	200.0	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,810.0
DUQ	0.0	306.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,118.7
DOM	0.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	106.4	3,176.5	0.0	0.0	3,479.2	55.0	800.0	368.4	587.0	0.0	29,021.8
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	320.4	0.0	0.0	410.0	710.0	153.0	70.0	0.0	0.0	4,994.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,597.0
JCPLC	40.0	2,229.5	531.1	225.6	0.0	0.4	140.0	0.0	0.0	0.0	0.0	14.1	396.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,577.0
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	30.9	0.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,220.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	0.0	3.3	762.0	0.0	103.0	0.0	0.0	11,980.0
PE	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	17.8	13.5	0.0	0.0	6,053.5	610.0	0.0	42.0	1,100.4	0.0	10,912.0
PEPCO	0.0	1,736.5	764.2	308.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	2.5	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	4,036.0
PPL	20.0	5,558.5	286.6	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	35.0	0.0	0.0	2,547.9	2,449.0	0.0	29.0	216.5	0.0	14,457.4
PSEG	7.7	4,223.1	958.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,108.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	3,765.6
Total	308.5	54,253.2	24,421.3	3,763.9	43.8	32.0	4,792.0	2,771.5	33,452.6	176.1	218.5	327.6	5,109.7	0.0	0.0	44,332.7	8,367.6	1,350.0	1,096.5	11,428.4	0.0	196,245.9

17 The unit type RICE refers to Reciprocating Internal Combustion Engines.
18 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 196,245.9 MW of installed capacity, 48,193.9 MW (24.6 percent) are in Pennsylvania, of which 8,284.7 MW (18.0 percent) are coal fired steam units, 18,292.2 MW (38.0 percent) are combined cycle units and 8,843.8 MW (18.4 percent) are nuclear units.

Table 12-2 Existing capacity: September 30, 2022 (By state and unit type (MW))

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	0.0	0.0	410.0	710.0	0.0	70.0	0.0	0.0	2,412.4
IL	110.0	3,471.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	9.0	0.0	0.0	2,646.0	1,326.0	0.0	0.0	5,031.0	0.0	29,981.1
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	130.1	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,694.9
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,717.0	1,684.5	552.7	0.0	0.0	0.0	0.4	1,716.0	0.0	76.0	18.9	343.3	0.0	0.0	1,758.0	1,307.6	550.0	109.0	295.0	0.0	11,148.4
MI	0.0	2,194.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,289.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	1,006.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,712.5
NJ	47.7	7,234.2	2,034.0	251.6	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	29.0	693.6	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,123.6
OH	22.0	8,609.7	4,201.2	680.2	6.4	0.0	0.0	200.0	2,134.0	0.0	47.0	47.3	386.1	0.0	0.0	8,310.0	47.0	0.0	136.0	1,147.7	0.0	25,974.6
PA	49.9	18,292.2	1,526.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	176.1	40.5	82.6	116.5	0.0	0.0	8,684.7	4,181.0	0.0	234.0	1,582.3	0.0	48,193.9
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VA	0.0	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	112.4	2,400.0	0.0	0.0	2,474.2	515.0	800.0	368.4	12.0	0.0	27,574.1
WV	58.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	20.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,636.8
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	3,765.6
Total	308.5	54,253.2	24,421.3	3,763.9	43.8	32.0	4,792.0	2,771.5	33,452.6	176.1	218.5	327.6	5,109.7	0.0	0.0	44,332.7	8,367.6	1,350.0	1,096.5	11,428.4	0.0	196,245.9

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of September 30, 2022. 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.

Table 12-3 Capacity (MW) by unit type and age (years): September 30, 2022

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	308.5	43,889.2	5,136.3	0.0	43.8	32.0	0.0	294.0	0.0	164.1	20.0	242.5	5,109.7	0.0	0.0	3,475.0	82.0	0.0	47.4	11,404.4	0.0	70,248.8
20 to 40	0.0	10,173.0	18,780.7	960.0	0.0	0.0	3,003.0	430.4	14,992.0	12.0	25.0	85.1	0.0	0.0	0.0	6,215.4	73.0	0.0	843.1	24.0	0.0	55,616.7
40 to 60	0.0	191.0	504.3	2,803.9	0.0	0.0	1,789.0	340.0	18,460.6	0.0	173.5	0.0	0.0	0.0	0.0	31,940.5	6,451.1	1,350.0	0.0	0.0	0.0	64,003.9
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,707.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,701.8	1,761.5	0.0	206.0	0.0	0.0	6,376.4
Total	308.5	54,253.2	24,421.3	3,763.9	43.8	32.0	4,792.0	2,771.5	33,452.6	176.1	218.5	327.6	5,109.7	0.0	0.0	44,332.7	8,367.6	1,350.0	1,096.5	11,428.4	0.0	196,245.9

Figure 12-1 Capacity (MW) by age (years): September 30, 2022

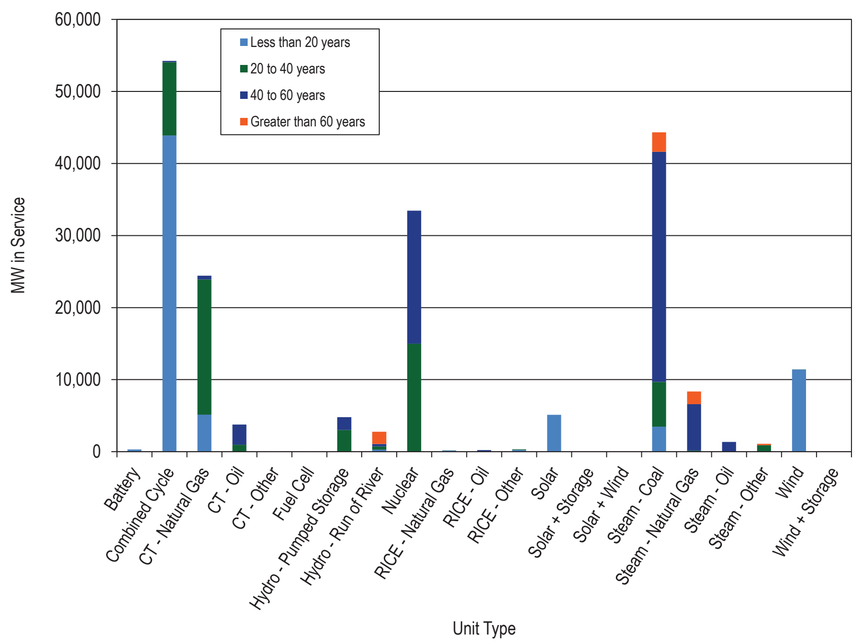


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and September 30, 2022. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through September 30, 2022

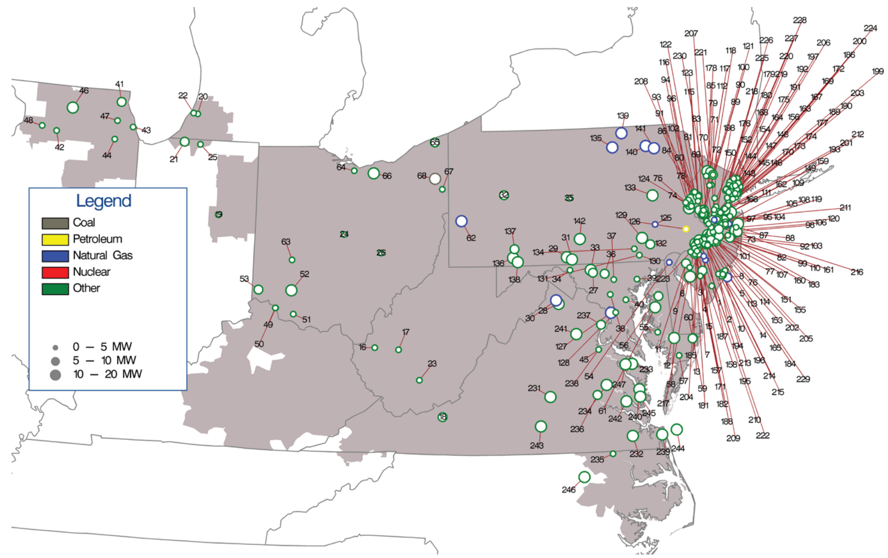


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through September 30, 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	DPL CHURCH HILL 1 SP	111	JC OLD BRIDGE 1 SP	166	PS EDISON 1 SP	221	PS SUNNYMEADE SOLAR 1 SP
2	ACE CATES ROAD 2 SP	57	DPL COSTEN 1 SP	112	JC PAUCH 3 SP	167	PS ESSEX 105 CT	222	PS TAYLORS LANE 1 SP
3	ACE CEDAR BRANCH 1 SP	58	DPL HEBRON 1 SP	113	JC PEMBERTON 1 SP	168	PS FAIRLAWN SOLAR 1 SP	223	PS THOROFARE SOLAR 2 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	DPL WORCESTER NORTH 1 SP	114	JC PEMBERTON 2 SP	169	PS FOODBANK 1 SP	224	PS TURNPIKE 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	DPL WORCESTER SOUTH 2 SP	115	JC QUAKERTOWN 9 SP	170	PS FORTY NINTH SOLAR 1 SP	225	PS W CALDWELL SOLAR 1 SP
6	ACE GEMS LANDFILL 1 SP	61	DPL WYE MILLS 1 SP	116	JC RICHLINE 3 SP	171	PS GLOUCESTER SOLAR 1 SP	226	PS W CALDWELL SOLAR 2 SP
7	ACE MAYS LANDING 1 SP	62	DUQ PIT MICROGRID 1 CT	117	JC RINGOES 1 SP	172	PS HACKENSACK 1 SP	227	PS WALDWICK SOLAR 1 SP
8	ACE MIDTOWN THERMAL 2 CT	63	FE DOVETAIL 1 CT	118	JC SUSSEX 1 LF	173	PS HIGHLAND PARK 3 BT	228	PS WEST ORANGE SOLAR 1 SP
9	ACE OAK FAIRTON 1 SP	64	FE ERIE COUNTY 1 LF	119	JC TINTON FALLS 3 SP	174	PS HIGHLAND PARK 4 SP	229	PS WEST PEMBERTON 1 SP
10	ACE PEAR STREET 1 SP	65	FE GENEVA 1 LF	120	JC UPPER FREEHOLD 1 SP	175	PS HILLSDALE SOLAR 1 SP	230	PS WEST WINDSOR 1 CT
11	ACE PILESGROVE 1 SP	66	FE LORAIN 1 LF	121	JC WANTAGE 2 SP	176	PS HINCHMANS SOLAR 1 SP	231	VP BUCKINGHAM 1 SP
12	ACE PILESGROVE 2 SP	67	FE MAHONING 1 LF	122	JC WARREN 1 SP	177	PS HOBOKEN SOLAR 2 SP	232	VP GARDNER FARMS 1 SP
13	ACE PITTSGROVE 1 SP	68	FE WARREN-EVERGREEN 1 CT	123	JC WASHBURN AVE 4 SP	178	PS HOPEWELL 1 SP	233	VP GARDYS MILL ROAD 5 SP
14	ACE SEASHORE 1 SP	69	JC AUGUSTA 1 SP	124	ME GLENDON 1 LF	179	PS HOPEWELL 2 BT	234	VP HOLLYFIELD 1 SP
15	ACE TANSBORO ROAD 1 FC	70	JC BEAVER RUN 3 SP	125	ME READING HOSPITAL 1 CT	180	PS JACKSON SOLAR 1 SP	235	VP MURPHY 1 SP
16	AEP BALLS GAP 1 BT	71	JC BERKSHIRE 2 SP	126	PE MORRIS ROAD 1 D	181	PS KINSLEY BEAVER 2 SP	236	VP NORTHEAST 2 LF
17	AEP CHARLESTON 1 LF	72	JC BERNARDS TOWNSHIP 1 SP	127	PEP CAPITAL POWER PLANT 1 CT	182	PS KINSLEY DEPTFORD 1 SP	237	VP OCCOQUAN 1 LF
18	AEP CLOYDS MT 1 LF	73	JC BRICKYARD 4 SP	128	PEP ROLLINS AVENUE 3 SP	183	PS KUSER SOLAR 1 SP	238	VP OCCOQUAN 2 LF
19	AEP DEERCREEK 1 SP	74	JC COPPER HILL 4 SP	129	PL DART CONTAINER 1-2 LF	184	PS LANDFILL 5 SP	239	VP OCEANA 1 SP
20	AEP EAST WATERVLIET 1 SP	75	JC CYPHERS ROAD 5 SP	130	PL HOLTWOOD 11	185	PS LAWNSIDE 14 BT	240	VP PULLER 1 SP
21	AEP OLIVE 1 SP	76	JC DIXSOLAR 51 SP	131	PL HOLTWOOD 13	186	PS LEONIA SOLAR 1 SP	241	VP REMINGTON 1 SP
22	AEP ORCHARD HILLS 1 LF	77	JC DIXSOLAR 52 SP	132	PL KEYSTONE 1 SP	187	PS LUMBERTON STACY HAINES 5 SP	242	VP ROCHAMBEAU 1 SP
23	AEP RALEIGH COUNTY 1 LF	78	JC DOMIN LANE 1 SP	133	PL PA SOLAR 1 SP	188	PS MANTUA CREEK 7 BT	243	VP TWITTYS CREEK 1 SP
24	AEP TRENT 1 BT	79	JC DURBAN AVENUE 1 SP	134	PL TURKEY HILL 1 WF	189	PS MARION SOLAR 1 SP	244	VP VIRGINIA OFFSHORE 1 WF
25	AEP TWINBRANCH 1 SP	80	JC E FLEMINGTON 5 SP	135	PN ALPACA GLORY BARN 1 D	190	PS MATRIX PA SOLAR 2 SP	245	VP WAN - GLOUCESTER 1 SP
26	AEP ZANESVILLE 2 LF	81	JC EAST AMWELL 7 SP	136	PN GARRETT 1 BT	191	PS MAYWOOD SOLAR 1 SP	246	VP WHITAKERS 1 SP
27	AP BAKER POINT 1 SP	82	JC EGYPT 3 SP	137	PN LAUREL HIGHLANDS 2 LF	192	PS METRO HQ 2 SP	247	VP WOODBINE ROAD 1 SP
28	AP DOUBLE TOLLGATE SP	83	JC FISCHER 8 SP	138	PN MEYERSDALE 2 BT	193	PS MIDDLESEX 1 SP		
29	AP ELK HILL 1 SP	84	JC FOUL RIFT ROAD 1 SP	139	PN MILAN ENERGY 1 D	194	PS MILL CREEK 1 SP		
30	AP HP HOOD 1 CT	85	JC FRANKFORD 4 SP	140	PN NORTH MESHOPPEN 1 CT	195	PS MOORESTOWN 1 SP		
31	AP LETZBURG - ELK HILL 2 SP	86	JC FRANKLIN 7 SP	141	PN OXBOW CREEK ENERGY CENTER 1 D	196	PS MT LAUREL 1 SP		
32	AP MAHONING CREEK 1 H	87	JC FREEMALL 1 FC	142	PN WHITETAIL 1 SP	197	PS NEW MILFORD SOLAR 1 SP		
33	AP MT ST MARYS PV PARK 2 SP	88	JC FRENCHES 2 SP	143	PS ALDENE SOLAR 1 SP	198	PS NEW ROAD 1 SP		
34	AP PINESBURG 1 SP	89	JC FRENCHTOWN 1 SP	144	PS ATHENIA SOLAR 1 SP	199	PS NEWARK SOLAR 1 SP		
35	AP STATE COLLEGE 1 BT	90	JC FRENCHTOWN 2 SP	145	PS BAYONNE 1 SP	200	PS NEWARK SOLAR 3 SP		
36	AP UNION BRIDGE 1 SP	91	JC FRENCHTOWN 3 SP	146	PS BAYONNE SOLAR 2 SP	201	PS NIXON LANE 2 SP		
37	BC ALPHA RIDGE 1 LF	92	JC HANOVER 2 SP	147	PS BELLEVILLE SOLAR 1 SP	202	PS NORTH AMERICAN 4 SP		
38	BC BRIGHTON DAM 1 H	93	JC HARMONY 1 SP	148	PS BENNETTS SOLAR 1 SP	203	PS NORTH AVE SOLAR 1 SP		
39	BC KINGSVILLE 1 SP	94	JC HIGH STREET 6 SP	149	PS BLACK ROCK 1 SP	204	PS OWENS CORNING 1 SP		
40	BC MILLERSVILLE 1 LF	95	JC HOFFMAN STATION ROAD 2 SP	150	PS BRIDGEWATER SOLAR 2 SP	205	PS PARKLANDS 1 SP		
41	COM COUNTRYSIDE 1 LF	96	JC HOLLAND 4 SP	151	PS BUSTLETON 2 SP	206	PS PATERSON PLANK ROAD 1 SP		
42	COM DIXON LEE 5 LF	97	JC HOLMDEL 9 SP	152	PS CALDWELL PUMP 2 BT	207	PS PENNINGTON 3 BT		
43	COM GRAND RIDGE 6 BT	98	JC HOWELL 1 SP	153	PS CAMPUS DRIVE 2 SP	208	PS PENNINGTON 4 SP		
44	COM MAGID GLOVE 1 BT	99	JC JACOBSTOWN 1 SP	154	PS CEDAR GROVE SOLAR 1 SP	209	PS PENNSAUKEN 1 LF		
45	COM MORRIS 1 LF	100	JC JUNCTION ROAD 6 SP	155	PS CEDAR LANE FLORENCE 6 SP	210	PS PENNSAUKEN 3 SP		
46	COM ORCHARD 1 LF	101	JC LAKEHURST 3 SP	156	PS COOK ROAD SOLAR 2 SP	211	PS PRINCETON HOSPITAL 1 CT		
47	COM SOLBERG 1 BT	102	JC LEBANON 1 SP	157	PS COOPER HOSPITAL 1 BT	212	PS RARITAN CENTER 3 SP		
48	COM STERLING RAIL 1 BT	103	JC LEGLER LANDFILL 7 SP	158	PS COOPER HOSPITAL 15 SP	213	PS REEVES EAST 3 SP		
49	DEOK BECKJORD 1 BT	104	JC MANALAPAN 1 SP	159	PS CRANBURY 2 SP	214	PS REEVES SOUTH 1 SP		
50	DEOK BECKJORD 2 BT	105	JC MILLHURST 3 SP	160	PS CROSSWIC 1 SP	215	PS REEVES WEST 4 SP		
51	DEOK BROWN COUNTY 1 LF	106	JC MUDDY FORGE 3 SP	161	PS CROSSWIC 2 SP	216	PS RIDER UNIVERSITY 3 SP		
52	DEOK CLINTON 1 BT	107	JC NORTH HANOVER 4 SP	162	PS DEVILSBROOK 1 SP	217	PS RIVER ROAD 2 SP		
53	DEOK WILLEY 1 BT	108	JC NORTH PARK 1 SP	163	PS DOREMUS SOLAR 1 SP	218	PS ROSELAND SOLAR 1 SP		
54	DPL BLOOM ENERGY 1 FC	109	JC NORTH PARK 2 SP	164	PS E RUTHERFORD SOLAR 1 SP	219	PS SADDLE BROOK SOLAR 1 SP		
55	DPL BUCKTOWN 1 SP	110	JC NORTH RUN 11 SP	165	PS EASTAMPTON 1 SP	220	PS SPRINGFIELD SOLAR 1 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and September 30, 2022. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through September 30, 2022

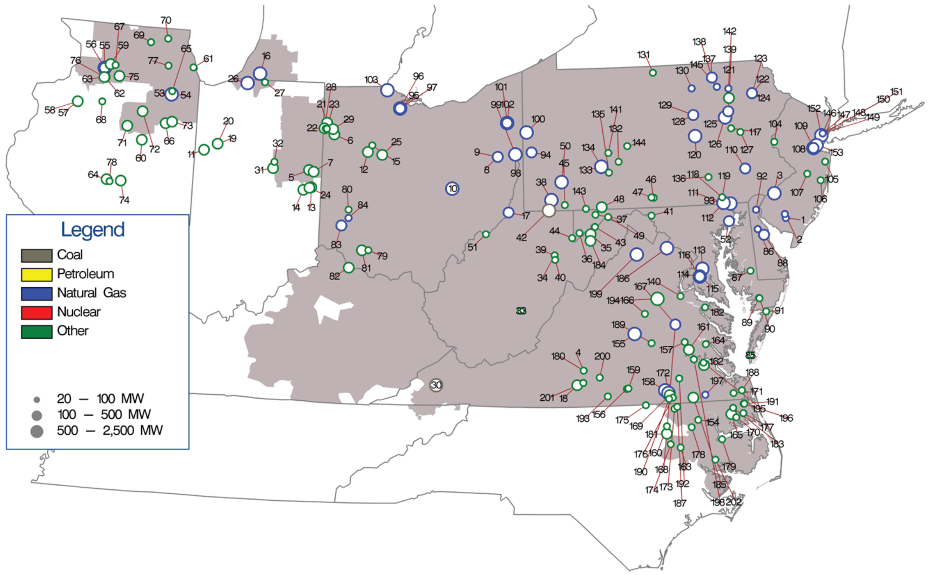


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through September 30, 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	COM 942 NELSON 2 CC	111	PE DELTA 1-4 CC	166	VP DESPER 1 SP
2	ACE VINELAND 11 CT	57	COM BISHOP HILL 1 WF	112	PE DELTA 5-7 CC	167	VP DOSWELL 2 CT
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	COM BISHOP HILL 2 WF	113	PEP KEYS ENERGY CENTER 1 CC	168	VP DOSWELL 3 CT
4	AEP ALTAVISTA 1 SP	59	COM BLOOMING GROVE 1 WF1	114	PEP ST CHARLES - KELSON RIDGE 1 CC	169	VP DRY BREAD 1 SP
5	AEP BITTER RIDGE 1 WF	60	COM BRIGHT STALK 1 WF	115	PEP ST CHARLES-KELSON RIDGE 1 CC	170	VP ELIZABETH CITY 1 SP
6	AEP BLUE CREEK 3 WF	61	COM GRAND RIDGE 7 BT	116	PEP ST CHARLES-KELSON RIDGE 2 CC	171	VP GRASSFIELD 1 SP
7	AEP BLUFF POINT 2 WF	62	COM GREEN RIVER 1 WF	117	PL HAZEL 1 FW	172	VP GREENSVILLE 1 CC
8	AEP CARROLL COUNTY 1 CC	63	COM GREEN RIVER 2 WF	118	PL HOLTWOOD 18	173	VP GUTENBERG - OCONECHE 1 SP
9	AEP CARROLL COUNTY 2 CC	64	COM HILLTOPPER 1 WF	119	PL HOLTWOOD 19	174	VP HARTS MILL 1 SP
10	AEP DRESDEN 1 CC	65	COM JOLIET 1 BT	120	PL HUMMEL STATION 1 CC	175	VP HAWTREE CREEK 1 SP
11	AEP FOWLER RIDGE 4 WF	66	COM KELLY CREEK 1 WF	121	PL HUNLOCK CC	176	VP IVORY LANE 1 SP
12	AEP HARDIN 2 SP	67	COM LEE DEKALB 3 BT	122	PL LACKAWANNA COUNTY 1 CC	177	VP IVY NECK 2 SP
13	AEP HEADWATERS 1 WF	68	COM LONE TREE 3 WF	123	PL LACKAWANNA COUNTY 2 CC	178	VP KELFORD 1 SP
14	AEP HEADWATERS 2 WF	69	COM MARENGO 1 BT	124	PL LACKAWANNA COUNTY 3 CC	179	VP MACKEYS 1 SP
15	AEP HOG CREEK 1 WF	70	COM MCHENRY 1 BT	125	PL MOXIE FREEDOM 11 CC	180	VP MECHANICSVILLE 2 SP
16	AEP INDECK NILES ENERGY CENTER 1 CC	71	COM MINONK 1 WF	126	PL MOXIE FREEDOM 21 CC	181	VP MOCCASIN CREEK - FERN 1 SP
17	AEP LONG RIDGE ENERGY 1 CC	72	COM OTTER CREEK 1 WF	127	PL PA SOLAR 2 SP	182	VP MONTROSS 1 SP
18	AEP MAPLEWOOD 1 SP	73	COM PILOT HILL 1 WF	128	PL PATRIOT 1 F	183	VP MORGAN CORNER 1 SP
19	AEP MEADOW LAKE 5 WF	74	COM RADFORDS RUN 1 WF	129	PL PATRIOT 2 F	184	VP NEW CREEK 1 WF
20	AEP MEADOW LAKE 6 WF	75	COM SHADY OAKS 1 WF	130	PN BEAVER DAM 1 D	185	VP NEWSOMS 1 SP
21	AEP PAULDING 3 WF	76	COM WALNUT RIDGE 1 WF	131	PN BIG LEVEL 1 WF	186	VP PANDA STONEWALL 1 CC
22	AEP PAULDING 41 WF	77	COM WEST CHICAGO 3 BT	132	PN CHESTNUT FLATS 1 WF	187	VP PECAN 1 SP
23	AEP PAULDING 42 WF	78	COM WHITNEY HILL 2 WF	133	PN FAIRVIEW 1 CC	188	VP POCATY 1 SP
24	AEP RIVERSTART 1 SP	79	DAY HIGHLAND COUNTY 1 SP	134	PN FAIRVIEW 2 CC	189	VP POWHATAN 2 SP
25	AEP SCIOTO RIDGE 1 WF	80	DAY TAIT 8 BT	135	PN HIGHLAND NORTH 2 WF	190	VP PUMPKINSEED 1 SP
26	AEP ST JOSEPH ENERGY CENTER 1 CC	81	DEOK HILLCREST 1 SP	136	PN LAUREL HILLS 1 WF	191	VP RANCHLAND 2 SP
27	AEP ST JOSEPH SOLAR PARK 1 SP	82	DEOK MELDAHL DAM 1 H	137	PN LIBERTY ASYLUM 10 F	192	VP SAPONY 1 SP
28	AEP TIMBER2 1 WF	83	DEOK MIDDLETOWN ENERGY 1 CC	138	PN LIBERTY ASYLUM 20 F	193	VP SOUTH BOSTON 1 F
29	AEP TRISHE 1 WF	84	DEOK YANKEE 1 F	139	PN MEHOOPANY 1 WF	194	VP SPOTSYLVANIA 1 SP
30	AEP VIRGINIA CITY 1 F	85	DPL CHERRYDALE 1 SP	140	PN MEHOOPANY 2 WF	195	VP SPRING GROVE 1 SP
31	AEP WILDCAT 1A WF	86	DPL DEMEC - CLAYTON 2 CT	141	PN PATTON 1 WF	196	VP SUMMIT FARMS 1 SP
32	AEP WILDCAT 1B WF	87	DPL DORCHESTER COUNTY 1 SP	142	PN PGCOGEN 2 CT	197	VP UNION CAMP 9-10 F
33	AP BEECH RIDGE 2 WF	88	DPL GARRISON EC 1 CC	143	PN RINGER HILL 1 WF	198	VP WARDS CREEK 1 SP
34	AP BEECH RIDGE 3 BT	89	DPL GREAT BAY KINGS CREEK 1 SP	144	PN SANDY RIDGE 1 WF	199	VP WARREN COUNTY FRONT ROYAL CC
35	AP BLACK ROCK 1 WF	90	DPL GREAT BAY KINGS CREEK 2 SP	145	PN SUGAR RUN 2 CT	200	VP WATER STRIDER 1 SP
36	AP FAIR WIND 2 WF	91	DPL OAK HALL 1 SP	146	PS KEARNY 131 CT	201	VP WHITEHORN 1 SP
37	AP FOURMILE RIDGE 1 WF	92	DPL RED LION 1 FC	147	PS KEARNY 132 CT	202	VP WILKINSON ENERGY CENTER 1 SP
38	AP GREENE COUNTY 1 CC	93	DPL WILDCAT POINT 1 CC	148	PS KEARNY 133 CT		
39	AP LAUREL MOUNTAIN 1 BT	94	DUQ MONACA-PENNCHEM 1 CC	149	PS KEARNY 134 CT		
40	AP LAUREL MOUNTAIN 1 WF	95	FE FREMONT 1 SCCT	150	PS KEARNY 141 CT		
41	AP MARLOWE 1 SP	96	FE FREMONT 2 SCCT	151	PS KEARNY 142 CT		
42	AP NORTH LONGVIEW 1 F	97	FE FREMONT ENERGY CENTER 3 CC	152	PS NEWARK ENERGY CENTER 10 CC		
43	AP PINNACLE 1 WF	98	FE HIBBETS MILLS ROAD 1 CC	153	PS SEWAREN 7 CC		
44	AP ROTH ROCK 1 WF	99	FE HIBBETS MILLS ROAD 2 CC	154	VP AULANDER HOLLOMAN 1 SP		
45	AP SOUTH CHESTNUT 1 WF	100	FE HICKORY RUN 1 CC	155	VP BEAR GARDEN		
46	AP ST THOMAS 1 SP	101	FE LORDSTOWN ENERGY CENTER 1 CC	156	VP BLUESTONE FARM 1 SP		
47	AP ST THOMAS 2 SP	102	FE LORDSTOWN ENERGY CENTER 2 CC	157	VP BRIEL FARM 1 SP		
48	AP TWIN RIDGES 1 WF	103	FE OREGON ENERGY CENTER 1 CC	158	VP BRUNSWICK 1CC		
49	AP WARRIOR RUN 2 BT	104	JC EDGE ROAD 5 BT	159	VP BUTCHER CREEK 1 SP		
50	AP WESTMORELAND 1 CC	105	JC HAMILTON ROAD 5 SP	160	VP CHESTNUT 1 SP		
51	AP WILLOW ISLAND 1 H	106	JC OAK RIDGE 3 SP	161	VP CHICKAHOMINY 1 SP		
52	BC PERRYMAN 6 CT	107	JC PLUMSTED ENERGY 6 BT	162	VP COLONIAL TRAIL WEST 1 SP		
53	COM 929 JACKSON 1 CC	108	JC WOODBRIDGE 1 CC	163	VP CONETOE 2 SP		
54	COM 929 JACKSON 2 CC	109	JC WOODBRIDGE 2 CC	164	VP CORRECTIONAL 1 SP		
55	COM 942 NELSON 1 CC	110	ME BIRDSBORO 1 CC	165	VP DESERT 1 WF		

Generation Retirements[19] [20]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[21] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[22]

Rules that preserve the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[23] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[24] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[25]

19 See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2022) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
20 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.
21 See OATT Part V and Attachment M–Appendix § IV.
22 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
23 See OATT § 230.3.3.
24 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
25 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2024

Table 12-6 shows that as of September 30, 2022, 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. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2024

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,166.5	1,016.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,113.8	97.0	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	40.0	240.5	99.0	284.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.8	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,069.6
Planned Retirements (October 1, 2022 and later)	0.0	0.0	132.6	76.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	17.7	0.0	0.0	0.0	4,184.0	1,326.0	0.0	0.0	0.0	0.0	5,770.3
Total	85.0	783.5	2,515.9	2,185.2	22.0	0.0	0.5	0.0	1,419.5	0.0	78.1	118.9	0.0	0.0	0.0	40,627.1	3,411.5	1,658.0	252.0	10.4	0.0	53,167.6

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2024, while Table 12-8 shows these retirements by state. Of the 53,167.6 MW of units that has been, or are planned to be, retired between 2011 and 2024, 40,627.1 MW (76.4 percent) are coal fired steam units. These coal fired steam units have an average age of 52.2 years and an average size of 217.3 MW. Over half of the retiring coal fired steam units, 53.9 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2024

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	6	14.2	6.2	85.0	0.2%
Combined Cycle	6	130.6	29.1	783.5	1.5%
Combustion Turbine	136	25.3	35.7	4,723.1	8.9%
Natural Gas	65	38.7	41.4	2,515.9	4.7%
Oil	65	33.6	46.5	2,185.2	4.1%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.7%
RICE	40	5.0	26.1	197.0	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	15	5.2	40.4	78.1	0.1%
Other	25	4.8	11.8	118.9	0.2%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	223	170.1	45.2	45,948.6	86.4%
Coal	187	217.3	52.2	40,627.1	76.4%
Natural Gas	22	155.1	59.1	3,411.5	6.4%
Oil	6	276.3	45.6	1,658.0	3.1%
Other	8	31.5	23.8	252.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	415	128.1	45.0	53,167.6	100.0%

Figure 12-4 is a map of unit retirements between 2011 and 2024, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2024

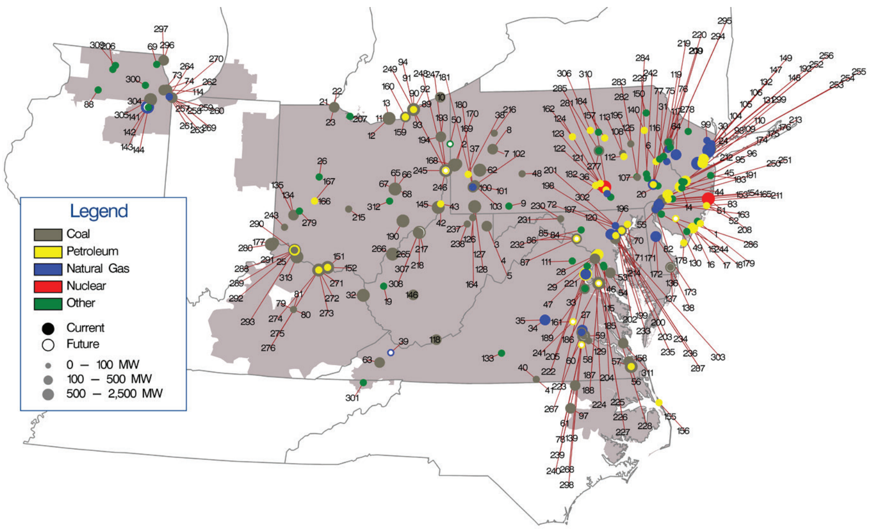


Table 12-8 Retirements (MW) by unit type and state: 2011 through 2024

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	800.0
IL	40.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	2,818.1	1,326.0	0.0	0.0	0.0	0.0	4,515.8
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	154.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	3,068.0	171.0	0.0	0.0	0.0	0.0	3,745.3
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	465.5	1,671.0	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	24.4	0.0	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	6,948.9
OH	42.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	26.7	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,015.4
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	13.9	20.5	0.0	0.0	0.0	5,299.3	283.0	176.0	109.0	10.4	0.0	7,211.8
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	8.4	0.0	0.0	0.0	3,897.9	563.0	786.0	83.0	0.0	0.0	5,788.9
WV	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,969.0	0.0	0.0	0.0	0.0	0.0	3,971.0
Total	85.0	783.5	2,515.9	2,185.2	22.0	0.0	0.5	0.0	1,419.5	0.0	78.1	118.9	0.0	0.0	0.0	40,627.1	3,411.5	1,658.0	252.0	10.4	0.0	53,167.6

Table 12-9 Unit identification for map of unit retirements: 2011 through 2024

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chesterfield 6	121	Harrisburg 4 CT	181	Mitchell 3	241	Rockville CT	301	West Kingsport LF
2	AES Beaver Valley	62	Cheswick 1	122	Harrisburg CT 1	182	Modern Power Landfill NUG	242	Rolling Hills Landfill Generator	302	West Shore CT 1-2
3	Albright 1	63	Clinch River 3	123	Harrisburg CT 2	183	Monmouth NUG landfill	243	SMART Paper	303	Westport 5
4	Albright 2	64	Columbia Dam Hydro	124	Harrisburg CT 3	184	Montour ATG	244	Salem County LF	304	Will County 3
5	Albright 3	65	Conesville 3	125	Harwood 1-2	185	Morgantown CT1	245	Sammis 1-4	305	Will County 4
6	Allentown CT 1-4	66	Conesville 4	126	Hatfield's Ferry 1	186	Morgantown CT2	246	Sammis Diesel Units	306	Williamsport-Lycoming CT 1-2
7	Armstrong 1	67	Conesville 5	127	Hatfield's Ferry 2	187	Morgantown Unit 1	247	Sammis Unit 5	307	Willow Island 1
8	Armstrong 2	68	Conesville 6	128	Hatfield's Ferry 3	188	Morgantown Unit 2	248	Sammis Unit 6	308	Willow Island 2
9	Arnold (Green Mtn. Wind Farm	69	Countryside Landfill	129	Hopewell James River Cogeneration	189	Morris Landfill Generator	249	Sammis Unit 7	309	Winnebago Landfill
10	Ashtabula 5	70	Crane 1	130	Howard Down 10	190	Muskingum River 1-5	250	Schuylkill 1	310	York Generation Facility
11	Avon Lake 10	71	Crane 2	131	Hudson 1	191	National Park 1	251	Schuylkill Diesel	311	Yorktown 1-2
12	Avon Lake 7	72	Crane GT1	132	Hudson 2	192	New Bay Cogen CC	252	Sewaren 1	312	Zanesville Landfill
13	Avon Lake 9	73	Crawford 7	133	Hurt NUG	193	Niles 1	253	Sewaren 2	313	Zimmer 1
14	BC Landfill	74	Crawford 8	134	Hutchings 1-3, 5-6	194	Niles 2	254	Sewaren 3		
15	BL England 1	75	Cromby 1	135	Hutchings 4	195	Northeastern Power NEPCO	255	Sewaren 4		
16	BL England 2	76	Cromby 2	136	Indian River 1	196	Notch Cliff GT1	256	Sewaren 6		
17	BL England 3	77	Cromby D	137	Indian River 3	197	Notch Cliff GT2	257	Southeast Chicago CT11		
18	BL England Diesel Units 1-4	78	DINWIDDIE 1 CT	138	Indian River 4	198	Notch Cliff GT3	258	Southeast Chicago CT12		
19	Balls Gap Battery Facility	79	Dale 1-2	139	Ingenco Petersburg	199	Notch Cliff GT4	259	Southeast Chicago CT5		
20	Barbados AES Battery	80	Dale 3	140	Jenkins CT 1-2	200	Notch Cliff GT5	260	Southeast Chicago CT6		
21	Bay Shore 2	81	Dale 4	141	Joliet 6	201	Notch Cliff GT6	261	Southeast Chicago CT7		
22	Bay Shore 3	82	Deepwater 1	142	Joliet 7	202	Notch Cliff GT7	262	Southeast Chicago CT8		
23	Bay Shore 4	83	Deepwater 6	143	Joliet 8	203	Notch Cliff GT8	263	Southeast Chicago GT10		
24	Bayonne Cogen Plant (CC)	84	Dickerson CT1	144	Joliet Energy Storage	204	Oaks Landfill	264	Southeast Chicago GT9		
25	Beckjord Battery Unit 2	85	Dickerson Unit 1	145	Kammer 1-3	205	Occoquan 1 LF	265	Sporn 1-4		
26	Bellefontaine Landfill Generating Station	86	Dickerson Unit 2	146	Kanawha River 1-2	206	Orchard Hills LF	266	Sporn 5		
27	Bellemeade	87	Dickerson Unit 3	147	Kearny 10	207	Ottawa County Project	267	Spruance NUG1 (Rich 1-2)		
28	Benning 15	88	Dixon Lee Landfill Generator	148	Kearny 11	208	Oyster Creek	268	Spruance NUG2 (Rich 3-4)		
29	Benning 16	89	Eastlake 1	149	Kearny 9	209	PL MARTINS CREEK 1-4 CT	269	State Line 3		
30	Bergen 3	90	Eastlake 2	150	Keystone Recovery (Units 1 - 7)	210	PL MARTINS CREEK 1-4 CT	270	State Line 4		
31	Bethlehem Renewable Energy Generator (Landfill)	91	Eastlake 3	151	Killen 2	211	Pedricktown Cogen CC	271	Stuart 1		
32	Big Sandy 2	92	Eastlake 4	152	Killen CT	212	Pennsbury Generator Landfill 1	272	Stuart 2		
33	Birchwood Plant	93	Eastlake 5	153	Kimberly Clark Generator	213	Pennsbury Generator Landfill 2	273	Stuart 3		
34	Bremo 3	94	Eastlake 6	154	Kinsley Landfill	214	Perryman 2	274	Stuart 4		
35	Bremo 4	95	Eddystone 1	155	Kitty Hawk GT 1	215	Picway 5	275	Stuart Diesels 1-4		
36	Brunner Island Diesels	96	Eddystone 2	156	Kitty Hawk GT 2	216	Piney Creek NUG	276	Stuart Diesels 1-4		
37	Brunot Island 1B	97	Edgecomb NUG (Rocky 1-2)	157	Koppers Co. IPP	217	Pleasant Unit 1	277	Sunbury 1-4		
38	Brunot Island 1C	98	Edison 1-3	158	Lake Kingman	218	Pleasant Unit2	278	Sussex County LF		
39	Buchanan 1-2	99	Elmwood Park Power	159	Lake Shore 18	219	Portland 1	279	Tait Battery		
40	Buggs Island 1 (Mecklenberg)	100	Elrama 1	160	Lake Shore EMD	220	Portland 2	280	Tanners Creek 1-4		
41	Buggs Island 2 (Mecklenberg)	101	Elrama 2	161	Lanier 1 CT	221	Possum Point 3	281	Three Mile Island Unit 1		
42	Burger 3	102	Elrama 3	162	Lock Haven CT 1	222	Possum Point 4	282	Titus 1		
43	Burger EMD	103	Elrama 4	163	Logan	223	Possum Point 5	283	Titus 2		
44	Burlington 8,11	104	Essex 10-11	164	MEA NUG (WVU)	224	Potomac River 1	284	Titus 3		
45	Burlington 9	105	Essex 12	165	MH50 Markus Hook Co-gen	225	Potomac River 2	285	Viking Energy NUG		
46	Buzzard Point East Banks 1,2,4-8	106	Essex 9	166	Mad River CTs A	226	Potomac River 3	286	Vineland West CT		
47	Buzzard Point West Banks 1-9	107	Evergreen Power United Corstack	167	Mad River CTs B	227	Potomac River 4	287	Wagner 2		
48	Cambria CoGen	108	FRACKVILLE WHEELABRATOR 1	168	Mansfield 1	228	Potomac River 5	288	Walter C Beckjord 1		
49	Cape May County Municipal LF	109	Fairless Hills Landfill A	169	Mansfield 2	229	Pottstown LF (Moser)	289	Walter C Beckjord 2		
50	Carbon Limestone LF	110	Fairless Hills Landfill B	170	Mansfield 3	230	R Paul Smith 3	290	Walter C Beckjord 3		
51	Cedar 1	111	Fauquier County Landfill	171	McKee 1	231	R Paul Smith 4	291	Walter C Beckjord 4		
52	Cedar 2	112	Fishbach CT 1	172	McKee 2	232	Reichs Ford Road Landfill Generator	292	Walter C Beckjord 5-6		
53	Chalk Point Unit 1	113	Fishbach CT 2	173	McKee 3	233	Riverside 4	293	Walter C Beckjord GT 1-4		
54	Chalk Point Unit 2	114	Fisk Street 19	174	Mercer 1	234	Riverside 6	294	Warren County Landfill		
55	Chambers CCLP	115	GUDE Landfill	175	Mercer 2	235	Riverside 7	295	Warren County NUG		
56	Chesapeake 1-4	116	Gilbert 1-4	176	Mercer 3	236	Riverside 8	296	Waukegan 7		
57	Chesapeake 7-10	117	Glen Gardner 1-8	177	Miami Fort 6	237	Riversville 5	297	Waukegan 8		
58	Chesterfield 3	118	Glen Lyn 5-6	178	Middle 1-3	238	Riversville 6	298	Weakley CT		
59	Chesterfield 4	119	Glendon LF	179	Missouri Ave B,C,D	239	Roanoke Valley 1	299	Werner 1-4		
60	Chesterfield 5	120	Gould Street Generation Station	180	Mitchell 2	240	Roanoke Valley 2	300	West Chicago Energy Storage		

Current Year Generation Retirements

Table 12-10 shows that 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.

Table 12-10 Unit deactivations: January through September, 2022

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Cape May County Municipal Utilities Authority	Cape May County Municipal LF	1.9	RICE-Other	ACEC	8	3/1/2022
GenOn Energy, Inc.	Avon Lake 10	21.0	CT-Oil	ATSI	54	3/31/2022
GenOn Energy, Inc.	Avon Lake 9	638.0	Steam-Coal	ATSI	52	3/31/2022
GenOn Energy, Inc.	Cheswick 1	565.0	Steam-Coal	DUQ	52	3/31/2022
Hoosier Energy Rural Electric Cooperative Inc	Orchard Hills LF	15.3	RICE-Other	COMED	5	3/31/2022
Riverstone Holdings LLC	Fishbach CT 1	28.0	CT-Oil	PPL	53	4/1/2022
Riverstone Holdings LLC	Fishbach CT 2	14.0	CT-Oil	PPL	53	4/1/2022
Riverstone Holdings LLC	Jenkins CT 1-2	27.6	CT-Oil	PPL	53	4/1/2022
Riverstone Holdings LLC	Lock Haven CT 1	14.0	CT-Oil	PPL	52	4/1/2022
Riverstone Holdings LLC	West Shore CT 1	28.0	CT-Oil	PPL	53	4/1/2022
Riverstone Holdings LLC	Williamsport-Lycoming CT 1-2	26.6	CT-Oil	PPL	55	4/1/2022
Renewable Energy Systems Holdings LTD	Joliet Energy Storage	20.0	Battery	COMED	7	4/29/2022
Renewable Energy Systems Holdings LTD	West Chicago Energy Storage	20.0	Battery	COMED	7	4/29/2022
American Electric Power Company, Inc.	Zimmer 1	330.0	Steam-Coal	DUKE	31	5/31/2022
American Municipal Power, Inc.	Ottawa County Project	3.6	RICE-Other	ATSI	21	5/31/2022
GenOn Energy, Inc.	Morgantown Unit 1	610.0	Steam-Coal	PEPCO	52	5/31/2022
GenOn Energy, Inc.	Morgantown Unit 2	619.0	Steam-Coal	PEPCO	51	5/31/2022
NRG Energy Inc	Waukegan 7	328.0	Steam-Coal	COMED	64	5/31/2022
NRG Energy Inc	Waukegan 8	356.1	Steam-Coal	COMED	60	5/31/2022
Riverstone Holdings LLC	Harwood 1-2	28.0	CT-Oil	PPL	55	5/31/2022
Starwood Capital Group LLC	Logan	219.0	Steam-Coal	ACEC	28	5/31/2022
The AES Corporation	Zimmer 1	365.0	Steam-Coal	DUKE	31	5/31/2022
Vistra Energy Corp	Zimmer 1	605.0	Steam-Coal	DUKE	31	5/31/2022
Arclight Capital Holdings LLC	Essex 9	81.0	CT-Natural Gas	PSEG	32	6/1/2022
Riverstone Holdings LLC	Allentown CT 1-4	56.0	CT-Oil	PPL	55	6/1/2022
Riverstone Holdings LLC	Harrisburg CT 1	13.4	CT-Oil	PPL	55	6/1/2022
Riverstone Holdings LLC	Harrisburg CT 2	13.9	CT-Oil	PPL	55	6/1/2022
Riverstone Holdings LLC	Harrisburg CT 3	13.8	CT-Oil	PPL	55	6/1/2022
Riverstone Holdings LLC	Martins Creek CT 3	18.0	CT-Natural Gas	PPL	51	6/1/2022
Riverstone Holdings LLC	New Bay Cogen CC	120.2	Combined Cycle	PSEG	29	6/1/2022
Riverstone Holdings LLC	Pedricktown Cogen CC	120.3	Combined Cycle	ACEC	30	6/1/2022
Starwood Capital Group LLC	Chambers CCLP	239.9	Steam-Coal	ACEC	28	6/7/2022
NRG Energy Inc	Will County 4	510.0	Steam-Coal	COMED	59	6/30/2022
Total		6,069.6				

Planned Generation Retirements

Table 12-11 shows that, as of September 30, 2022, there are 5,770.3 MW of generation that have requested retirement after September 30, 2022. Of the 5,770.3 MW requesting retirement, 4,184.0 MW (72.5 percent) are coal fired steam units. As of September 30, 2022, there are planned coal fired unit retirements in four different PJM zones. Of the 5,770.3 MW of planned retirements, 1,520.7 MW (24.6 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.

Table 12-11 Planned retirement of units: September 30, 2022

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
GenOn Energy, Inc.	Morgantown CT1	16.0	CT-Oil	PEPCO	01-Oct-22
GenOn Energy, Inc.	Morgantown CT2	16.0	CT-Oil	PEPCO	01-Oct-22
City of Vineland	Vineland West CT	26.0	CT-Oil	ACEC	10-Oct-22
GenOn Energy, Inc.	Dickerson CT1	18.0	CT-Oil	PEPCO	23-Oct-22
American Municipal Power, Inc.	Carbon Limestone LF	17.7	RICE-Other	ATSI	15-Nov-22
Dominion Energy, Inc.	Chesterfield 5	336.0	Steam-Coal	DOM	31-May-23
Dominion Energy, Inc.	Chesterfield 6	670.0	Steam-Coal	DOM	31-May-23
LS Power Equity Partners, L.P.	Buchanan 1-2	80.0	CT-Natural Gas	AEP	01-Jun-23
Castleton Commodities International LLC	DINWIDDIE 1 CT	3.0	RICE-Oil	DOM	01-Jun-23
NRG Energy Inc	Joliet 6	290.0	Steam-Natural Gas	COMED	01-Jun-23
NRG Energy Inc	Joliet 7	518.0	Steam-Natural Gas	COMED	01-Jun-23
NRG Energy Inc	Joliet 8	518.0	Steam-Natural Gas	COMED	01-Jun-23
Castleton Commodities International LLC	Lanier 1 CT	7.0	RICE-Oil	DOM	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 1	18.0	CT-Natural Gas	PPL	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 2	17.3	CT-Natural Gas	PPL	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 4	17.3	CT-Natural Gas	PPL	01-Jun-23
Avenue Capital Group LLC	Pleasant Unit 1	639.0	Steam-Coal	APS	01-Jun-23
Avenue Capital Group LLC	Pleasant Unit2	639.0	Steam-Coal	APS	01-Jun-23
Castleton Commodities International LLC	Rockville CT	4.0	RICE-Oil	DOM	01-Jun-23
Avenue Capital Group LLC	Sammis Diesel Units	13.0	RICE-Oil	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 5	290.0	Steam-Coal	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 6	600.0	Steam-Coal	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 7	600.0	Steam-Coal	ATSI	01-Jun-23
Castleton Commodities International LLC	Weakley CT	7.0	RICE-Oil	DOM	01-Jun-23
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	31-Dec-26
Total		5,770.3			

In addition to the 5,770.3 MW of announced unit retirements as of September 30, 2022, there are significantly more unit retirements expected as a result of state environmental actions. PJM anticipates an additional 20,000 MW of unit retirements between 2024 and 2030, and an additional 10,000 MW of unit retirements between 2031 and 2045.[26] [27]

26 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at February 23, 2022 meeting of the Planning Committee Special Session on CIR's for ELCC Resources at p8. <https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220223-special/20220223-item-04-generator-deliverability-proposal-analytical-results.ashx>.

27 See "Illinois Generation Retirement Study," (August 3, 2022). <http://www.pjm.com/-/media/library/reports-notices/special-reports/2022/2022-pjm-illinois-generation-retirement-study.ashx>.

Generation Queue[28]

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[29] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Queues A and B were open for one year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AH2 opened on October 1, 2021 and closed on March 10, 2022 and Queue AI1 opened on April 1, 2022. On June 24, 2021, PJM requested tariff modifications to close queue windows on September 10 and March 10, rather than September 30 and March 31.[30] This change allows more time to review the new requests to the queue without shortening the amount of time available for the resulting model builds and analyses. On August 23, 2021, the Commission approved the tariff modifications.[31]

Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. If a project is missing information, or if the submitting developer owes money from a prior queue request, the submission is defined to be deficient. PJM was required to perform the review and provide notification within five business days of receipt of the request. The developer had ten business days to respond. PJM had five business days to review the response. As a result of the large number of project submissions submitted close to the end of each queue window, PJM could not meet the required timeline. On June 24, 2021, PJM filed tariff changes to modify the deficiency review timeline.[32] PJM requested an increase in the initial notification to the interconnection customer from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. The developer has ten business days to respond. PJM requested an increase in PJM's time to respond from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. On August 23, 2021, the Commission approved the tariff modifications.[33] A queue position is assigned once the project has met the submission requirements. Projects that do not meet submission requirements are removed from the queue.

All projects that have entered a queue and have met the submission requirements have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in service. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[34] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.[35]

PJM has generally met the deadlines for feasibility and system impact studies. The increase in the number of projects submitted have contributed to a significant backlog in performing timely facility studies. The facility study includes the conceptual design, stability analyses and determines the network upgrades, and the costs associated with those upgrades. Modifications to proposed facilities and restudies resulting from the withdrawal of projects

28 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
29 See OATT Parts IV & VI.
30 See PJM Filing, Docket ER21-2203 (June 24, 2021).
31 176 FERC ¶ 61,117 (2021).
32 See PJM Filing, Docket ER21-2203 (June 24, 2021).
33 176 FERC ¶ 61,117 (2021).
34 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 14 (January 27, 2021).
35 PJM does not track the duration of suspensions or PJM termination of projects.

from the queue also affect the time to complete a facility study. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. The PJM queue evaluation process should also evaluate and address the incentives to project developers to act in ways that are not consistent with an effective and efficient queue process for the system. For example, 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 by requiring multiple restudies.

Starting in 2020, PJM has made significant progress in addressing many of the underlying issues. In 2020, PJM conducted interconnection process workshops designed to review current processes, receive input and recommendations from stakeholders and to develop improvements to the process, resulting in the creation of the Interconnection Process Reform Task Force (IPRTF) to improve overall queue management.

The proposal endorsed by the IPRTF includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[36] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The proposal also includes defining progress to completion through three phases, with a customer decision at the end of each. The proposed solution requires a stronger definition of site control, and includes readiness deposits (some of which are nonrefundable) based on the phase of development. Additional process modifications include limits to technology changes, improvements to the application review phase, removal of optional interconnection study processes, modifications to the study schedules to reduce the number of restudies required in the event of project modifications, adjusting the queue window schedule to coincide with the previous clusters' milestones, and modifications to cost responsibility by assigning responsibility to all projects within a queue cycle. 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.[37]

The proposal creates a transition process which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the existing queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 and transition cycle 2 and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. Transition cycle 1 is expected to begin in late 2023. Transition cycle 2 is expected to begin in late 2024. Projects submitted in queue window AH2 and beyond will be evaluated starting in early 2026. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown period. The transition process itself will not begin until projects eligible for the existing queue process have an executed ISA or the equivalent. After the process for projects in transition cycles 1 and 2 has been completed, projects in queue AH2 and possible subsequent queues will be studied. The new process will not be fully implemented until PJM provides notice that it is accepting applications for the first cycle entirely under the new process. That notice will be provided only after PJM has complete all the prior required transition steps.

On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR).[38] The purpose of the ANOPR is to review transmission related regulations and determine whether additional reforms to the regional transmission planning, cost allocation and generator interconnection processes are needed. The ANOPR discusses the impacts of transmission rules on the competitiveness of the energy markets but does not focus on the competitiveness of transmission itself. Given that the cost of transmission is increasing as a share of total wholesale power costs and now exceeds the cost of capacity in PJM, the cost effectiveness and competitiveness of the transmission planning and procurement process should be addressed when considering reforms.

36 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

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

38 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (July 15, 2021).

On June 16, 2022, the Commission issued a Notice of Proposed Rulemaking (NOPR).[39] The NOPR largely aligned with the PJM proposal that was endorsed by the IPRTF. The NOPR addresses reforms to implement a first ready/first served cluster study process, including cluster study costs and an allocation of network upgrade costs to the cluster, increased financial commitments and readiness requirements and improvements to the speed of the queue processing.

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.[40]

Interconnection Process Studies and Agreements[41]

In the study stage of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 is an overview of the studies PJM perform in the study stage of the interconnection process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

In addition to the feasibility, system impact and facilities studies, PJM may also perform additional studies under certain circumstances. These studies include the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM may perform.

Table 12-12 Interconnection planning process: study stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects in the queue.

39 See *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (June 16, 2022).

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

41 See "PJM Manual 14A: New Services Request Process," Rev. 29 (August 24, 2021) for a complete explanation of the interconnection process studies and agreements.

Table 12-13 Interconnection planning process: study stage – additional studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project will enter the construction stage of the interconnection process. The final agreements required depend on the type of project. These agreements include a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection process.

Table 12-14 Interconnection planning process: construction stage agreements

Agreement	Purpose
Interconnection Service Agreement (ISA)	An ISA defines the generation or transmission developer's cost responsibility for required system upgrades. For generation interconnection customers, the ISA defines the capacity interconnection rights for a capacity resource and any operational restrictions or other limitations. For transmission interconnection customers, the ISA defines transmission injection and withdrawal rights and applicable incremental delivery, available transfer capability revenue and auction revenue rights.
Interim Interconnection Service Agreements (I-ISA)	If a developer wishes to start project construction activities prior to completion of the generation or transmission interconnection facilities study, the interim ISA would commit the developer to pay all costs incurred for the construction activities being advanced.
Interconnection Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets and from state subsidies and incentives. On September 30, 2022, 277,040.0 MW were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[42]

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 window closed and the AI1 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 December 31, 2021. Table 12-15 shows MW in queues by expected

42 See "*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>.

completion year and MW changes in the queue between December 31, 2021, and September 30, 2022, for ongoing projects, i.e. projects with the status active, under construction or suspended.[43]

Table 12-15 Queue comparison by expected completion year (MW): December 31, 2021 and September 30, 2022[44]

			Year Change	
Year	As of 12/31/2021	As of 9/30/2022	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	0.0	0.0	0.0	0.0%
2013	0.0	0.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	3.4	3.4	0.0	0.0%
2017	395.0	135.0	(260.0)	(65.8%)
2018	668.6	407.8	(260.8)	(39.0%)
2019	4,470.6	1,220.9	(3,249.7)	(72.7%)
2020	6,417.1	5,198.1	(1,219.1)	(19.0%)
2021	22,270.3	19,900.7	(2,369.7)	(10.6%)
2022	40,243.9	38,457.6	(1,786.3)	(4.4%)
2023	54,779.4	56,270.4	1,491.0	2.7%
2024	57,504.2	64,183.0	6,678.8	11.6%
2025	35,470.5	45,932.2	10,461.7	29.5%
2026	8,636.2	21,828.5	13,192.3	152.8%
2027	5,840.1	11,883.6	6,043.5	103.5%
2028	2,508.0	4,700.8	2,192.8	87.4%
2029	2,460.1	5,028.1	2,568.0	104.4%
2030	0.0	290.0	290.0	0.0%
2031	0.0	1,600.0	1,600.0	0.0%
Total	241,667.4	277,040.0	35,372.7	14.6%

Table 12-16 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2021, and September 30, 2022. For example, 42,637.0 MW entered the queue in the first nine months of 2022. Of those 42,637.0 MW, 7,264.4 MW have been withdrawn. Of the total 236,657.8 MW marked as active on December 31, 2021, 6,249.1 MW were withdrawn, 3,895.8 MW were suspended, 2,546.0 MW started construction, and 137.5 MW went into service by September 30, 2022. Analysis of projects that were suspended on December 31, 2021 show that 3,369.3 MW came out of suspension and are now active as of September 30, 2022.

Table 12-16 Change in project status (MW): December 31, 2021 to September 30, 2022

		Status at 9/30/2022				
Status at 12/31/2021	Total at 12/31/2021	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2022)	0.0	35,372.7	0.0	0.0	0.0	7,264.4
Active	236,657.8	223,829.5	137.5	2,546.0	3,895.8	6,249.1
In Service	74,400.5	0.0	74,400.5	0.0	0.0	0.0
Under Construction	8,996.6	0.0	3,934.1	5,062.5	0.0	0.0
Suspended	9,120.9	3,369.3	0.0	5.0	2,959.3	2,787.3
Withdrawn	423,396.9	0.0	0.0	0.0	0.0	423,396.9
Total	752,572.6	262,571.4	78,472.1	7,613.5	6,855.1	439,697.6

On September 30, 2022, 277,040.0 MW were in generation request queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 262,571.4 MW in the status of Active on September 30, 2022, 6,689.7 MW (2.5 percent) were combined cycle projects. Of the 7,613.5 MW in the status of under construction, 3,272.7 MW (43.0 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 262,571.4 MW in the status of Active on September 30, 2022, 37,484.2 MW (14.3 percent) were renewable hybrid projects. Of the 7,613.5 MW in the status of under construction, 5.7 MW (0.08 percent) were renewable hybrid projects.

43 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
44 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-17 Current project status (MW) by unit type: September 30, 2022

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	49,433.0	6,689.7	3,253.8	4.0	396.6	5.0	730.0	112.8	154.2	14.4	0.0	0.0	121,595.0	37,275.2	209.0	29.0	6.0	0.0	20.0	42,643.8	0.0	262,571.4
Suspended	29.0	2,765.0	1,368.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,482.4	104.4	0.0	0.0	0.0	0.0	0.0	0.0	106.3	6,855.1
Under Construction	34.0	3,272.7	457.0	9.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	3,547.0	5.7	0.0	36.0	5.0	0.0	0.0	200.0	0.0	7,613.5
Total	49,496.0	12,727.4	5,078.8	13.0	396.6	8.0	730.0	112.8	198.2	14.4	0.0	0.0	127,624.5	37,385.3	209.0	65.0	11.0	0.0	20.0	42,843.8	106.3	277,040.0

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable, hybrid and other intermittent resources enter the queue and coal fired steam units retire. As of September 30, 2022, of the 277,040.0 MW in the generation request queues in the status of active, suspended or under construction, 127,624.5 MW (46.1 percent) were solar projects, 42,843.8 MW (15.5 percent) were wind projects, 17,831.6 MW (6.4 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 37,700.6 MW (13.6 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 65.0 MW (0.02 percent) were coal fired steam projects.

As of September 30, 2022, there are 4,184.0 MW of coal fired steam units and 1,458.6 MW of natural gas units slated for deactivation between October 1, 2022, and December 31, 2024 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The small but growing level of renewables, hybrids and other intermittents will also have increasingly significant impacts on the energy and capacity markets.

Table 12-18 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total MW that had been included in each queue. All items in queues A-V2 are either in service or have been withdrawn. As of September 30, 2022, there are 277,040.0 MW in queues that are not yet in service or withdrawn, of which 2.5 percent are suspended, 2.7 percent are under construction and 94.8 percent have not begun construction.

Table 12-18 Queue totals by status (MW): September 30, 2022[45]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	7,564.0	0.0	0.0	15,727.0	23,291.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,408.8	18,701.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	2,458.3	2,989.3
D Expired 31-Jan-00	0.0	825.6	0.0	0.0	7,349.0	8,174.6
E Expired 31-Jul-00	0.0	735.2	0.0	0.0	7,061.8	7,797.0
F Expired 31-Jan-01	0.0	36.0	0.0	0.0	3,092.5	3,128.5
G Expired 31-Jul-01	0.0	1,171.6	0.0	0.0	17,961.8	19,133.4
H Expired 31-Jan-02	0.0	699.0	0.0	0.0	8,421.9	9,120.9
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,237.4	3,340.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,028.7	4,285.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,148.8	0.0	0.0	8,129.3	10,278.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,192.7	0.0	0.0	5,200.5	8,393.2
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	9,745.7	12,893.6
R Expired 31-Jan-07	0.0	1,872.5	0.0	0.0	20,015.9	21,888.4
S Expired 31-Jul-07	0.0	3,543.5	0.0	0.0	12,396.5	15,940.0
T Expired 31-Jan-08	0.0	4,087.3	0.0	0.0	23,313.3	27,400.6
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	777.5	0.0	0.0	16,218.6	16,996.1
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	0.0	3,625.1	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	508.7	0.0	0.0	8,695.9	9,204.6
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
X1 Expired 30-Apr-11	0.0	1,103.8	0.0	0.0	6,200.6	7,304.4
X2 Expired 31-Jul-11	0.0	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	109.2	0.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	0.0	6,279.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,657.2	0.0	0.0	9,636.5	11,293.7
Y3 Expired 30-Apr-13	0.0	1,630.5	0.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	300.3	3,094.5	0.0	675.0	4,055.0	8,124.8
Z2 Expired 30-Apr-14	10.0	3,063.0	0.0	0.0	3,027.8	6,100.8
AA1 Expired 31-Oct-14	90.2	4,678.9	340.0	463.0	6,498.4	12,070.5
AA2 Expired 30-Apr-15	1,569.0	2,819.6	205.0	0.0	11,472.7	16,066.3
AB1 Expired 31-Oct-15	1,226.8	1,439.1	1,387.6	2,741.0	13,649.3	20,443.7
AB2 Expired 31-Mar-16	420.9	1,972.5	1,530.1	653.9	10,588.4	15,165.8
AC1 Expired 30-Sep-16	1,984.3	2,744.4	2,528.0	538.2	12,256.1	20,050.9
AC2 Expired 30-Apr-17	2,351.1	595.9	305.1	201.7	9,147.8	12,601.6
AD1 Expired 30-Sep-17	4,336.7	333.9	155.8	447.5	6,028.7	11,302.6
AD2 Expired 31-Mar-18	4,919.9	503.7	769.6	125.5	14,044.9	20,363.6
AE1 Expired 30-Sep-18	13,939.5	101.4	89.4	330.4	19,436.1	33,896.9
AE2 Expired 31-Mar-19	20,659.0	73.5	140.9	458.4	12,495.8	33,827.5
AF1 Expired 30-Sep-19	19,824.4	22.8	76.0	117.9	8,891.9	28,932.9
AF2 Expired 31-Mar-20	20,746.9	13.0	44.9	72.7	7,338.1	28,215.5
AG1 Expired 30-Sep-20	32,184.3	0.5	25.0	30.0	5,872.5	38,112.3
AG2 Expired 31-Mar-21	55,347.0	0.0	0.0	0.0	1,402.3	56,749.3
AH1 Expired 10-Sep-21	45,739.9	0.0	0.0	0.0	4,198.7	49,938.6
AH2 Expired 10-Mar-22	27,598.3	0.0	0.0	0.0	6,706.5	34,304.7
AI1 Opened 01-Apr-22	9,323.0	0.0	0.0	0.0	639.8	9,962.8
Total	262,571.4	78,472.1	7,613.5	6,855.1	439,697.6	795,209.6

45 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-19 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of September 30, 2022, 277,040.0 MW were in generation request queues for construction through 2029. Table 12-19 also shows the planned retirements for each zone.

Table 12-19 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2022[46]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	1,739.5	0.0	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	668.3	221.0	0.0	0.0	0.0	0.0	0.0	3,441.6	0.0	6,300.4	26.0
	DPL	1,064.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,401.7	270.0	0.0	0.0	0.0	0.0	0.0	7,369.5	0.0	11,556.1	410.0
	JCPLC	806.8	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	466.1	235.0	0.0	0.0	0.0	0.0	0.0	10,372.5	0.0	11,910.4	0.0
	PECO	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	145.4	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	199.4	0.0
	PSEG	1,782.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.2	22.6	0.0	0.0	5.0	0.0	0.0	1,300.0	0.0	3,894.9	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	5,392.3	507.1	905.0	0.0	0.0	0.0	30.0	0.0	44.0	0.0	0.0	0.0	3,740.6	753.6	0.0	0.0	5.0	0.0	0.0	22,483.6	0.0	33,861.1	436.0
SWMAAC	BGE	1,198.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0	0.0	154.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,407.6	0.0
	PEPCO	796.0	45.0	55.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	240.1	1,452.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	2,598.4	50.0
	SWMAAC Total	1,994.5	45.0	55.3	4.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0	0.0	395.1	1,452.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	4,006.1	50.0
WMAAC	MEC	955.2	75.0	11.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	861.4	162.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,072.7	0.0
	PE	997.8	85.0	585.5	0.0	3.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	6,291.0	1,411.8	0.0	0.0	0.0	0.0	0.0	503.7	0.0	9,881.5	0.0
	PPL	495.0	106.6	0.0	0.0	0.0	0.0	700.0	0.0	100.0	0.0	0.0	0.0	2,568.7	741.0	0.0	0.0	0.0	0.0	0.0	174.8	90.0	4,976.1	52.6
	WMAAC Total	2,448.0	266.6	597.0	7.5	3.6	3.0	700.0	0.0	100.0	0.0	0.0	0.0	9,721.1	2,314.9	0.0	0.0	0.0	0.0	0.0	678.5	90.0	16,930.3	52.6
Non-MAAC	AEP	10,985.9	3,360.0	842.1	0.0	379.2	0.0	0.0	51.0	0.0	0.0	0.0	0.0	43,642.8	15,638.8	0.0	65.0	0.0	0.0	0.0	3,523.0	0.0	78,487.7	80.0
	APS	2,944.8	4,660.0	30.0	0.0	0.0	0.0	0.0	15.0	0.0	14.4	0.0	0.0	6,549.1	2,548.3	0.0	0.0	0.0	0.0	0.0	959.1	16.3	17,737.0	1,278.0
	ATSI	2,218.0	1,953.0	523.7	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,069.2	891.6	0.0	0.0	0.0	0.0	0.0	297.7	0.0	12,954.7	1,520.7
	COMED	7,376.1	1,836.7	964.2	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	13,666.7	2,531.5	199.0	0.0	0.0	0.0	0.0	9,483.2	0.0	36,062.4	1,326.0
	DAY	340.0	0.0	20.0	0.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,558.4	500.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,433.1	0.0
	DUKE	277.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.9	40.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	1,006.1	0.0
	DLCO	205.0	0.0	3.5	0.0	0.0	0.0	0.0	46.8	0.0	0.0	0.0	0.0	88.9	107.5	0.0	0.0	0.0	0.0	20.0	0.0	0.0	471.7	0.0
	DOM	15,138.2	99.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31,927.7	7,333.8	0.0	0.0	0.0	0.0	0.0	5,418.8	0.0	61,055.5	1,027.0
	EKPC	176.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,156.0	3,094.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,426.1	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	608.5	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	39,661.2	11,908.7	3,521.5	1.5	393.0	5.0	0.0	112.8	0.0	14.4	0.0	0.0	113,767.7	32,864.8	209.0	65.0	0.0	0.0	20.0	19,681.7	16.3	222,242.6	5,231.7
	Total	49,496.0	12,727.4	5,078.8	13.0	396.6	8.0	730.0	112.8	198.2	14.4	0.0	0.0	127,624.5	37,385.3	209.0	65.0	11.0	0.0	20.0	42,843.8	106.3	277,040.0	5,770.3

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion.[47] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources will be determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. The 2023/2024 ELCC class rating for wind resources is 15.0 percent, for solar resources with tracking panels is 54.0 percent and for solar resources with fixed panels is 38.0 percent.[48] The ELCC class rating for battery or energy storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for an energy storage resource. PJM defined four different energy storage classes differentiated by duration. The ELCC class rating is 83.0 percent for storage resources that can continuously generate

46 This data includes only projects with a status of active, under construction, or suspended.

47 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

48 *ELCC Class Ratings for 2023-2024 BRA*, PJM Interconnection L.L.C. (December 16, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>

energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 98.0 percent for six hour storage and 100 percent for 8 hour storage and 10 hour storage.[49] Using the ELCC derate factors, based on the derating of 42,843.8 MW of wind resources to 6,426.6 MW, 127,624.5 MW of solar resources to 68,917.2 MW, 37,385.3 MW of solar + storage resources to 20,188.1 MW, 209.0 MW of solar + wind resources to 112.9 MW, 106.3 MW of wind + storage resources to 15.9 MW and 49,496.0 MW of battery resources to 41,081.7 MW, the 277,040.0 MW currently under construction, suspended or active in the queue would be reduced to 156,117.5 MW.[50]

Withdrawn Projects

The queue contains a substantial number of projects that are not likely to be built. The queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage, but the actual calculation of commercial probability factors is less than transparent.[51] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-20 and Table 12-21.

Table 12-20 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 3,425 projects withdrawn as of September 30, 2022, 1,722 (50.2 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,425 projects withdrawn, 644 (18.8 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-20 Last milestone at time of withdrawal: January 1, 1997 through September 30, 2022

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	690	20.1%	314	1,193
Feasibility Study	1,032	30.1%	268	1,633
System Impact Study	750	21.9%	719	3,248
Facilities Study	309	9.0%	1,136	4,107
Construction Service Agreement (CSA) or beyond	644	18.8%	1,385	7,864
Total	3,425	100.0%		

Average Time in Queue

Table 12-21 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,111 days, or 3.0 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 634 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-21 Project queue times by status (days): September 30, 2022[52]

Status	Average (Days)	Standard Deviation	Maximum
Active	739	471	3,356
In-Service	1,111	796	5,306
Suspended	1,587	627	3,256
Under Construction	1,808	682	4,872
Withdrawn	634	747	7,864

Table 12-22 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 3,104 projects in the queue as of September 30, 2022, 182 (5.9 percent) had a completed feasibility study and 474 (15.3 percent) had a completed construction service agreement.

49 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C. (August 1, 2021).

50 The ELCC derate adjusted MW are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.

51 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

52 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-22 Project queue times by milestone (days): September 30, 2022

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	1,618	52.1%	988	1,339
Feasibility Study	182	5.9%	782	1,190
System Impact Study	784	25.3%	1,058	2,304
Facilities Study	46	1.5%	1,490	2,160
Construction Service Agreement (CSA) or beyond	474	15.3%	1,589	4,872
Total	3,104	100.0%		

Table 12-23 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the queue in 2015, there was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018, but the time increased to 600 days for battery projects entering the queue in 2019.

Table 12-23 Average time in queue (days) by fuel type and year submitted (In Service Projects): September 30, 2022[53]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Battery	983	609	417	692	789	1,082	941	383	293	600	544		
CC	1,310	1,551	1,663	1,419	1,175	1,125	1,017	908	309	512			
CT - Natural Gas	1,131	804	953	1,073	734	619	1,404	932	805	395	319		
CT - Oil	717		259							280			
CT - Other	729	634	954	1,248	718	360							
Fuel Cell						827	643						
Hydro - Pumped Storage						1,402							
Hydro - Run of River			1,325	614	332		580	426	606				
Nuclear	885	866		1,234									
RICE - Natural Gas			1,702	1,053	1,332	798		250					
RICE - Oil						1,849							
RICE - Other	638	1,385	1,479	241	627	622	491		466				
Solar	1,701	1,395	969	1,014	1,003	1,534	1,336	1,084	892	444	413		
Solar + Storage									553				
Solar + Wind													
Steam - Coal	745		513	1,010	583	853	684	647	1,122				
Steam - Natural Gas				1,182		421	751						
Steam - Oil													
Steam - Other	256	838	643										
WInd	2,748	2,711	1,750	1,589	1,205	1,463	1,443	1,200	934				
Wind + Storage													

53 A blank cell in this table means that no project of that fuel type, which was submitted to the queue in that year, subsequently went in service.

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-24 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[54] For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the queue and complete the system impact study stage, 11.3 percent of the queued MW have gone into service. The completion rate for battery projects increases to 31.1 percent when battery projects complete the facility study agreement and further increases to 39.4 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.5 percent of the queued MW have gone into service.

54 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning."

Table 12-24 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: September 30, 2022

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	11.3%	31.1%	39.4%	0.5%
CC	33.5%	50.2%	73.0%	15.4%
CT - Natural Gas	61.5%	76.2%	80.1%	39.6%
CT - Oil	26.1%	48.8%	86.5%	18.1%
CT - Other	12.3%	18.6%	29.8%	8.4%
Fuel Cell	30.6%	31.6%	31.6%	30.2%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.1%
Hydro - Run of River	43.7%	60.0%	67.2%	21.1%
Nuclear	41.6%	51.6%	66.3%	32.6%
RICE - Natural Gas	30.7%	42.8%	47.4%	25.9%
RICE - Oil	34.0%	59.7%	59.7%	25.8%
RICE - Other	88.9%	91.3%	92.0%	77.9%
Solar	18.5%	43.2%	52.9%	2.7%
Solar + Storage	0.0%	2.3%	2.3%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.7%	25.5%	37.6%	6.3%
Steam - Natural Gas	91.1%	91.1%	91.1%	90.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.1%
Wind	0.2%	100.0%	100.0%	0.0%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On September 30, 2022, 277,040.0 MW were in generation request queues in the status of active, under construction or suspended. Of the total 277,040.0 MW in the queue, 117,313.1 MW (42.3 percent) have reached at least the SIS milestone and 159,726.9 MW (57.7 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 37,918.7 MW (13.7 percent) of new generation in the queue are expected to go into service.

Table 12-25 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by September 30, 2022. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of September 30, 2022.

Table 12-25 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: September 30, 2022

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Battery	65.5%	8.3%	15.1%	43.9%	21.5%	7.7%	1.3%	4.1%	0.3%	0.0%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	9.2%	11.7%	6.1%	1.2%	0.5%	0.0%	0.0%	0.0%
CT - Natural Gas	100.0%	98.3%	89.7%	42.2%	32.0%	0.2%	11.1%	23.6%	7.4%	2.5%	0.4%	0.0%	0.0%
CT - Oil	100.0%	N/A	1.2%	0.0%	0.0%	N/A	N/A	N/A	0.0%	30.8%	0.0%	N/A	N/A
CT - Other	28.8%	27.1%	36.1%	100.0%	0.0%	100.0%	N/A	0.0%	N/A	N/A	N/A	0.0%	N/A
Fuel Cell	N/A	N/A	N/A	N/A	N/A	67.4%	12.5%	0.0%	N/A	0.0%	N/A	0.0%	N/A
Hydro - Pumped Storage	N/A	N/A	N/A	N/A	N/A	100.0%	N/A	N/A	0.0%	0.0%	N/A	0.0%	N/A
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	N/A	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%	N/A
Nuclear	15.5%	1.6%	0.0%	100.0%	N/A	N/A	0.0%	71.6%	0.0%	N/A	0.0%	N/A	N/A
RICE - Natural Gas	N/A	N/A	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	N/A	N/A	N/A	0.0%	N/A
RICE - Oil	0.0%	0.0%	N/A	N/A	N/A	30.8%	N/A	N/A	N/A	N/A	N/A	N/A	0.0%
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	N/A	N/A	N/A	N/A
Solar	10.7%	8.1%	16.9%	24.4%	30.7%	22.5%	15.7%	2.0%	0.6%	0.0%	0.0%	0.0%	0.0%
Solar + Storage	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	N/A
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	22.4%	0.0%	N/A	N/A	N/A
Steam - Natural Gas	N/A	N/A	N/A	100.0%	0.0%	100.0%	100.0%	100.0%	N/A	N/A	0.0%	N/A	N/A
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	N/A
WInd	6.1%	3.4%	2.5%	5.8%	20.7%	12.5%	12.3%	2.6%	0.6%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	N/A	N/A	N/A	N/A	N/A
All	11.7%	19.0%	26.5%	34.3%	40.3%	11.8%	13.2%	3.8%	1.0%	0.1%	0.0%	0.0%	0.0%

Table 12-26 shows the total MW that went in service each year, by unit type, since 1999. 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.

Table 12-26 Total (MW Energy) by unit type and year project went in service: September 30, 2022

Unit Type	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	41.0	25.5	0.0	1.5	0.0
CC	0.0	0.0	100.0	2,108.0	2,725.0	2,845.0	15.1	1,196.0	22.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,881.4	88.0	3,424.7	1,200.9
CT - Natural Gas	0.0	401.6	316.0	2,442.0	173.7	61.3	528.0	39.3	77.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	497.9	72.0	212.0	388.0	104.0	127.0	328.4	93.5
CT - Oil	0.0	0.0	315.0	6.5	0.0	8.0	42.0	7.5	21.0	15.3	78.9	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0
CT - Other	0.0	0.0	10.0	0.0	0.0	4.1	0.0	0.0	11.0	6.9	0.0	18.2	0.0	72.8	17.6	6.0	8.0	5.9	0.0	0.0	3.2	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0	107.0	196.0	2.0	0.0	5.7	2.5	0.0	6.2	180.0	27.0	0.0	6.0	28.9	160.5	0.0	29.5	5.5	0.0	2.4	0.0	0.0
Nuclear	0.0	0.0	165.0	15.0	44.0	0.0	1,693.0	242.0	130.0	115.0	0.0	281.0	422.0	328.0	117.0	80.0	54.0	133.8	130.0	0.0	0.0	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0	23.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0
RICE - Other	0.0	1.2	0.0	2.9	13.7	0.0	27.5	44.9	86.6	57.6	38.8	13.8	43.0	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	300.8	332.9	285.3	560.0	1,175.0	807.5	221.1
Solar + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	718.0	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	0.0	22.5	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	1,053.3	632.2	622.0	1,183.5	326.6	1,485.1	150.0	500.0	455.0	363.3	700.7	762.0	535.0	1,008.6	310.0	0.0
Wind + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	12.0	422.8	967.5	4,727.4	3,342.4	3,009.1	2,362.1	2,460.4	1,502.9	2,713.8	1,447.7	2,243.1	3,829.8	3,256.9	742.7	3,001.4	4,550.8	7,040.5	5,384.5	12,411.9	4,170.8	2,473.0	4,883.1	1,515.5

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-27 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, biomass, renewable hybrid and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 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.

Table 12-27 Number of projects entered in the queue: September 30, 2022

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Total
1997	2	0	10	12
1998	0	0	13	13
1999	1	5	83	89
2000	2	3	72	77
2001	4	6	80	90
2002	3	14	31	48
2003	1	34	18	53
2004	4	17	32	53
2005	3	75	54	132
2006	8	64	79	151
2007	9	64	144	217
2008	3	101	111	215
2009	10	107	56	173
2010	5	370	66	441
2011	6	264	85	355
2012	2	59	98	159
2013	1	54	99	154
2014	0	100	92	192
2015	0	134	175	309
2016	2	298	99	399
2017	2	293	60	355
2018	1	344	95	440
2019	0	547	150	697
2020	2	782	213	997
2021	0	983	351	1,334
2022	0	284	123	407
Total	71	5,002	2,489	7,562

As of September 30, 2022, 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 (Table 12-28).

Table 12-28 Queue details by fuel group: September 30, 2022

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	0.2%	198.2	0.1%
Renewable	2,343	75.5%	209,019.6	75.4%
Traditional	755	24.3%	67,822.2	24.5%
Total	3,104	100.0%	277,040.0	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

While renewables currently make up the majority of both projects and nameplate MW in the 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 (Table 12-24). Table 12-29 shows the total MW of all projects in the queue as of September 30, 2022, in the status of active, suspended and under construction, by unit type. Table 12-29 also shows the total MW for each fuel type adjusted based on current historical completion rates and for battery, solar and wind ELCC derates. 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. 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. 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.

Table 12-29 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and ELCC battery, solar and wind derates (MW): September 30, 2022[55]

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and ELCC Adjusted MW in Queue
Battery	49,496.0	1,297.9	1,077.3
CC	12,727.4	7,478.1	7,478.1
CT - Natural Gas	5,078.8	3,257.2	3,257.2
CT - Oil	13.0	8.8	8.8
CT - Other	396.6	33.3	33.3
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	112.8	53.0	53.0
Nuclear	198.2	93.3	93.3
RICE - Natural Gas	14.4	3.7	3.7
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	127,624.5	18,223.0	9,840.4
Solar + Storage	37,385.3	37.2	20.1
Solar + Wind	209.0	0.0	0.0
Steam - Coal	65.0	23.1	23.1
Steam - Natural Gas	11.0	10.0	10.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	42,843.8	6,684.9	1,002.7
Wind + Storage	106.3	0.0	0.0
Total	277,040.0	37,918.7	23,616.2

Queue Analysis by Unit Type and Project Classification

Table 12-30 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through September 30, 2022. As of September 30, 2022, 7,562 projects, representing 795,209.6 MW, have entered the queue process since its inception. 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.

A total of 6,033 projects have been classified as new generation and 1,529 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 5,917 projects (78.2 percent) of all 7,562 generation queue projects to enter the queue since January 1, 1997.

55 The derate adjusted MW in this table are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.

Table 12-30 Status of all generation queue projects: January 1, 1997 through September 30, 2022

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	24	64	46	8	25	3	0	10	2	10	0	54	198	1	0	8	5	0	4	96	0	558
	Upgrade	7	108	119	15	5	0	3	19	42	9	2	16	43	0	0	56	10	0	8	13	0	475
Under Construction	New Generation	3	2	2	0	0	0	0	0	0	0	0	0	47	2	0	0	1	0	0	1	0	58
	Upgrade	0	7	11	7	0	1	0	0	1	0	0	0	12	1	0	1	0	0	0	3	0	44
Suspended	New Generation	4	4	3	0	0	0	0	0	0	0	0	0	44	15	0	0	0	0	0	0	1	71
	Upgrade	0	2	0	0	0	0	0	0	0	0	0	0	6	1	0	0	0	0	0	0	1	10
Withdrawn	New Generation	214	428	29	10	82	26	2	43	8	29	11	16	1,518	96	0	55	1	0	34	468	0	3,070
	Upgrade	56	101	16	13	13	2	0	5	13	0	3	3	80	2	0	15	0	0	2	31	0	355
Active	New Generation	387	5	3	0	6	0	2	5	0	1	0	0	1,420	349	2	0	0	0	1	95	0	2,276
	Upgrade	255	17	25	2	2	2	1	2	5	0	0	0	268	39	0	2	2	0	0	22	1	645
Total Projects	New Generation	632	503	83	18	113	29	4	58	10	40	11	70	3,227	463	2	63	7	0	39	660	1	6,033
	Upgrade	318	235	171	37	20	5	4	26	61	9	5	19	409	43	0	74	12	0	10	69	2	1,529

Table 12-31 shows the totals in Table 12-30 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 73.1 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 19.2 percent of hydro run of river upgrades were withdrawn and 7.7 percent of hydro run of river upgrades are active in the queue.

Table 12-31 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through September 30, 2022

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	3.8%	12.7%	55.4%	44.4%	22.1%	10.3%	0.0%	17.2%	20.0%	25.0%	0.0%	77.1%	6.1%	0.2%	0.0%	12.7%	71.4%	0.0%	10.3%	14.5%	0.0%	9.2%
	Upgrade	2.2%	46.0%	69.6%	40.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	40.0%	84.2%	10.5%	0.0%	0.0%	75.7%	83.3%	0.0%	80.0%	18.8%	0.0%	31.1%
Under Construction	New Generation	0.5%	0.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	0.4%	0.0%	0.0%	14.3%	0.0%	0.0%	0.2%	0.0%	1.0%
	Upgrade	0.0%	3.0%	6.4%	18.9%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	2.9%	2.3%	0.0%	1.4%	0.0%	0.0%	0.0%	4.3%	0.0%	2.9%
Suspended	New Generation	0.6%	0.8%	3.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	1.2%
	Upgrade	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	0.7%
Withdrawn	New Generation	33.9%	85.1%	34.9%	55.6%	72.6%	89.7%	50.0%	74.1%	80.0%	72.5%	100.0%	22.9%	47.0%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.9%	0.0%	50.9%
	Upgrade	17.6%	43.0%	9.4%	35.1%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	60.0%	15.8%	19.6%	4.7%	0.0%	20.3%	0.0%	0.0%	20.0%	44.9%	0.0%	23.2%
Active	New Generation	61.2%	1.0%	3.6%	0.0%	5.3%	0.0%	50.0%	8.6%	0.0%	2.5%	0.0%	0.0%	44.0%	75.4%	100.0%	0.0%	0.0%	0.0%	2.6%	14.4%	0.0%	37.7%
	Upgrade	80.2%	7.2%	14.6%	5.4%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%	65.5%	90.7%	0.0%	2.7%	16.7%	0.0%	0.0%	31.9%	50.0%	42.2%

Table 12-32 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 499 new generation wind projects that have been withdrawn from the queue as of September 30, 2022, (as shown in Table 12-30) constitute 87,759.9 MW. The 428 new generation combined cycle projects that have been withdrawn in the same time period constitute 214,586.7 MW.

Table 12-32 Status of all generation (MW) in the generation queue: January 1, 1997 through September 30, 2022

		Project MW																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	224.9	36,941.9	5,502.8	401.5	151.3	1.9	0.0	371.5	1,639.0	156.4	0.0	436.6	3,914.6	1.1	0.0	1,343.0	723.0	0.0	60.9	10,461.5	0.0	62,331.9
	Upgrade	44.4	7,447.5	2,923.0	125.1	12.3	0.0	390.0	387.6	2,310.8	17.3	27.3	50.7	295.6	0.0	0.0	976.5	225.5	0.0	667.8	238.7	0.0	16,140.1
Under Construction	New Generation	34.0	2,250.0	208.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,286.4	2.6	0.0	0.0	5.0	0.0	0.0	200.0	0.0	5,986.0
	Upgrade	0.0	1,022.7	249.0	9.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	260.6	3.2	0.0	36.0	0.0	0.0	0.0	0.0	0.0	1,627.5
Suspended	New Generation	29.0	2,680.0	1,368.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,397.9	54.4	0.0	0.0	0.0	0.0	0.0	0.0	90.0	6,619.3
	Upgrade	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.5	50.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	235.8
Withdrawn	New Generation	6,849.2	214,586.7	4,426.3	1,735.0	1,244.2	5.5	500.0	2,025.5	6,521.0	481.2	58.9	88.6	49,817.8	9,224.8	0.0	33,511.6	27.0	0.0	1,050.9	86,116.5	0.0	418,270.7
	Upgrade	1,354.6	12,910.0	984.5	589.0	72.5	0.9	0.0	105.1	966.0	0.0	19.6	10.0	1,845.5	3.7	0.0	885.0	0.0	0.0	37.1	1,643.4	0.0	21,426.9
Active	New Generation	39,217.8	5,401.0	1,838.0	0.0	396.6	0.0	700.0	58.6	0.0	14.4	0.0	0.0	110,610.6	35,816.9	209.0	0.0	0.0	0.0	20.0	38,300.7	0.0	232,583.5
	Upgrade	10,215.2	1,288.7	1,415.8	4.0	0.0	5.0	30.0	54.2	154.2	0.0	0.0	0.0	10,984.4	1,458.3	0.0	29.0	6.0	0.0	0.0	4,343.0	0.0	29,987.9
Total Projects	New Generation	46,354.9	261,859.6	13,343.1	2,136.5	1,792.2	7.4	1,200.0	2,455.5	8,160.0	652.0	58.9	525.2	170,027.4	45,099.7	209.0	34,854.6	755.0	0.0	1,131.8	135,078.7	90.0	725,791.4
	Upgrade	11,614.2	22,753.9	5,572.3	727.1	84.8	8.9	420.0	546.9	3,475.0	17.3	46.9	60.7	13,470.6	1,515.2	0.0	1,926.5	231.5	0.0	704.9	6,225.2	16.3	69,418.2

Table 12-33 shows the MW totals in Table 12-32 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 57.6 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and September 30, 2022.

Table 12-33 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through September 30, 2022

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0.5%	14.1%	41.2%	18.8%	8.4%	26.2%	0.0%	15.1%	20.1%	24.0%	0.0%	83.1%	2.3%	0.0%	0.0%	3.9%	95.8%	0.0%	5.4%	7.7%	0.0%	8.6%
	Upgrade	0.4%	32.7%	52.5%	17.2%	14.5%	0.0%	92.9%	70.9%	66.5%	100.0%	58.2%	83.5%	2.2%	0.0%	0.0%	50.7%	97.4%	0.0%	94.7%	3.8%	0.0%	23.3%
Under Construction	New Generation	0.1%	0.9%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.1%	0.0%	0.8%
	Upgrade	0.0%	4.5%	4.5%	1.2%	0.0%	33.5%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	1.9%	0.2%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%
Suspended	New Generation	0.1%	1.0%	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.9%
	Upgrade	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.3%
Withdrawn	New Generation	14.8%	81.9%	33.2%	81.2%	69.4%	73.8%	41.7%	82.5%	79.9%	73.8%	100.0%	16.9%	29.3%	20.5%	0.0%	96.1%	3.6%	0.0%	92.9%	63.8%	0.0%	57.6%
	Upgrade	11.7%	56.7%	17.7%	81.0%	85.5%	10.6%	0.0%	19.2%	27.8%	0.0%	41.8%	16.5%	13.7%	0.2%	0.0%	45.9%	0.0%	0.0%	5.3%	26.4%	0.0%	30.9%
Active	New Generation	84.6%	2.1%	13.8%	0.0%	22.1%	0.0%	58.3%	2.4%	0.0%	2.2%	0.0%	0.0%	65.1%	79.4%	100.0%	0.0%	0.0%	0.0%	1.8%	28.4%	0.0%	32.0%
	Upgrade	88.0%	5.7%	25.4%	0.6%	0.0%	55.9%	7.1%	9.9%	4.4%	0.0%	0.0%	0.0%	81.5%	96.2%	0.0%	1.5%	2.6%	0.0%	0.0%	69.8%	0.0%	43.2%

Table 12-34 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 71.0 percent of all new projects entering the generation queue have been combined cycle (10.4 percent), wind (16.8 percent) or solar projects (43.8 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through September 30, 2022, 46,930.2 MW of renewable hybrid units have entered the queue.

Table 12-34 Queue project MW by unit type and queue entry year: January 1, 1997 through September 30, 2022

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	3,648.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,340.0
1998	0.0	5,481.0	745.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,226.0
1999	0.0	28,862.7	2,061.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	31,862.2
2000	0.0	19,015.8	493.6	6.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	19,755.9
2001	0.0	25,411.7	248.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,361.8
2002	0.0	3,704.0	11.7	0.0	70.5	0.0	0.0	252.0	236.0	8.0	23.3	1.0	0.0	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	6,992.4
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	30.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,614.7	0.0	8,483.1
2005	0.0	5,824.6	961.0	31.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,114.9
2006	0.0	3,543.1	434.3	607.5	73.1	0.0	0.0	159.0	5,254.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,385.1	0.0	27,393.6
2007	0.0	13,944.6	941.2	209.2	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	50.5	18,455.6	0.0	43,623.9
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,198.0	0.0	0.0	192.3	10,913.6	0.0	41,621.2
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,672.6	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,891.3
2011	24.1	19,744.0	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,269.9
2012	142.6	18,014.8	282.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,746.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,407.9	0.0	14,063.4
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,590.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,100.6
2015	546.9	27,540.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,920.7	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,550.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	59.0	23.5	0.0	38.9	11,605.5	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,755.9
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,652.8	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,726.3
2018	1,463.7	11,080.1	2,647.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,804.0	4,543.9	0.0	49.0	0.0	0.0	0.0	17,707.9	0.0	58,041.3
2019	5,511.3	3,332.5	1,587.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,612.5	9,557.9	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,812.6
2020	11,313.9	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,481.6	10,309.6	199.0	0.0	11.0	0.0	0.0	6,915.9	0.0	67,311.7
2021	25,907.1	2,129.0	771.0	0.0	396.6	5.0	30.0	23.5	0.0	14.4	0.0	0.0	49,118.7	14,871.2	10.0	0.0	0.0	0.0	20.0	11,160.0	0.0	104,456.5
2022	12,232.0	103.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	12,803.2	6,819.9	0.0	0.0	0.0	0.0	0.0	9,884.3	0.0	41,869.0
Total	57,969.1	284,613.5	18,915.4	2,863.6	1,876.9	16.3	1,620.0	3,002.4	11,635.0	669.3	105.8	585.9	183,498.0	46,614.9	209.0	36,781.1	986.5	0.0	1,836.7	141,303.9	106.3	795,209.6

Combined Cycle Project Analysis

Table 12-35 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 37 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, eight projects (21.6 percent) are located in the APS Zone.

Table 12-35 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through September 30, 2022

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	6	3	4	2	2	0	2	0	7	2	0	7	4	0	5	2	4	8	5	0	64
	Upgrade	3	13	9	5	0	5	0	0	0	16	4	0	6	3	0	13	4	4	9	14	0	108
Under Construction	New Generation	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	3	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	7
Suspended	New Generation	0	2	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	2
Withdrawn	New Generation	22	20	45	13	8	16	1	1	2	18	16	3	25	25	0	40	41	33	42	55	2	428
	Upgrade	8	8	10	4	0	4	0	1	0	11	5	0	7	7	0	3	5	5	8	15	0	101
Active	New Generation	0	0	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	1	3	1	0	2	0	0	0	3	1	0	0	0	0	1	0	2	2	1	0	17
Total Projects	New Generation	23	29	52	19	10	20	1	3	2	25	18	3	32	29	0	45	43	37	50	60	2	503
	Upgrade	11	25	23	10	0	11	0	1	0	30	10	0	13	11	0	17	11	11	20	31	0	235

Table 12-36 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 12,727.4 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 4,660.0 MW (36.6 percent) are located in the APS Zone.

Table 12-36 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through September 30, 2022

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	4,511.0	1,970.0	3,751.0	140.0	1,800.9	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,142.0	1,948.5	0.0	36,941.9
	Upgrade	229.0	475.0	939.7	344.0	0.0	633.6	0.0	0.0	0.0	978.0	42.0	0.0	110.0	83.9	0.0	1,075.5	142.3	228.6	1,320.0	845.9	0.0	7,447.5
Under Construction	New Generation	0.0	1,100.0	0.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,250.0
	Upgrade	0.0	825.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	1,022.7
Suspended	New Generation	0.0	1,150.0	0.0	955.0	0.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,680.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	85.0
Withdrawn	New Generation	8,092.4	13,559.5	21,832.1	8,641.0	3,122.1	10,817.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	12,837.6	13,001.0	0.0	21,690.0	16,114.0	20,663.2	18,917.7	24,244.6	6.9	214,586.7
	Upgrade	157.0	746.0	1,284.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	959.0	0.0	404.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	12,910.0
Active	New Generation	0.0	0.0	4,461.0	940.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,401.0
	Upgrade	0.0	285.0	179.0	58.0	0.0	111.7	0.0	0.0	0.0	99.0	451.0	0.0	0.0	0.0	0.0	5.0	0.0	45.0	55.0	0.0	0.0	1,288.7
Total Projects	New Generation	8,742.4	20,320.5	28,263.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	14,503.4	15,558.0	0.0	24,355.0	18,014.0	22,223.2	24,059.7	26,193.1	6.9	261,859.6
	Upgrade	386.0	2,331.0	2,422.7	1,038.0	0.0	2,480.3	0.0	36.0	0.0	1,857.4	1,452.0	0.0	514.0	1,900.9	0.0	1,320.5	1,267.9	502.7	2,129.6	3,114.9	0.0	22,753.9

Combustion Turbine – Natural Gas Project Analysis

Table 12-37 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 44 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, eight projects (18.2 percent) are located in the COMED Zone.

Table 12-37 Status of all combustion turbine – natural gas generation queue projects by zone (number of projects): January 1, 1997 through September 30, 2022

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	6	0	3	0	0	0	2	3	3	0	2	1	0	2	4	2	4	9	0	46
	Upgrade	4	10	10	2	0	17	6	0	0	27	8	0	5	2	0	4	4	2	4	14	0	119
Under Construction	New Generation	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	2
	Upgrade	0	0	0	2	0	2	0	0	0	0	0	0	0	3	0	0	4	0	0	0	0	11
Suspended	New Generation	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	1	6	0	0	2	1	1	0	0	4	0	1	1	0	0	1	5	0	1	5	0	29
	Upgrade	2	1	1	1	0	3	2	0	1	3	0	0	0	1	0	0	1	0	0	0	0	16
Active	New Generation	0	1	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	3
	Upgrade	2	3	1	5	0	5	1	0	1	1	0	0	0	0	0	0	1	5	0	0	0	25
Total Projects	New Generation	7	7	6	0	5	2	1	0	2	9	3	1	3	1	0	3	11	2	5	15	0	83
	Upgrade	8	14	12	10	0	27	9	0	2	31	8	0	5	6	0	4	10	7	4	14	0	171

Table 12-38 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 5,078.8 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,138.0 MW (22.4 percent) are located in the DOM Zone.

Table 12-38 Status of all combustion turbine – natural gas queue projects by zone (MW): January 1, 1997 through September 30, 2022

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	219.4	1,081.0	110.0	0.0	520.0	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	5,502.8
	Upgrade	43.7	227.0	269.7	40.0	0.0	478.0	83.5	0.0	0.0	905.7	86.0	0.0	200.0	36.1	0.0	42.0	28.0	16.0	252.3	215.0	0.0	2,923.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	190.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	208.0
	Upgrade	0.0	0.0	0.0	5.0	0.0	220.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	0.0	0.0	12.5	0.0	0.0	0.0	0.0	249.0
Suspended	New Generation	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	463.0	0.0	0.0	675.0	0.0	1,368.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	7.5	1,519.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	4,426.3
	Upgrade	165.5	6.0	4.0	25.0	0.0	373.0	104.0	0.0	15.0	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	0.0	0.0	0.0	0.0	984.5
Active	New Generation	0.0	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,838.0
	Upgrade	0.0	142.1	30.0	518.7	0.0	554.2	20.0	0.0	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	55.3	0.0	0.0	0.0	1,415.8
Total Projects	New Generation	598.2	2,219.0	1,176.0	0.0	176.6	200.0	104.0	0.0	219.4	3,288.8	110.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	13,343.1
	Upgrade	209.2	375.1	303.7	588.7	0.0	1,625.2	207.5	0.0	18.5	962.7	86.0	0.0	200.0	47.6	0.0	42.0	367.5	71.3	252.3	215.0	0.0	5,572.3

Wind Project Analysis

Table 12-39 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 121 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 47 projects (38.8 percent) are located in the COMED Zone.

Table 12-39 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through September 30, 2022

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	19	17	0	0	26	0	0	0	2	0	0	0	0	0	0	23	0	8	0	0	96
	Upgrade	0	0	3	0	0	5	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	13
Under Construction	New Generation	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	18	116	46	10	0	109	14	0	0	21	13	1	7	0	0	0	63	0	49	1	0	468
	Upgrade	2	2	7	0	0	8	0	0	0	3	1	0	0	0	0	0	6	0	2	0	0	31
Active	New Generation	6	18	6	1	0	35	0	0	0	8	9	0	7	0	0	0	3	0	1	1	0	95
	Upgrade	0	1	1	0	0	8	0	0	0	0	4	0	5	0	0	0	3	0	0	0	0	22
Total Projects	New Generation	25	153	69	11	0	171	14	0	0	31	22	1	14	0	0	0	89	0	58	2	0	660
	Upgrade	2	3	11	0	0	24	0	0	0	3	5	0	5	0	0	0	14	0	2	0	0	69

Table 12-40 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 42,843.8 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 10,372.5 MW (24.2 percent) are located in the JCPLC Zone.

Table 12-40 Status of all wind generation queue projects by zone (MW): January 1, 1997 through September 30, 2022

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,544.6	1,327.0	0.0	0.0	4,088.9	0.0	0.0	0.0	220.0	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,461.5
	Upgrade	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	4,643.6	23,743.4	3,552.2	1,814.0	0.0	25,514.8	2,080.0	0.0	0.0	4,988.4	3,240.8	150.3	7,397.0	0.0	0.0	0.0	5,257.0	0.0	3,715.2	20.0	0.0	86,116.5
	Upgrade	5.0	370.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	30.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,643.4
Active	New Generation	3,441.6	3,506.3	751.5	297.7	0.0	8,799.8	0.0	0.0	0.0	5,418.8	6,414.2	0.0	7,959.2	0.0	0.0	0.0	236.9	0.0	174.8	1,300.0	0.0	38,300.7
	Upgrade	0.0	16.6	207.6	0.0	0.0	483.4	0.0	0.0	0.0	0.0	955.3	0.0	2,413.3	0.0	0.0	0.0	266.9	0.0	0.0	0.0	0.0	4,343.0
Total Projects	New Generation	8,092.7	30,794.3	5,630.7	2,111.7	0.0	38,603.5	2,080.0	0.0	0.0	10,627.2	9,655.0	150.3	15,356.2	0.0	0.0	0.0	6,540.8	0.0	4,116.5	1,320.0	0.0	135,078.7
	Upgrade	5.0	386.6	332.0	0.0	0.0	1,452.2	0.0	0.0	0.0	114.0	985.3	0.0	2,413.3	0.0	0.0	0.0	530.7	0.0	6.0	0.0	0.0	6,225.2

Solar Project Analysis

Table 12-41 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 1,797 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 394 projects (21.9 percent) are located in the DOM Zone.

Table 12-41 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through September 30, 2022

		Number of Projects																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	10	9	10	0	1	1	1	1	0	49	12	0	53	0	0	1	1	1	2	46	0	198
	Upgrade	2	2	3	0	0	0	0	2	0	9	10	0	11	0	0	0	1	0	3	0	0	43
Under Construction	New Generation	1	3	2	1	0	1	1	0	1	21	6	1	1	3	0	0	1	1	0	3	0	47
	Upgrade	0	3	0	0	0	1	0	0	0	4	0	0	0	0	0	0	0	0	0	4	0	12
Suspended	New Generation	0	2	11	3	0	2	1	1	0	10	2	1	0	4	0	0	4	0	3	0	0	44
	Upgrade	0	0	1	0	0	0	0	1	0	1	0	1	2	0	0	0	0	0	0	0	0	6
Withdrawn	New Generation	192	134	101	36	15	47	27	16	2	256	156	16	198	29	1	10	78	23	60	121	0	1,518
	Upgrade	4	6	4	5	0	6	1	0	0	23	3	0	9	3	0	0	10	3	0	3	0	80
Active	New Generation	22	287	131	86	5	73	33	9	5	308	57	63	28	37	2	11	170	11	78	4	0	1,420
	Upgrade	2	71	23	22	0	16	12	1	1	50	11	5	1	10	2	0	19	0	22	0	0	268
Total Projects	New Generation	225	435	255	126	21	124	63	27	8	644	233	81	280	73	3	22	254	36	143	174	0	3,227
	Upgrade	8	82	31	27	0	23	13	4	1	87	24	6	23	13	2	0	30	3	25	7	0	409

Table 12-42 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 127,624.5 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 43,642.8 MW (34.2 percent) are located in the AEP Zone.

Table 12-42 Status of all solar generation queue projects by zone (MW): January 1, 1997 through September 30, 2022

		Project MW																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	65.0	314.7	140.5	0.0	1.1	9.0	2.5	125.0	0.0	2,432.4	150.4	0.0	397.9	0.0	0.0	3.3	13.5	2.5	15.0	241.9	0.0	3,914.6
	Upgrade	0.0	150.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	46.3	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	295.6
Under Construction	New Generation	2.6	377.0	80.0	180.0	0.0	50.0	400.0	0.0	17.1	1,753.4	231.6	50.0	19.8	60.0	0.0	0.0	20.0	27.5	0.0	17.5	0.0	3,286.4
	Upgrade	0.0	167.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	39.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	260.6
Suspended	New Generation	0.0	97.9	298.8	375.0	0.0	32.5	178.0	70.0	0.0	856.8	294.0	80.0	0.0	12.0	0.0	0.0	60.2	0.0	42.8	0.0	0.0	2,397.9
	Upgrade	0.0	0.0	15.9	0.0	0.0	0.0	0.0	10.0	0.0	20.0	0.0	20.0	18.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.5
Withdrawn	New Generation	2,120.2	9,360.4	2,790.7	1,923.7	121.6	3,406.2	2,324.6	689.4	33.0	15,912.3	2,661.6	998.9	1,623.6	1,011.7	78.0	98.2	2,630.6	438.0	1,025.1	570.3	0.0	49,817.8
	Upgrade	172.5	126.0	32.9	213.0	0.0	110.0	20.0	0.0	0.0	1,068.8	5.0	0.0	23.8	15.0	0.0	0.0	53.7	3.6	0.0	1.3	0.0	1,845.5
Active	New Generation	617.7	38,900.9	5,600.1	5,597.5	154.9	11,891.2	2,754.9	578.9	63.5	27,176.3	1,802.1	5,772.2	418.9	596.4	340.0	145.4	5,745.4	212.6	2,203.8	37.9	0.0	110,610.6
	Upgrade	48.0	4,100.0	554.4	916.7	0.0	1,643.0	225.5	20.0	8.3	2,081.4	74.0	233.8	8.8	193.0	90.0	0.0	465.5	0.0	322.1	0.0	0.0	10,984.4
Total Projects	New Generation	2,805.5	49,050.9	8,909.9	8,076.2	277.6	15,388.9	5,659.9	1,463.3	113.6	48,131.1	5,139.6	6,901.1	2,460.2	1,680.1	418.0	246.9	8,469.6	680.7	3,286.7	867.6	0.0	170,027.4
	Upgrade	220.5	4,543.0	603.1	1,129.7	0.0	1,803.0	245.5	105.0	8.3	3,256.3	78.9	253.8	65.5	208.0	90.0	0.0	519.2	3.6	332.1	5.1	0.0	13,470.6

Battery Project Analysis

Table 12-43 shows the status of all battery generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 649 battery projects currently active, suspended or under construction in the PJM generation queue, 223 projects (34.4 percent) are located in the DOM Zone.

Table 12-43 Status of all battery generation queue projects by zone (number of projects): January 1, 1997 through September 30, 2022

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	2	3	0	0	8	1	4	0	0	0	0	2	0	0	1	0	0	1	2	0	24
	Upgrade	0	1	0	0	0	0	1	1	0	0	0	0	2	0	0	0	2	0	0	0	0	7
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	2	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	7	33	4	7	25	24	3	3	1	30	17	1	36	4	0	4	4	1	6	4	0	214
	Upgrade	4	8	5	2	0	5	2	1	0	10	2	0	6	2	0	3	5	0	1	0	0	56
Active	New Generation	15	73	14	13	8	36	1	2	4	142	16	5	18	6	0	0	8	6	8	12	0	387
	Upgrade	6	47	19	11	1	41	5	1	0	80	7	3	5	5	0	0	19	0	4	1	0	255
Total Projects	New Generation	22	108	21	20	33	68	5	9	5	173	33	6	59	10	0	5	12	7	16	20	0	632
	Upgrade	10	56	24	13	1	46	8	3	0	90	9	3	13	7	0	3	26	0	5	1	0	318

Table 12-44 shows the status of all battery projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 49,496.0 MW of battery generation currently active, suspended or under construction in the PJM generation queue, 15,138.2 MW (30.6 percent) are located in the DOM Zone.

Table 12-44 Status of all battery generation queue projects by zone (MW): January 1, 1997 through September 30, 2022

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	6.0	39.9	0.0	0.0	87.0	12.0	16.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	224.9
	Upgrade	0.0	4.0	0.0	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	44.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	20.0	7.0	0.0	29.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	161.0	1,419.0	187.0	206.1	260.6	779.0	319.9	75.5	20.0	1,348.4	350.0	20.3	804.1	214.7	0.0	4.3	360.0	20.0	289.8	9.5	0.0	6,849.2
	Upgrade	20.0	302.2	169.0	20.3	0.0	325.0	95.0	20.0	0.0	183.0	14.0	0.0	55.1	30.0	0.0	60.0	41.0	0.0	20.0	0.0	0.0	1,354.6
Active	New Generation	1,739.5	8,391.5	1,379.5	1,810.0	1,083.5	5,064.8	85.0	225.0	205.0	13,209.2	909.0	176.0	766.8	526.2	0.0	0.0	635.8	796.0	455.0	1,760.0	0.0	39,217.8
	Upgrade	0.0	2,594.4	1,565.3	408.0	115.0	2,311.3	255.0	52.2	0.0	1,909.0	155.0	0.0	24.0	429.0	0.0	0.0	362.0	0.0	20.0	15.0	0.0	10,215.2
Total Projects	New Generation	1,900.5	9,816.5	1,606.4	2,016.1	1,344.1	5,930.8	416.9	316.5	225.0	14,577.6	1,259.0	196.3	1,626.9	740.9	0.0	5.3	995.8	816.0	784.8	1,779.5	0.0	46,354.9
	Upgrade	20.0	2,900.6	1,734.3	428.3	115.0	2,636.3	358.0	76.2	0.0	2,092.0	169.0	0.0	79.1	459.0	0.0	60.0	431.4	0.0	40.0	15.0	0.0	11,614.2

Renewable Hybrid Project Analysis

Table 12-45 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone.[56] Of the 412 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 109 projects (26.5 percent) are located in the AEP Zone.

Table 12-45 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through September 30, 2022

		Number of Projects																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	7	0	0	0	0	0	0	0	0	0	0	7	0	0	1	0	1	0	0	16
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	2
Withdrawn	New Generation	4	11	8	5	0	6	0	0	0	30	2	8	0	1	0	0	4	1	6	10	0	96
	Upgrade	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	2
Active	New Generation	5	100	24	12	0	18	10	2	3	67	4	32	7	5	1	1	21	3	35	1	0	351
	Upgrade	1	8	4	3	0	2	3	0	0	7	0	4	0	1	0	0	1	0	6	0	0	40
Total Projects	New Generation	9	111	39	17	0	24	10	2	3	97	6	40	7	13	1	1	26	4	42	14	0	466
	Upgrade	1	9	5	3	0	2	3	0	0	8	0	4	0	2	0	0	1	0	7	0	0	45

Table 12-46 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2022, by zone. Of the 37,700.6 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 15,638.8 MW (41.5 percent) are located in the AEP Zone.

Table 12-46 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through September 30, 2022

		Project MW																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	0.0	2.6
	Upgrade	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Suspended	New Generation	0.0	0.0	32.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.9	0.0	0.0	3.0	0.0	90.0	0.0	0.0	144.4
	Upgrade	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	66.3
Withdrawn	New Generation	14.5	3,460.8	568.0	334.9	0.0	986.9	0.0	0.0	0.0	2,289.9	104.5	1,004.0	0.0	20.0	0.0	0.0	184.2	20.0	201.0	36.1	0.0	9,224.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	161.0	14,970.6	2,515.7	831.5	0.0	2,710.5	460.9	50.0	107.5	7,134.8	270.0	2,929.1	235.0	143.2	178.5	5.0	1,370.6	1,452.0	480.0	20.0	0.0	36,025.9
	Upgrade	60.0	665.0	0.0	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	165.0	0.0	0.0	0.0	0.0	38.2	0.0	211.0	0.0	0.0	1,458.3
Total Projects	New Generation	175.5	18,431.4	3,116.3	1,166.4	0.0	3,697.4	460.9	50.0	107.5	9,424.7	374.5	3,933.1	235.0	182.1	178.5	5.0	1,557.9	1,472.0	771.0	59.7	0.0	45,398.7
	Upgrade	60.0	668.2	16.3	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	165.0	0.0	3.7	0.0	0.0	38.2	0.0	261.0	0.0	0.0	1,531.5

56 PJM does not currently have a definition of a hybrid resource.

Relationship Between Project Developer and Transmission Owner

A transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[57] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation or transmission of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-47 shows the relationship between the project developer and transmission owner for all project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A project where the developer is not affiliated with the transmission owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in the DUKE Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DUKE Zone. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in the DUKE Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 795,209.6 MW that have entered the queue during the time period of January 1, 1997, through September 30, 2022, 69,805.3 MW (8.8 percent) have been submitted by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building in their own service territory. Of the 38,476.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through September 30, 2022, 13,782.3 MW (35.8 percent) were submitted by PSEG or one of their affiliated companies.

57 See OATT § 1 (Transmission Owner).

Table 12-47 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: September 30, 2022

				MW by Unit Type																						
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total	Percent of Total
AEP	AEP	Related	52	116.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	299.7	180.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,532.1	3.5%
		Unrelated	1,104	12,601.1	21,973.5	2,594.1	7.5	506.5	0.0	0.0	453.6	0.0	12.0	0.0	75.4	53,294.2	18,919.6	0.0	10,399.0	0.0	0.0	452.0	31,180.9	0.0	152,469.3	96.5%
AES	DAY	Related	14	20.0	0.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,436.0	11.9%
		Unrelated	122	754.9	1,150.0	264.5	0.0	15.7	0.0	0.0	0.0	0.0	0.0	0.0	10.0	5,883.9	500.9	0.0	0.0	0.0	0.0	0.0	2,080.0	0.0	10,660.0	88.1%
DUQ	DUQ	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	47	225.0	665.0	237.9	40.0	19.2	0.0	0.0	194.6	1,879.0	0.0	0.0	0.0	121.9	107.5	0.0	2,810.0	0.0	0.0	20.0	0.0	0.0	6,320.1	100.0%
DOM	DOM	Related	192	1,096.7	11,378.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	6,029.9	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	26,102.9	22.3%
		Unrelated	1,108	15,572.9	9,268.5	2,205.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	45,357.5	9,606.7	0.0	20.0	0.0	0.0	316.3	7,955.2	0.0	90,695.1	77.7%
DUKE	DUKE	Related	12	37.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	178.7	6.1%
		Unrelated	42	355.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	1,462.9	40.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	2,772.6	93.9%
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8	6.5%
		Unrelated	143	196.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,154.9	4,098.1	0.0	0.0	0.0	0.0	0.0	150.3	0.0	11,842.5	93.5%
Exelon	ACEC	Related	4	0.0	530.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	538.3	2.3%
		Unrelated	380	1,920.5	8,598.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	0.0	10.3	3,017.7	235.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	23,131.5	97.7%
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	117.2	0.0	0.0	8.5	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	539.2	7.5%
		Unrelated	73	1,436.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	1,640.0	1.3	0.0	0.0	257.6	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	6,693.1	92.5%
	COMED	Related	17	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,490.0	1.6%
		Unrelated	579	8,567.1	16,823.2	1,529.2	42.0	65.2	5.0	0.0	22.7	0.0	35.0	0.0	67.7	17,182.9	3,518.4	199.0	1,926.0	91.0	0.0	90.0	40,055.7	0.0	90,220.1	98.4%
	DPL	Related	4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4	0.0%
		Unrelated	407	1,427.0	6,916.6	196.0	344.2	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	5,211.2	374.5	0.0	653.0	15.0	0.0	65.0	10,640.3	0.0	25,969.9	100.0%
	PECO	Related	31	40.0	6,415.0	5.0	83.0	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	7,252.8	26.4%
		Unrelated	96	25.3	19,260.5	596.5	8.5	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	246.9	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,178.4	73.6%
	PEPCO	Related	5	1.0	503.0	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508.0	1.8%
		Unrelated	114	815.0	22,222.9	76.3	9.0	5.0	0.0	0.0	0.0	1,640.0	32.0	0.0	0.0	684.3	1,472.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	26,962.5	98.2%
First Energy	APS	Related	10	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.2	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,234.2	5.3%
		Unrelated	620	3,340.7	29,232.8	1,479.7	0.0	84.4	0.0	0.0	597.3	0.0	154.4	53.8	25.4	9,441.9	3,116.3	0.0	4,092.0	0.0	0.0	184.4	5,962.7	16.3	57,782.0	94.7%
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0	5.4%
		Unrelated	270	2,444.4	13,647.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	6.6	6.9	9,205.9	1,226.5	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	29,490.8	94.6%
	JCPLC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0	0.1%
		Unrelated	464	1,706.0	15,017.4	722.1	0.0	4.8	0.6	30.0	1.6	0.0	0.6	0.0	12.8	2,513.7	235.0	0.0	0.0	0.0	0.0	30.0	17,769.5	0.0	38,044.0	99.9%
	MEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	200	1,199.9	17,458.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,888.1	185.8	0.0	0.0	0.0	0.0	84.0	0.0	0.0	22,255.0	100.0%
	PE	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0	5.4%
		Unrelated	579	1,427.2	18,747.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8	8,988.7	1,596.1	0.0	561.0	590.0	0.0	525.0	7,071.6	0.0	41,687.3	94.6%
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5	100.0%
PPL	PPL	Related	24	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,650.0	0.0	0.0	0.0	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,255.8	9.0%
		Unrelated	428	824.8	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	438.0	19.9	2.4	44.7	3,494.1	942.0	0.0	6,896.6	0.0	0.0	31.0	4,122.5	90.0	42,842.5	91.0%
PSEG	PSEG	Related	107	0.0	11,336.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	175.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	13,782.3	35.8%
		Unrelated	277	1,794.5	17,971.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	697.3	56.1	0.0	0.0	25.0	0.0	0.0	1,320.0	0.0	24,694.4	64.2%
Con Ed	REC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9	100.0%
Total		Related	501	1,334.5	37,874.4	4,226.8	183.0	4.0	0.0	374.0	396.4	5,945.0	0.0	0.0	68.5	6,884.5	200.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	69,805.3	8.8%
		Unrelated	7,061	56,634.7	246,739.1	14,688.6	2,680.6	1,872.9	16.3	1,246.0	2,606.0	5,690.0	669.3	105.8	517.4	176,613.4	46,414.2	209.0	27,492.6	751.5	0.0	1,832.7	138,517.9	106.3	725,404.4	91.2%

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-48 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and project status. Of the 47,662.1 combined cycle project MW that are in service or currently under construction, 8,814.6 MW (18.5 percent) have been developed by transmission owners building in their own service territory. EKPC is the transmission owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue in the EKPC Zone during the time period of January 1, 1997, through September 30, 2022, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-48 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: September 30, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0	3.0%
		Unrelated	285.0	4,308.0	1,925.0	1,150.0	14,305.5	21,973.5	97.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	1,150.0	1,150.0	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0	100.0%
DOM	DOM	Related	75.0	4,762.5	0.0	0.0	6,541.0	11,378.5	55.1%
		Unrelated	24.0	2,044.1	0.0	0.0	7,200.4	9,268.5	44.9%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	36.0	36.0	5.1%
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5	94.9%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8	82.9%
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0	17.1%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	530.0	530.0	5.8%
		Unrelated	0.0	879.0	0.0	0.0	7,719.4	8,598.4	94.2%
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0	7.7%
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1	92.3%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	111.7	2,434.5	1,150.0	575.0	12,552.0	16,823.2	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	451.0	361.2	0.0	0.0	6,104.4	6,916.6	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	6,415.0	6,415.0	25.0%
		Unrelated	5.0	3,740.5	0.0	0.0	15,515.0	19,260.5	75.0%
	PEPCO	Related	0.0	80.0	0.0	0.0	423.0	503.0	2.2%
		Unrelated	45.0	1,708.6	0.0	0.0	20,469.3	22,222.9	97.8%
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0	4.7%
		Unrelated	4,640.0	2,384.7	20.0	0.0	22,188.1	29,232.8	95.3%
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0	10.9%
		Unrelated	998.0	4,095.0	0.0	955.0	7,599.0	13,647.0	89.1%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	1,775.8	0.0	0.0	13,241.6	15,017.4	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	2,640.9	75.0	0.0	14,743.0	17,458.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	534.0	534.0	2.8%
		Unrelated	0.0	2,042.3	0.0	85.0	16,620.6	18,747.9	97.2%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0	8.6%
		Unrelated	55.0	5,862.0	51.6	0.0	17,959.7	23,928.3	91.4%
PSEG	PSEG	Related	0.0	1,988.0	51.1	0.0	9,297.0	11,336.1	38.7%
		Unrelated	0.0	806.4	0.0	0.0	17,165.5	17,971.9	61.3%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9	100.0%
Total		Related	75.0	8,763.5	51.1	0.0	28,984.8	37,874.4	13.3%
		Unrelated	6,614.7	35,625.9	3,221.6	2,765.0	198,511.8	246,739.1	86.7%

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-49 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and project status. Of the 8,882.8 CT – natural gas project MW that are in service or currently under construction, 1,803.0 (20.3 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through September 30, 2022, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-49 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: September 30, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	842.1	227.0	0.0	0.0	1,525.0	2,594.1	100.0%
AES	DAY	Related	0.0	47.0	0.0	0.0	0.0	47.0	15.1%
		Unrelated	20.0	36.5	0.0	0.0	208.0	264.5	84.9%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3.5	219.4	0.0	0.0	15.0	237.9	100.0%
DOM	DOM	Related	1,138.0	824.0	0.0	0.0	83.7	2,045.7	48.1%
		Unrelated	0.0	1,162.7	0.0	0.0	1,043.1	2,205.8	51.9%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	73.0	73.0	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	404.4	0.0	230.0	173.0	807.4	100.0%
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0	5.7%
		Unrelated	0.0	13.0	0.0	0.0	153.6	166.6	94.3%
	COMED	Related	296.0	0.0	0.0	0.0	0.0	296.0	16.2%
		Unrelated	258.2	478.0	410.0	0.0	383.0	1,529.2	83.8%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	196.0	0.0	0.0	0.0	196.0	100.0%
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.8%
		Unrelated	0.0	596.0	0.0	0.0	0.5	596.5	99.2%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	55.3	21.0	0.0	0.0	0.0	76.3	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	30.0	1,445.7	0.0	0.0	4.0	1,479.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	518.7	40.0	5.0	0.0	25.0	588.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	720.0	0.0	0.0	2.1	722.1	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	46.1	11.5	0.0	0.0	57.6	100.0%
	PE	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.3%
		Unrelated	92.0	384.9	30.5	463.0	561.8	1,532.2	99.7%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	403.2	0.0	0.0	19.9	423.1	100.0%
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1	61.5%
		Unrelated	0.0	228.9	0.0	675.0	234.0	1,137.9	38.5%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	1,434.0	1,803.0	0.0	0.0	989.8	4,226.8	22.3%
		Unrelated	1,819.8	6,622.8	457.0	1,368.0	4,421.0	14,688.6	77.7%

Wind Project Developer and Transmission Owner Relationships

Table 12-50 shows the relationship between the project developer and transmission owner for all wind project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and project status. Of the 10,900.2 wind project MW that are in service or currently under construction, 12.0 MW (0.1 percent) have been developed by transmission owners building in their own service territory. DOM is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 10,741.2 MW that entered the queue in the DOM Zone during the time period of January 1, 1997, through September 30, 2022, 2,786.0 MW (25.9 percent) have been submitted by DOM or one of their affiliated companies.

Table 12-50 Relationship between project developer and transmission owner for all wind project MW in the queue: September 30, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,523.0	3,544.6	0.0	0.0	24,113.4	31,180.9	100.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	2,080.0	2,080.0	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DOM	DOM	Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	25.9%
		Unrelated	2,778.8	208.0	0.0	0.0	4,968.4	7,955.2	74.1%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	150.3	150.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,441.6	7.5	0.0	0.0	4,648.6	8,097.7	100.0%
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	9,283.2	4,302.1	200.0	0.0	26,270.4	40,055.7	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7,369.5	0.0	0.0	0.0	3,270.8	10,640.3	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	959.1	1,332.0	0.0	0.0	3,671.6	5,962.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	297.7	0.0	0.0	0.0	1,814.0	2,111.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	10,372.5	0.0	0.0	0.0	7,397.0	17,769.5	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	503.7	1,067.5	0.0	0.0	5,500.3	7,071.6	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	174.8	226.5	0.0	0.0	3,721.2	4,122.5	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,300.0	0.0	0.0	0.0	20.0	1,320.0	100.0%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	2.0%
		Unrelated	40,003.8	10,688.2	200.0	0.0	87,625.9	138,517.9	98.0%

Solar Project Developer and Transmission Owner Relationships

Table 12-51 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and project status. Of the 7,757.2 solar project MW that are in service or currently under construction, 1,525.8 MW (19.7 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 872.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through September 30, 2022, 175.4 MW (20.1 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-51 Relationship between project developer and transmission owner for all solar project MW in the queue: September 30, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	34.7	0.0	0.0	165.0	299.7	0.6%
		Unrelated	42,900.9	430.0	544.0	97.9	9,321.4	53,294.2	99.4%
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5	0.4%
		Unrelated	2,980.4	2.5	400.0	178.0	2,323.1	5,883.9	99.6%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	71.8	0.0	17.1	0.0	33.0	121.9	100.0%
DOM	DOM	Related	4,338.0	1,198.6	141.6	99.9	251.9	6,030.0	11.7%
		Unrelated	24,919.7	1,280.1	1,651.6	776.9	16,729.2	45,357.5	88.3%
DUKE	DUKE	Related	49.0	0.0	0.0	0.0	56.4	105.4	6.7%
		Unrelated	549.9	200.0	0.0	80.0	633.0	1,462.9	93.3%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,006.0	0.0	50.0	100.0	998.9	7,154.9	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3	0.3%
		Unrelated	665.7	65.0	2.6	0.0	2,284.4	3,017.7	99.7%
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0	7.2%
		Unrelated	154.9	1.1	0.0	0.0	101.6	257.6	92.8%
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0	0.1%
		Unrelated	13,534.2	0.0	100.0	32.5	3,516.2	17,182.9	99.9%
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4	0.1%
		Unrelated	1,876.1	143.0	231.6	294.0	2,666.5	5,211.2	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	145.4	3.3	0.0	0.0	98.2	246.9	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	212.6	2.5	27.5	0.0	441.6	684.3	100.0%
First Energy	APS	Related	71.2	0.0	0.0	0.0	0.0	71.2	0.7%
		Unrelated	6,083.3	140.5	80.0	314.7	2,823.5	9,441.9	99.3%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,514.2	0.0	180.0	375.0	2,136.7	9,205.9	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0	0.5%
		Unrelated	427.7	412.2	19.8	18.6	1,635.4	2,513.7	99.5%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	789.4	0.0	60.0	12.0	1,026.7	1,888.1	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,210.8	13.5	20.0	60.2	2,684.2	8,988.7	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	430.0	0.0	0.0	0.0	78.0	508.0	100.0%
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8	3.4%
		Unrelated	2,401.2	25.0	0.0	42.8	1,025.1	3,494.1	96.6%
PSEG	PSEG	Related	0.0	129.3	5.2	0.0	40.9	175.4	20.1%
		Unrelated	37.9	112.6	16.1	0.0	530.7	697.3	79.9%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	4,682.9	1,379.0	146.8	99.9	576.0	6,884.5	3.8%
		Unrelated	116,912.1	2,831.2	3,400.2	2,382.5	51,087.3	176,613.4	96.2%

Battery Project Developer and Transmission Owner Relationships

Table 12-52 shows the relationship between the project developer and transmission owner for all battery project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and project status. Of the 303.3 battery project MW that are in service or currently under construction, 60.0 MW (19.8 percent) have been developed by transmission owners building in their own service territory. PECO is the transmission owner with the highest percentage of affiliates building battery projects in their own service territory. Of the 65.3 MW that entered the queue in the PECO Zone during the time period of January 1, 1997, through September 30, 2022, 40.0 MW (61.3 percent) have been submitted by PECO or one of their affiliated companies.

Table 12-52 Relationship between project developer and transmission owner for all battery project MW in the queue: September 30, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	6.0	0.0	0.0	10.0	116.0	0.9%
		Unrelated	10,885.9	4.0	0.0	0.0	1,711.2	12,601.1	99.1%
AES	DAY	Related	0.0	20.0	0.0	0.0	0.0	20.0	2.6%
		Unrelated	340.0	0.0	0.0	0.0	414.9	754.9	97.4%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	205.0	0.0	0.0	0.0	20.0	225.0	100.0%
DOM	DOM	Related	1,076.7	0.0	20.0	0.0	0.0	1,096.7	6.6%
		Unrelated	14,041.5	0.0	0.0	0.0	1,531.4	15,572.9	93.4%
DUKE	DUKE	Related	0.0	14.0	0.0	0.0	23.3	37.3	9.5%
		Unrelated	277.2	6.0	0.0	0.0	72.2	355.4	90.5%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	176.0	0.0	0.0	0.0	20.3	196.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,739.5	0.0	0.0	0.0	181.0	1,920.5	100.0%
	BGE	Related	2.5	0.0	0.0	0.0	20.0	22.5	1.5%
		Unrelated	1,196.0	0.0	0.0	0.0	240.6	1,436.6	98.5%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7,376.1	87.0	0.0	0.0	1,104.0	8,567.1	100.0%
	DPL	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	1,063.0	0.0	0.0	0.0	364.0	1,427.0	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	40.0	40.0	61.3%
		Unrelated	0.0	1.0	0.0	0.0	24.3	25.3	38.7%
	PEPCO	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	795.0	0.0	0.0	0.0	20.0	815.0	99.9%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,944.8	39.9	0.0	0.0	356.0	3,340.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,218.0	0.0	0.0	0.0	226.4	2,444.4	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	790.8	40.0	14.0	2.0	859.2	1,706.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	955.2	0.0	0.0	0.0	244.7	1,199.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	997.8	28.4	0.0	0.0	401.0	1,427.2	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	475.0	20.0	0.0	20.0	309.8	824.8	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,775.0	3.0	0.0	7.0	9.5	1,794.5	100.0%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	1,181.2	40.0	20.0	0.0	93.3	1,334.5	2.3%
		Unrelated	48,251.8	229.3	14.0	29.0	8,110.6	56,634.7	97.7%

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-53 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2022, by transmission owner and project status. Of the 6.8 renewable hybrid project MW that are in service or currently under construction, 3.7 MW (53.9 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building hybrid projects in their own service territory. Of the 59.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through September 30, 2022, 3.7 MW (6.2 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-53 Relationship between project developer and transmission owner for all hybrid project MW in the queue: September 30, 2022

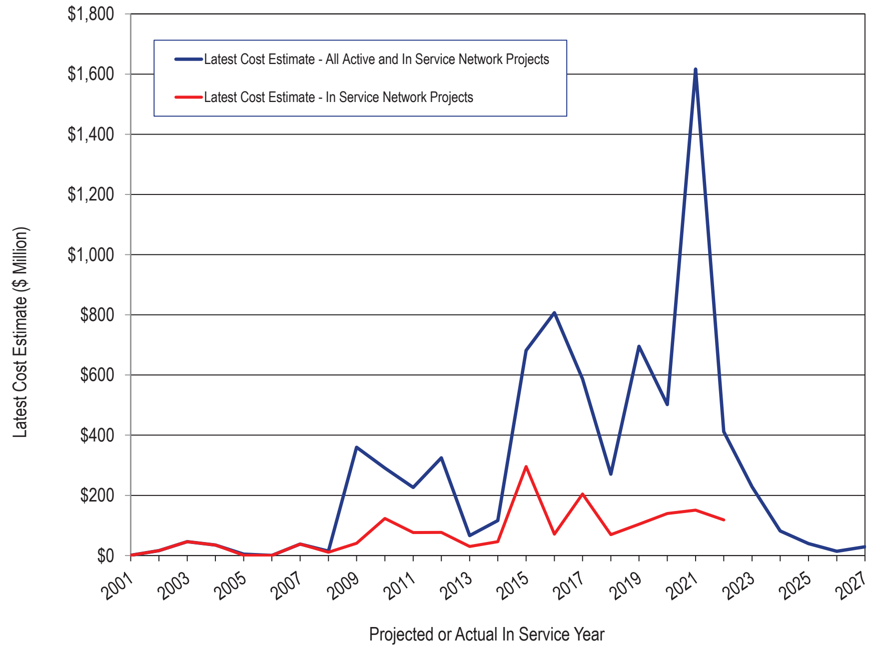
			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	180.0	0.0	0.0	0.0	0.0	180.0	0.9%
		Unrelated	15,455.6	0.0	3.2	0.0	3,460.8	18,919.6	99.1%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	500.9	0.0	0.0	0.0	0.0	500.9	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	107.5	0.0	0.0	0.0	0.0	107.5	100.0%
DOM	DOM	Related	17.0	0.0	0.0	0.0	0.0	17.0	0.2%
		Unrelated	7,316.8	0.0	0.0	0.0	2,289.9	9,606.7	99.8%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	50.0	0.0	0.0	0.0	0.0	50.0	100.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,094.1	0.0	0.0	0.0	1,004.0	4,098.1	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	221.0	0.0	0.0	0.0	14.5	235.5	100.0%
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,730.5	0.0	0.0	0.0	986.9	3,717.4	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	270.0	0.0	0.0	0.0	104.5	374.5	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	5.0	0.0	0.0	0.0	0.0	5.0	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,452.0	0.0	0.0	0.0	20.0	1,472.0	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,515.7	0.0	0.0	48.8	568.0	3,132.6	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	891.6	0.0	0.0	0.0	334.9	1,226.5	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	235.0	0.0	0.0	0.0	0.0	235.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	143.2	0.0	0.0	18.9	23.7	185.8	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,408.8	0.0	0.0	3.0	184.2	1,596.1	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	178.5	0.0	0.0	0.0	0.0	178.5	100.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	691.0	0.0	0.0	140.0	201.0	1,032.0	100.0%
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7	6.2%
		Unrelated	20.0	0.0	0.0	0.0	36.1	56.1	93.8%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	197.0	1.1	2.6	0.0	0.0	200.7	0.4%
		Unrelated	37,287.2	0.0	3.2	210.7	9,228.5	46,729.5	99.6%

Network Transmission Project Costs

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[58] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. In the study stage of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Transmission modifications necessary to maintain the reliability of the transmission system as a result of a new service request are identified in the facility study report. These identified modifications are known as network upgrades. While not all projects in the queue will require network upgrades to interconnect to the transmission system, the number of planned network transmission upgrades is strongly correlated with the number of active projects in the queue. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required.

Figure 12-5 shows the latest network transmission project cost estimates by projected or actual in service year for network projects in the status of active or in service, and for those projects already in service. The large amount of network upgrade costs in recent years is attributed to the large number of requests in the new services queue. However, as generation requests withdraw from the queue, the overall network costs decrease. Figure 12-5 also shows that there were a large number of network project costs projected based on resources expected to go in service in recent years. The projected in service dates for network projects are only updated periodically, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. PJM does not track final project costs, so the in service costs only reflect the last estimate provided by PJM before the project went in service.

Figure 12-5 Cost estimates of network projects by projected or actual in service year: January 1, 2001 through December 31, 2027



58 See OATT Parts IV & VI.

Regional Transmission Expansion Plan (RTEP)[59]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Manager approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects based on production cost analyses.[60] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants that are hired to assist in the review. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the cost/benefit ratio for the project. The cost/benefit ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrently with the long-term proposal window for reliability projects.

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term

59 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

60 See PJM. "*PJM Regional Transmission Expansion Plan: 2019*," (February 29, 2020) <https://www.pjm.com/-/media/library/reports-notices/2019-rtep/2019-rtep-book-1.ashx>.

window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[61]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The sixth market efficiency cycle is currently being performed for the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window is scheduled to open in January 2023. PJM is currently developing the market efficiency base case.

The Cost/Benefit Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a cost/benefit ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system

61 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates.

energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade and the value of the ARRs are assumed to match the forecasted CLMP differences on the ARR paths.

The Reliability Pricing Model (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional cost/benefit threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

There are significant issues with PJM's cost/benefit analysis. The current rules governing cost/benefit analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used. The current rules explicitly ignore the increased zonal load costs that a project may create. The current rules do not account for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that do not exceed the forecasted costs.

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's cost/benefit analysis. PJM's cost/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon will exaggerate the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established.

Without clear rules on how to allocate operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

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

The Transource Project

The Transource Project (Project 9A) is an example of a PJM approved market efficiency project that initially passed PJM's 1.25 cost/benefit threshold test despite having benefits, if accurately calculated, that were less than forecasted costs. This project also illustrates the risks of ignoring potential cost increases given that the costs included in the cost/benefit calculation are nonbinding estimates. The Transource Project was proposed in PJM's 2014/2015 RTEP long term window. PJM's 2014/2015 RTEP long term window was the first market efficiency cycle under Order 1000. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. The AP South Interface was one of the 12 identified flow gates listed in the 2014/15 RTEP Long Term Proposal Window Problem Statement.

A total of 41 market efficiency projects were proposed to address congestion on the AP South Transmission Interface. Transource Energy LLC, together with Dominion High Voltage, submitted a proposal referenced by PJM as Project 9A (or IEC or the Transource project) to address AP South related congestion.

Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the cost/benefit ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis.

The initial study had a benefit to cost ratio of 2.48, with a capital cost of $340.6 million. The sum of the positive (energy cost reductions) effects was $1,188.07 million. The sum of negative effects (energy cost increases) was $851.67 million. The net actual benefit of the project in the study was therefore $336.40 million, not the $1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.

Subsequent studies of the 9A project have reduced its benefit/cost ratio as a result of increased costs, decreased congestion on the AP South Interface since 2014 and a reduction in peak load forecasts since 2015.

PJM's 2019 study using simulations for years 2017, 2021, 2024 and 2027 had a cost benefit ratio of 2.10 with a capital cost of $383.63 million. The sum of the positive (energy cost reductions) effects was $855.19 million, a reduction of $322 million (28.0 percent) from the initial study. The sum of negative effects (energy cost increases) was $827.34 million, a reduction of $27.86 million (3.3 percent) from the results of the initial study. The net actual benefit of the project in the 2019 study was $27.85 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was 0.07, not 2.10. The project should have been rejected on those grounds.

A portion of Project 9A in Pennsylvania was challenged in a proceeding at the Pennsylvania PUC. On May 20, 2021, the Pennsylvania PUC denied the Transource application to build in Pennsylvania based on failure to demonstrate need combined with negative economic and environmental effects.[62] Transource is appealing the decision at the state and federal level.[63]

62 See *Applications of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection–East and West Projects in portions of York and Franklin Counties, Pennsylvania et al.*, Pennsylvania Public Utility Commission, Opinion and Order, Docket No. A-2017-2640195 et al. (May 20, 2021).

63 See *Transource Pennsylvania, LLC et al. v. Pennsylvania Public Utility Commission*, Docket No. 689 CD 2021 (Commonwealth of Pennsylvania Court); *Transource Pennsylvania LLC v. Gladys Brown Dutrieuille, et al.*, Docket No. 21-2567 (USDC M.D. Pa.).

On September 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the Transource IEC (9A) Project, based on the rejection by the Pennsylvania PUC. Project 9A was removed from PJM's planning models pending future updates.[64] At the time of the suspension, $131.9 million in material, engineering, land rights and project support costs had been incurred by developers, but there was no increase in transmission capability associated with the project.[65]

While suspended, PJM is required by Schedule 6 of the Operating Agreement (OA) to "annually review the cost and benefits" of Board approved market efficiency projects that have not commenced construction or have not received state siting approval. Under Schedule 6, PJM's 2021 study showed a cost/benefit ratio of 1.00 with a capital cost of $453.71 million. The sum of the positive (energy cost reductions) effects was $452.4 million, a reduction of $735.7 million (-61.9 percent) from the initial study. The sum of negative effects (energy cost increases) was $452.4 million, a reduction of $399.3 million (46.9 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2021 study was -$159.8 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was -0.35, not 2.10. The project should be rejected on these grounds rather than simply suspended.

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. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[66] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM makes use of the cost/benefit analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle.

PJM and MISO are currently performing an analysis to determine if an IMEP study will be required for the 2022/2023 IMEP cycle.

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. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion cost

64 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 18 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

65 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 19 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

66 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

relief over a four year period, that exceed the expected installed capacity cost of the proposed project.[67] [68]

The benefit of a proposed TMEP project is calculated as the value of eliminating congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits received by that RTO.[69] The proportion of benefits is calculated using the average shadow price of the constraint times the dfax to affected downstream buses times MW of load at the buses, which is effectively the proportion of congestion paid by the RTO. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021. .The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[70] Two additional projects were eliminated after studies showed that congestion was not persistent.[71]

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through the ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments relative to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

Multi Driver Process

On September 12, 2014, PJM filed revisions to the tariff to include provisions allowing PJM to include multi driver projects in its regional transmission expansion plan.[72] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, PJM can develop a multi driver approach project by identifying a more efficient or cost effective solution. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project. The incremental method expands or enhances a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.[73] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[74]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022.

67 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

68 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).

69 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

70 See "Interregional Planning Update," presented at the August 9, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220809/item-01---interregional-planning-update.ashx>.

71 See "Interregional Planning Update," presented at the October 4, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/item-01----interregional-planning-update.ashx>.

72 See PJM. Docket No. ER14-2864 (September 12, 2014).

73 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

74 150 FERC ¶ 61,117 (February 20, 2015).

PJM received 14 proposals from three entities. The identified facilities are market to market facilities, so PJM will coordinate with MISO when evaluating proposals.

Supplemental Transmission Projects

Supplemental projects are asserted to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[75] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

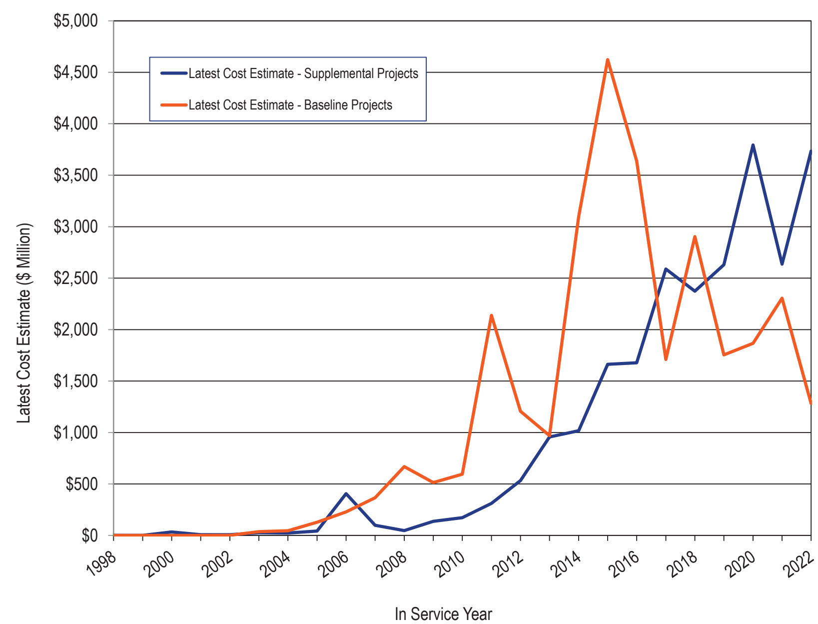
The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[76] Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-6 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-6, Table 12-54 and Table 12-55 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2022



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

76 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).

Table 12-54 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 860.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 192 for years 2008 through 2022 (post Order No. 890). As of September 30, 2022, there are 1,670 supplemental projects with expected in service dates within the next five years.

Table 12-54 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	ACEC	AEP	AMP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	0	2	0	40
2005	4	2	0	8	0	0	4	0	0	0	1	14	0	1	0	0	0	1	2	0	0	2	0	39
2006	4	2	0	5	0	0	6	0	0	0	0	9	0	1	0	0	0	0	1	0	2	1	0	31
2007	1	1	0	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	0	3	1	0	41
2009	3	1	0	6	0	1	8	0	0	3	3	5	0	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	0	7	0	3	4	0	0	6	3	0	0	1	2	0	0	2	0	0	3	5	0	42
2011	0	8	0	8	0	0	2	0	0	5	2	0	0	1	0	0	0	4	0	0	6	4	0	40
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	5	11	0	64
2013	5	21	0	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	0	2	8	2	14	0	5	6	18	3	3	2	0	0	0	1	2	0	9	16	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	24	0	143
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	30	0	147
2017	8	107	0	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	0	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	26	0	288
2019	3	158	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	354
2020	5	125	0	4	33	6	12	5	13	1	30	2	6	10	17	0	0	3	35	1	17	22	0	347
2021	4	139	0	6	31	5	3	7	13	2	22	1	7	9	21	0	0	19	24	0	19	21	0	353
2022	2	237	0	9	39	2	9	6	7	1	36	1	6	10	47	0	0	6	36	0	17	18	0	489
2023	6	282	1	4	23	0	5	17	5	1	27	3	5	1	29	2	5	3	32	1	14	25	0	491
2024	5	165	0	0	11	2	4	11	2	0	18	6	3	14	29	0	0	0	45	4	15	10	0	344
2025	5	114	0	1	12	3	0	8	1	1	24	2	1	0	23	0	0	0	30	1	7	18	0	251
2026	5	19	0	0	8	7	1	0	3	0	19	2	2	1	5	0	0	0	2	0	8	13	0	95
2027	1	27	0	0	4	1	0	0	2	2	1	1	1	0	1	0	0	0	0	0	5	0	0	46
2028	0	16	0	0	0	0	0	0	2	1	1	1	2	0	0	0	0	0	1	0	11	0	0	35
2029	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	2	0	15	0	0	20
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2031	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14	0	0	15
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	94	1,641	1	116	274	49	225	56	113	59	357	157	55	61	194	2	5	53	237	17	269	346	0	4,381

Table 12-55 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 2,450.1 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1.6 billion for years 2008 through 2022 (post Order No. 890). As of September 30, 2022, the 1,670 supplemental projects with expected in service dates within the next five years, have a total cost estimate of $17.7 billion.

Table 12-55 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	ACEC	AEP	AMP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.67	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.93
2006	$4.03	$309.70	$0.00	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.82
2008	$2.36	$0.00	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.67
2010	$0.00	$34.36	$0.00	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.71	$0.00	$1,017.27
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.02
2016	$74.54	$84.13	$0.00	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,677.44
2017	$66.28	$648.74	$0.00	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$816.23	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$631.25	$0.00	$2,372.39
2019	$64.30	$1,162.13	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,629.60
2020	$59.58	$782.64	$0.00	$0.30	$112.78	$62.58	$78.09	$13.66	$72.06	$6.40	$258.72	$39.50	$25.61	$2.60	$23.10	$0.00	$0.00	$2.40	$74.50	$102.70	$215.29	$1,861.58	$0.00	$3,794.09
2021	$86.54	$1,032.66	$0.00	$9.50	$184.21	$26.65	$125.70	$26.10	$117.39	$18.90	$98.40	$0.58	$24.34	$41.30	$82.99	$0.00	$0.00	$45.30	$63.48	$0.00	$197.67	$454.44	$0.00	$2,636.15
2022	$106.40	$1,580.08	$0.00	$11.12	$265.16	$187.70	$123.10	$23.15	$100.79	$45.00	$227.48	$8.80	$27.03	$28.10	$142.68	$0.00	$0.00	$90.90	$52.31	$0.00	$195.87	$519.63	$0.00	$3,735.30
2023	$118.45	$2,087.89	$14.05	$14.14	$165.43	$0.00	$30.60	$62.45	$45.56	$0.00	$175.61	$66.60	$36.61	$0.00	$182.36	$63.40	$4.40	$201.80	$109.60	$3.60	$208.53	$835.29	$0.00	$4,426.37
2024	$81.81	$1,409.16	$0.00	$0.00	$145.93	$118.00	$215.80	$78.70	$17.64	$0.00	$393.67	$87.80	$31.33	$103.90	$129.76	$0.00	$0.00	$0.00	$78.00	$809.47	$346.80	$312.31	$0.00	$4,360.08
2025	$83.19	$990.29	$0.00	$60.00	$284.80	$144.10	$0.00	$45.85	$7.90	$34.00	$322.67	$51.40	$1.05	$0.00	$136.30	$0.00	$0.00	$0.00	$72.10	$0.50	$208.20	$426.33	$0.00	$2,868.68
2026	$95.50	$201.10	$0.00	$0.00	$116.50	$687.25	$67.00	$0.00	$19.80	$0.00	$366.40	$58.78	$21.90	$16.00	$33.30	$0.00	$0.00	$0.00	$41.10	$0.00	$239.00	$358.80	$0.00	$2,322.43
2027	$17.13	$380.03	$0.00	$0.00	$404.00	$0.00	$0.00	$0.00	$30.62	$160.00	$35.00	$6.10	$13.74	$0.00	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$96.90	$0.00	$0.00	$1,153.52
2028	$0.00	$365.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$29.57	$30.40	$0.00	$15.00	$30.78	$0.00	$0.00	$0.00	$0.00	$0.00	$138.00	$0.00	$181.49	$0.00	$0.00	$790.68
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$276.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$200.00	$0.00	$221.97	$0.00	$0.00	$697.97
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$193.75	$0.00	$0.00	$193.75
2031	$0.00	$0.00	$0.00	$0.00	$80.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$335.00	$0.00	$0.00	$415.00
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$5.40	$0.00	$0.00	$5.40
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$958.83	$12,745.19	$14.05	$241.21	$2,453.11	$1,670.36	$1,861.83	$250.21	$733.80	$548.35	$2,785.67	$684.17	$251.33	$212.55	$828.54	$63.40	$4.40	$752.30	$928.72	$1,136.97	$3,664.77	$9,360.49	$0.00	$42,150.25

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[77]

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.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion.** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[78] On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[79] Some supplemental projects are in this category. In a decision issued August 19, 2022, the U.S. Court of Appeals for the D.C Circuit found that FERC reasonably approved MISO's Immediate Need Reliability Exception.[80] The Court rejected arguments challenging the MISO rule because (i) the definition of projects eligible for the exception was insufficiently limited and (ii) the rule allows for designating the incumbent developer before posting of the basis for the exception.[81] The decision was largely based on deference to FERC expertise.[82]
- **Below 200kV.** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[83] Some supplemental projects are in this category.
- **Substation Equipment.** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[84] Some supplemental projects are in this category.

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

Dominion Data Center Alley Immediate Need

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth due to increases in customer requests for data centers in the area. As a result, Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM has identified the need for additional baseline reinforcements to support the load growth. "Due to the pace and magnitude of load increase in the data center alley area, current operational

77 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).
78 See OA Schedule 6 § 1.5.8(m).
79 169 FERC ¶ 61,054 (2019).
80 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
81 *Id.* at 999.
82 *Id.*
83 See OA Schedule 6 § 1.5.8(n).
84 See OA Schedule 6 § 1.5.8(p).

and reliability constraints on the transmission system to serve load and consideration that a shortened competitive window will lead to delays of about 6 months, PJM has determined to designate Dominion construction responsibility to mitigate these immediate need violations."[85] [86] The proposed solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work. The initial cost estimate for the scope of work is $627.6 million.[87]

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[88]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[89] The existing proposal templates do not provide enough information to adequately perform a financial analysis. 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.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.[90]

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost-of-service recovery through AEP's formula rates.[91] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[92]

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

85 See "Dominion Northern Virginia Area Violations," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx>.
86 See "Dominion Northern Virginia Area Immediate Need," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia---immediate-need.ashx>.
87 See "Reliability Analysis Update Immediate Need," presented at the September 6, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/item-09a---reliability-analysis-update---immediate-need.ashx>.
88 170 FERC ¶ 61,243 (2020).
89 See "PJM Manual 14F: Competitive Planning Process," Rev. 9 (April 27, 2022).
90 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement*," <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.
91 See *AEP*, Docket No. EL20-58 (July 22, 2020).
92 173 FERC ¶ 61,264 (2020).

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, 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.[93]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In the first nine months of 2022, the PJM Board approved a net change of $597.5 million in transmission upgrades. As of September 30, 2022, the PJM Board had approved $39.5 billion in transmission system enhancements since 1999. On February 18, 2022, the PJM Board authorized an additional $515.4 million in transmission upgrades and additions. On July 12, 2022, the PJM Board authorized an additional $82.1 million in transmission upgrades and additions.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2022, no QTUs have cleared a BRA or IA.

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

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of “whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects.”[94] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[95]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[96] The Commission found that PJM’s solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable. An appeal of this case currently is pending at the U.S. Court of Appeals for the D.C. Circuit.[97]

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The MMU

94 153 FERC ¶ 61,245 at P 35 (2015).
95 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
96 170 FERC ¶ 61,122 (2020).
97 See *New York Power Authority, et al v. FERC*, 20-1074.

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.

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. These include direct impacts on energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were $825.1 million for one month.[98]

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019. The default transmission penalty factor is $2,000 per MWh.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the limits.[99] Violation of these reduced line ratings results in penalty factors setting prices. In 2021, there were 170,067 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit. In 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 8.8 times higher than when the transmission constraint was binding at its limit.[100]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity

98 See the *2018 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses.
99 See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018 meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.
100 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: Energy Market.

requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[101]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[102] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings.

In PJM, transmission owners have substantial discretion in the approach to line ratings.[103]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Over defining line ratings results in less reliability than planned for. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to

101 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
102 See "PJM Manual 3: Transmission Operations," Rev. 62 (June 1, 2022) § 2.1.1, at p 27.
103 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[104] The line rating methods should be public and fully transparent.

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.[105] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission recently adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient-adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings; transmission owners share transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; transmission providers maintain a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website.[106] [107]

On rehearing, the Commission provided clarification of market monitors' ability to take action based on information received about transmission line ratings: "We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO."[108]

Order No. 881 enhances transparency of information on line ratings and how they are determined. Requiring ambient and hourly adjustments constitutes substantive improvement. Continued reform consistent with the MMU's recommendations is needed in order to ensure consistent and accurate transmission line ratings in PJM.

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[109] But on February 17, 2022, in Docket No. AD22-5, FERC issued a notice of inquiry addressing the DLR issues.[110]

Dynamic Line Ratings (DLR) and Grid Enhancing Technology (GETs)

For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real time prices are based on actual current line ratings. The relevant real-time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology (DLR) and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

104 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
105 *See* the *2018 State of the Market Report for PJM*, Volume II, Section 2: Recommendations.
106 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
107 *See* 18 CFR § 35.28(c)(5)&(g)(13).
108 Order No. 881-A at P 91.
109 Order No. 881 at PP 25, 254
110 *Implementation of Dynamic Line Ratings*, Notice of Inquiry, 178 FERC ¶ 61,110 (2022).

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[111] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[112] The specific timeline is shown in Table 12-57.[113]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2021/2022 planning period and the first four months of 2022/2023 planning period, regardless of when they were initially submitted.[114] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through September 2022.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[115] Table 12-56 shows that 73.8 percent of 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 in the first four months of 2022/2023 planning period. Table 12-56 also shows that 77.3 percent of the requested outages were planned for less than or equal to five days and 8.0 percent of requested outages were planned for greater than 30 days in the 2021/2022 planning period.

111 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM, "Manual 3: Transmission Operations," Rev. 62 (June 1, 2022).
112 See PJM, "Manual 3: Transmission Operations," Rev. 62 (June 1, 2022).
113 See PJM, "Manual 3: Transmission Operations," Rev. 62 (June 1, 2022).
114 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
115 *Id.* at 70.

Table 12-56 Transmission facility outage request summary by planned duration: June 2021 through September 2022

	2021/2022 (12 months)		2022/2023 (4 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,187	77.3%	4,541	73.8%
>5 & <=30	2,872	14.6%	808	13.1%
>30	1,578	8.0%	806	13.1%
Total	19,637	100.0%	6,155	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-57.[116]

The purpose of the rules defined in Table 12-57 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[117]

Table 12-57 Transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	The earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

116 See PJM, "Manual 3: Transmission Operations," Rev. 62 (June 1, 2022).
117 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).

Table 12-58 shows a summary of requests by received status. In the first four months of 2022/2023 planning period, 42.0 percent of outage requests received were late. In the 2021/2022 planning period, 40.1 percent of outage requests received were late.

Table 12-58 Transmission facility outage requests by received status: June 2021 through September 2022

	2021/2022 (12 months)				2022/2023 (4 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,607	5,580	15,187	36.7%	2,819	1,722	4,541	37.9%
>5 & <=30	1,557	1,315	2,872	45.8%	405	403	808	49.9%
>30	600	978	1,578	62.0%	344	462	806	57.3%
Total	11,764	7,873	19,637	40.1%	3,568	2,587	6,155	42.0%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[118]

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[119] Table 12-59 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in first four months of 2022/2023 planning period, 14.6 percent were for emergency outages. Of all outage requests scheduled to occur in the 2021/2022 planning period, 12.1 percent were for emergency outages.

118 See PJM, "Manual 3: Transmission Operations," Rev. 62 (June 2, 2022). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

119 PJM, "Manual 3: Transmission Operations," Rev. 62 (June 1, 2022).

Table 12-59 Transmission facility outage requests by emergency: June 2021 through September 2022

	2021/2022 (12 months)				2022/2023 (4 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,749	13,438	15,187	11.5%	635	3,906	4,541	14.0%
>5 & <=30	357	2,515	2,872	12.4%	130	678	808	16.1%
>30	267	1,311	1,578	16.9%	136	670	806	16.9%
Total	2,373	17,264	19,637	12.1%	901	5,254	6,155	14.6%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[120]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-60 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first four months of 2022/2023 planning period, 9.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 8.7 percent (51 out of 586) were denied by PJM in the first four months of 2022/2023 planning period and 19.6 percent (115 out of 586) were cancelled (Table 12-62). Of all outage requests submitted to occur in the 2021/2022 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period and 19.6 percent (242 out of 1,236) were cancelled (Table 12-62).

120 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 15 (Jan. 26, 2022).

Table 12-60 Transmission facility outage requests by congestion: June 2021 through September 2022

	2021/2022 (12 months)				2022/2023 (4 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	918	14,269	15,187	6.0%	441	4,100	4,541	9.7%
>5 & <=30	211	2,661	2,872	7.3%	94	714	808	11.6%
>30	107	1,471	1,578	6.8%	51	755	806	6.3%
Total	1,236	18,401	19,637	6.3%	586	5,569	6,155	9.5%

Table 12-61 shows the outage requests summary by received status, congestion status and emergency status. In the first four months of 2022/2023 planning period, 27.7 percent of requests were submitted late and were nonemergency while 1.3 percent of requests (78 out of 6,155) were late, nonemergency, and expected to cause congestion. In the 2021/2022 planning period, 28.3 percent of request were submitted late and were nonemergency while 1.1 percent of requests (221 out of 19,637) were late, nonemergency, and expected to cause congestion.

Table 12-61 Transmission facility outage requests by received status, emergency and congestion: June 2021 through September 2022

		2021/2022 (12 months)				2022/2023 (4 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	56	2,261	2,317	11.8%	32	852	884	14.4%
	Non Emergency	221	5,335	5,556	28.3%	78	1,625	1,703	27.7%
On Time	Emergency	8	48	56	0.3%	4	13	17	0.3%
	Non Emergency	951	10,757	11,708	59.6%	472	3,079	3,551	57.7%
Total		1,236	18,401	19,637	100.0%	586	5,569	6,155	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[121] Table 12-62 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-62. Table 12-62 shows that of all the outage requests that were expected to cause congestion, 8.7 percent (51 out of 586) were denied by PJM in the first four months of 2022/2023 planning period, 54.3 percent were complete and 19,6 percent (115 out of 586) were cancelled. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period, 67.6 percent were complete and 19.6 percent (242 out of 1,236) were cancelled.

121 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).

Table 12-62 Transmission facility outage requests by processed status: June 2021 through September 2022

Received Status		2021/2022 (12 months) Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	2022/2023 (4 months) Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	7	47	0	1	56	83.9%	1	31	0	0	32	96.9%
	Non Emergency	36	159	3	22	221	71.9%	8	53	8	7	78	67.9%
On Time	Emergency	2	6	0	0	8	75.0%	0	4	0	0	4	100.0%
	Non Emergency	197	624	93	24	951	65.6%	106	230	83	44	472	48.7%
Total		242	836	96	47	1,236	67.6%	115	318	91	51	586	54.3%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[122] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-62 shows that in the 2021/2022 planning period, 221 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

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. It is not clear that PJM's analysis of expected congestion identified or highlighted the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion. After high congestion costs of Greys Point - Harmony Village constraint and market participant manipulative behavior caused by the outage were identified by the end of January, on February 11, 2022 Dominion decided to temporarily terminate the outage in March in order to work on upgrading Greys Point, Harmony Village and White Stone path. The Greys Point - Harmony Village Line has not been binding since March 14, 2022. It indicates that if the market impact of the outage was identified during PJM outage analysis process and action was taken because of the analysis result, the high congestion costs and manipulative behavior could have been prevented.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-63 is a summary of all the outage requests planned for the 2021/2022 planning period and the first four months of 2022/2023 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first four months of 2022/2023 planning period, 29.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2021/2022 planning period, 29.3 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

122 OA Schedule 1 § 1.9.2.

Table 12-63 Rescheduled and cancelled transmission outage requests: June 2021 through September 2022

	2021/2022 (12 months)					2022/2023 (4 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	15,187	3,144	20.7%	2,128	14.0%	4,541	1,020	22.5%	668	14.7%
>5 & <=30	2,872	1,534	53.4%	207	7.2%	808	418	51.7%	58	7.2%
>30	1,578	1,073	68.0%	88	5.6%	806	356	44.2%	22	2.7%
Total	19,637	5,751	29.3%	2,423	12.3%	6,155	1,794	29.1%	748	12.2%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[123] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[124] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

The MMU recommends that PJM reevaluate all transmission outage tickets as On Time or Late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-57) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-64 shows equipment outages by the equipment instead of by outage request.

Table 12-64 shows that there were 4,920 transmission equipment planned outages in the first four months of 2022/2023 planning period, of which 749 or 15.2 percent were longer than 30 days, and of which 27 or 0.5 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-64 Transmission equipment outages: June 2021 through September 2022

		2021/2022 (12 months)		2022/2023 (4 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,367	11.2%	722	14.7%
	Yes	238	2.0%	27	0.5%
<= 30		10,594	86.8%	4,171	84.8%
Total		12,199	100.0%	4,920	100.0%

123 PJM, "Manual 3: Transmission Operations," Rev. 62 (Jan. 26, 2022).
124 *Id.*

Table 12-65 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[125] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first four months of 2022/2023 planning period, within effective duration greater than a month and shorter than two months, there were 14 outages with a combined duration longer than 30 days.

Table 12-65 Transmission equipment outages by effective duration: June 2021 through September 2022

	2021/2022 (12 months)		2022/2023 (4 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.3%	1	3.7%
>31 & <=62	29	12.2%	14	51.9%
>62 & <=93	20	8.4%	4	14.8%
>93	186	78.2%	8	29.6%
Total	238	100.0%	27	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

125 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[126]

In the first four months of 2022/2023 planning period, 171 outage requests were included in the annual FTR market outage list and 5,984 outage requests were not included.[127] In the 2021/2022 planning period, 367 outage requests were included in the annual FTR market outage list and 19,270 outage requests were not included.Table 12-66, Table 12-67, Table 12-68 and Table 12-69 show the summary information on the modeled outage requests and Table 12-70 and Table 12-71 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-66 shows that 19.3 percent of the outage requests modeled in the Annual FTR Market for the first four months of 2022/2023 planning period had a planned duration of less than two weeks and that 16.4 percent of the outage requests (28 out of 171) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 27.0 percent of the outage requests modeled in the Annual FTR Market for the 2021/2022 planning period had a planned duration of less than two weeks and that 16.3 percent of the outage requests (60 out of 367) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

126 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

127 PJM's treatment of transmission outages in the FTR models is discussed in the *2022 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-66 Annual FTR market modeled transmission facility outage requests by received status: June 2021 through September 2022

	2021/2022 (12 months)				2022/2023 (4 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	86	13	99	27.0%	32	1	33	19.3%
>=2 weeks & <2 months	128	16	144	39.2%	40	5	45	26.3%
>=2 months	93	31	124	33.8%	71	22	93	54.4%
Total	307	60	367	100.0%	143	28	171	100.0%

Table 12-67 shows the annual FTR market modeled outage requests summary by emergency status and received status. Three of the annual FTR market modeled outages expected to occur in the first four months of 2022/2023 planning period were emergency outages. None of the modeled outages expected to occur in the 2021/2022 planning period were emergency outages.

Table 12-67 Annual FTR market modeled transmission facility outage requests by emergency: June 2021 through September 2022

		2021/2022 (12 months)				2022/2023 (4 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	86	86	100.0%	0	32	32	100.0%
	>=2 weeks & <2 months	0	128	128	100.0%	0	40	40	100.0%
	>=2 months	0	93	93	100.0%	0	71	71	100.0%
	Total	0	307	307	100.0%	0	143	143	100.0%
Late	<2 weeks	0	13	13	100.0%	1	0	1	0.0%
	>=2 weeks & <2 months	0	16	16	100.0%	0	5	5	100.0%
	>=2 months	0	31	31	100.0%	2	20	22	90.9%
	Total	0	60	60	100.0%	3	25	28	89.3%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-68 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first four months of 2022/2023 planning period and submitted late, 7.1 (2 out of 28) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2021/2022 planning period and submitted late, 20.0 percent (12 out of 60) were expected to cause congestion.

Table 12-68 Annual FTR market modeled transmission facility outage requests by congestion: June 2021 through September 2022

		2021/2022 (12 months)				2022/2023 (4 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	14	72	86	16.3%	10	22	32	31.3%
	>=2 weeks & <2 months	35	93	128	27.3%	8	32	40	20.0%
	>=2 months	18	75	93	19.4%	16	55	71	22.5%
	Total	67	240	307	21.8%	34	109	143	23.8%
Late	<2 weeks	2	11	13	15.4%	0	1	1	0.0%
	>=2 weeks & <2 months	6	10	16	37.5%	0	5	5	0.0%
	>=2 months	4	27	31	12.9%	2	20	22	9.1%
	Total	12	48	60	20.0%	2	26	28	7.1%

Table 12-69 shows that 17.8 percent of outage requests modeled in the annual FTR market for the first four months of 2022/2023 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 20.1 percent for the 2021/2022 planning period. Table 12-69 also shows that 15.1 percent of outages requests modeled in the Annual FTR Market for the first four months of 2022/2023 planning period and with a duration of two months or longer were cancelled, compared to 20.2 percent for the 2021/2022 planning period.

Table 12-69 Annual FTR market modeled transmission facility outage requests by processed status: June 2021 through September 2022

		2021/2022 (12 months)		2022/2023 (4 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	11	11.1%	3	9.1%
	Denied	1	1.0%	0	0.0%
	Approved	0	0.0%	1	3.0%
	Cancelled	27	27.3%	16	48.5%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	60	60.6%	13	39.4%
	Total	99	100.0%	33	100.0%
>=2 weeks & <2 months	In Progress	28	19.4%	8	17.8%
	Denied	1	0.7%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	29	20.1%	8	17.8%
	Revised	1	0.7%	1	2.2%
	Active	0	0.0%	7	15.6%
	Completed	85	59.0%	21	46.7%
	Total	144	100.0%	45	100.0%
>=2 months	In Progress	10	8.1%	21	22.6%
	Denied	0	0.0%	0	0.0%
	Approved	3	2.4%	1	1.1%
	Cancelled	25	20.2%	14	15.1%
	Revised	0	0.0%	0	0.0%
	Active	3	2.4%	43	46.2%
	Completed	83	66.9%	14	15.1%
	Total	124	100.0%	93	100.0%
Total Cancelled		81	22.1%	38	22.2%
Grand Total		367		171	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first four months of 2022/2023 planning period, 171 outage requests were modeled and 5,984 outage requests were not modeled in the Annual FTR Market. In the 2021/2022 planning period, 367 outage requests were modeled and 19,270 outage requests were not modeled in the Annual FTR Market.

Table 12-70 shows that 5.1 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date for the first four months of 2022/2023 planning period compared to 13.7 percent in the 2021/2022 planning period.

Table 12-70 Transmission facility outage requests not modeled in Annual FTR Auction: June 2021 through September 2022

	2021/2022 (12 months)						2022/2023 (4 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,929	8,361	81.3%	222	6,103	96.5%	1,159	1,811	61.0%	134	1,795	93.1%
>=2 weeks & <2 months	641	351	35.4%	129	796	86.1%	300	17	5.4%	87	223	71.9%
>=2 months	151	24	13.7%	191	372	66.1%	131	7	5.1%	202	118	36.9%
Total	2,721	8,736	76.3%	542	7,271	93.1%	1,590	1,835	53.6%	423	2,136	83.5%

Table 12-71 shows that 93.2 percent of late outage requests that were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date, and were active or completed in the first four months of 2022/2023 planning period. It also shows that 91.1 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were active or completed in the 2021/2022 planning period.

Table 12-71 Late transmission facility outage requests: June 2021 through September 2022

	2021/2022 (12 months)			2022/2023 (4 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,287	6,103	86.6%	1,554	1,795	86.6%
>=2 weeks & <2 months	697	796	87.6%	194	223	87.0%
>=2 months	339	372	91.1%	110	118	93.2%
Total	6,323	7,271	87.0%	1,858	2,136	87.0%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent those transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

Monthly FTR Market

When determining transmission outages to be modeled in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations less than or equal to five days. PJM exercises significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[128] Table 12-72 and Table 12-73 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-74 and Table 12-75 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-72 shows that on average, 31.3 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first four months of 2022/2023 planning period. On average, 33.1 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2021/2022 planning period.

Table 12-72 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2021 through September 2022

	2021/2022				2022/2023			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	209	116	325	35.7%	246	101	347	29.1%
Jul	103	85	188	45.2%	147	87	234	37.2%
Aug	125	81	206	39.3%	160	85	245	34.7%
Sep	363	147	510	28.8%	483	156	639	24.4%
Oct	480	192	672	28.6%				
Nov	454	205	659	31.1%				
Dec	325	153	478	32.0%				
Jan	214	118	332	35.5%				
Feb	216	121	337	35.9%				
Mar	399	142	541	26.2%				
Apr	454	172	626	27.5%				
May	402	182	584	31.2%				
Average	312	143	455	33.1%	259	107	366	31.3%

Table 12-73 shows that on average, 17.2 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first four months of 2022/2023 planning period. On average, 17.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2021/2022 planning period.

128 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-73 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2021 through September 2022

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2021/2022	Jun	35	2	10	55	0	76	147	325	16.9%
	Jul	15	2	4	26	0	76	65	188	13.8%
	Aug	24	1	4	25	0	86	66	206	12.1%
	Sep	56	2	15	89	0	176	172	510	17.5%
	Oct	56	7	21	120	0	216	252	672	17.9%
	Nov	47	3	15	108	0	182	304	659	16.4%
	Dec	32	2	8	82	0	95	259	478	17.2%
	Jan	41	1	19	61	0	96	114	332	18.4%
	Feb	43	1	17	54	0	105	117	337	16.0%
	Mar	64	2	15	109	0	157	194	541	20.1%
	Apr	55	2	20	117	0	163	269	626	18.7%
	May	60	8	25	106	0	122	263	584	18.2%
	Average	44	3	14	79	0	129	185	455	17.4%
2022/2023	Jun	27	16	14	57	0	78	155	347	16.4%
	Jul	20	9	7	40	0	81	77	234	17.1%
	Aug	19	7	10	37	0	81	91	245	15.1%
	Sep	65	6	24	130	1	210	203	639	20.3%
	Average	33	10	14	66	0	113	132	366	17.2%

Table 12-74 shows that on average, 13.5 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first four months of 2022/2023 planning period, compared to 9.1 percent in the 2021/2022 planning period. On average, 63.1 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first four months of 2022/2023 planning period, compared to 61.6 percent in the 2021/2022 planning period.

Table 12-74 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2021 through September 2022

	2021/2022						2022/2023					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	776	87	10.1%	323	613	65.5%	758	158	17.2%	313	557	64.0%
Jul	349	69	16.5%	272	501	64.8%	370	78	17.4%	247	465	65.3%
Aug	365	49	11.8%	262	464	63.9%	405	70	14.7%	279	466	62.6%
Sep	936	103	9.9%	318	615	65.9%	976	45	4.4%	327	503	60.6%
Oct	1,036	76	6.8%	385	663	63.3%						
Nov	860	50	5.5%	411	516	55.7%						
Dec	673	34	4.8%	341	524	60.6%						
Jan	567	81	12.5%	308	461	59.9%						
Feb	697	68	8.9%	348	530	60.4%						
Mar	1,292	75	5.5%	332	585	63.8%						
Apr	1,536	107	6.5%	385	531	58.0%						
May	1,199	136	10.2%	421	571	57.6%						
Average	857	78	9.1%	342	548	61.6%	627	88	13.5%	292	498	63.1%

Table 12-75 shows that on average, 72.6 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and completed in the first four months of 2022/2023 planning period, compared to 70.3 percent in the 2021/2022 planning period.

Table 12-75 Late transmission facility outage requests: June 2021 through September 2022

	2021/2022			2022/2023		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	419	613	68.4%	407	557	73.1%
Jul	371	501	74.1%	354	465	76.1%
Aug	307	464	66.2%	335	466	71.9%
Sep	408	615	66.3%	349	503	69.4%
Oct	470	663	70.9%			
Nov	347	516	67.2%			
Dec	402	524	76.7%			
Jan	301	461	65.3%			
Feb	370	530	69.8%			
Mar	407	585	69.6%			
Apr	383	531	72.1%			
May	439	571	76.9%			
Average	385	548	70.3%	361	498	72.6%

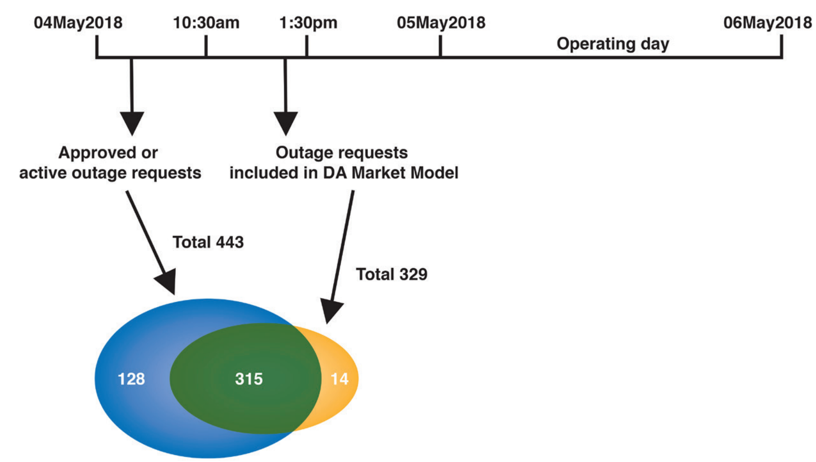
Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am.[129]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of May 5, 2018, Figure 12-7 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-7 Illustration of day-ahead market analysis: May 5, 2018



129 PJM, "Manual 3: Transmission Operations," Rev. 62 (June 1, 2022).

Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-8 Approved or active outage requests: January 2015 through September 2022

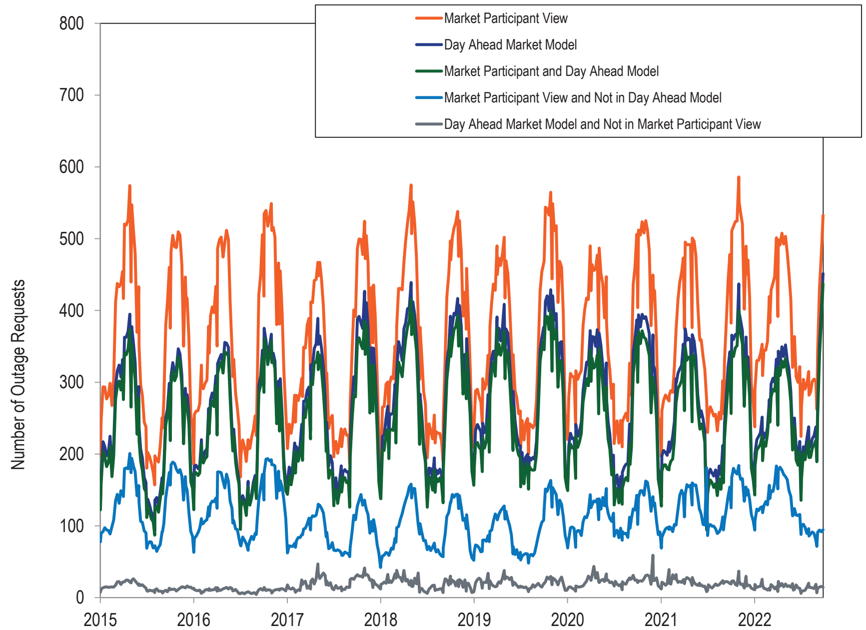


Figure 12-9 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-9 Day-ahead market model outages: January 2015 through September 2022

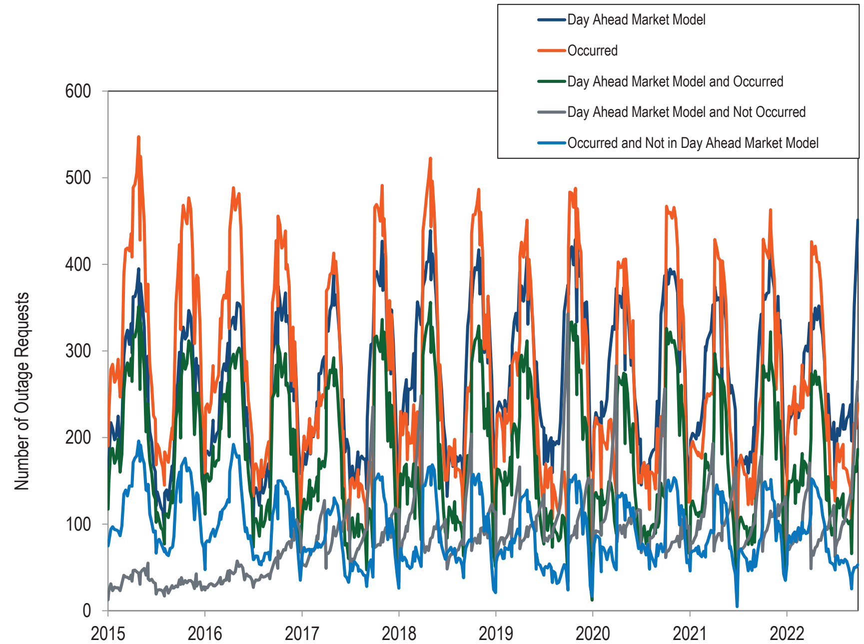


Figure 12-10 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-10 Approved or active outage requests: January 2015 through September 2022

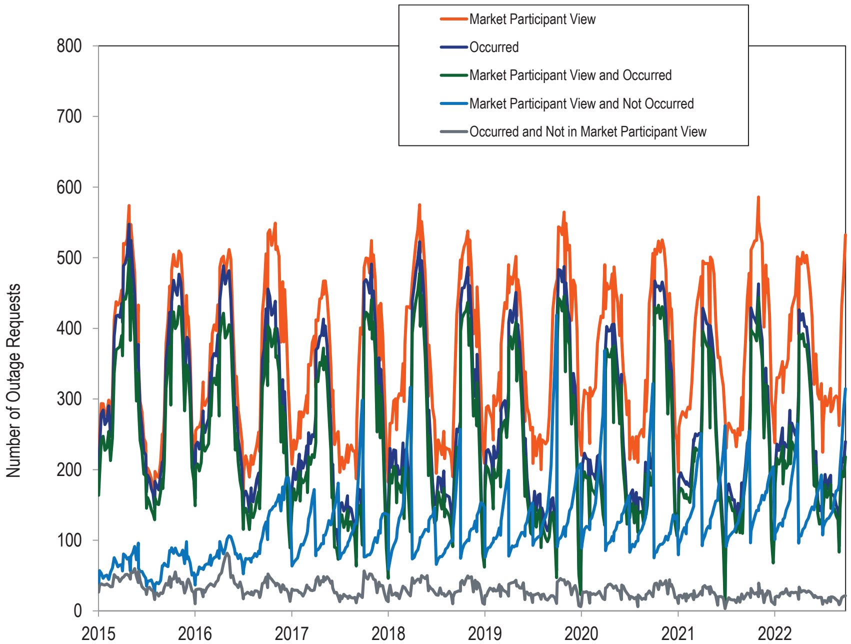


Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has added increasingly complex rules and regularly intervenes in the FTR mechanism as the PJM FTR design has moved further and further from these economic fundamentals. Some market participants have profited in various ways from these design flaws and those market participants now strongly defend the current design. The customers who ultimately pay congestion are generally not aware of the FTR design and do not understand the extent to which the design fails to offset their congestion payments.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the combined day-ahead and balancing (real-time) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. But most load was served by intrazonal generation. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. The flawed idea that congestion is based on contract paths was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load.

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP, but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing (real-time) congestion to load. Congestion, in PJM's two settlement market, is the sum of day-ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR design, the load still owns the rights to congestion revenue, but the ARR design allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR design, the right to all congestion revenues should belong to load. All congestion surplus should be assigned to load. But the actual implementation produces a very different result.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not and do not account for all congestion. The use of contract paths led to the mistaken conclusion that some congestion did not belong to load and could be sold to FTR buyers. The ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR payments are less than target allocations. So called surplus revenue is paid to FTR holders to ensure payment, despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. This

2 See *id.* at 62, 259–62,260 & n. 123.

divergence between actual network use and historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of generating units retired and new units were added.[3] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The product is defined as the difference in congestion prices across specific transmission contract paths. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues. The quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the fact that ARR holders cannot set the sale price for congestion revenue rights, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset 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 been underpaid by $3.8 billion from the 2011/2012 planning period through the first four months of the 2022/2023 planning period. The 31.5 percent share of congestion offset by ARRs and self-scheduled FTRs in the 2021/2022 planning period was the lowest offset to congestion since PJM implemented ARRs.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

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

3 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>.

if the distortions subsequently introduced into the FTR design had 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. The design should simply have provided for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The *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 13-1 The FTR/ARR 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.

Overview

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.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2023/2026 Long Term	6/2/2022	3/3/2023
2022/2023 ARR	2/28/2022	3/29/2022
2022/2023 Annual	4/5/2022	4/28/2022

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.)[4]
- 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.)

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

- 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.[5] (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.)
- 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.)

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.

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

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.[6] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[7] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. 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.

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

6 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

7 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

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.[8] 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").[9] While PJM's proposal will increase Stage 1A rights, this will 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

8 163 FERC ¶61,165 (2018).
9 See 178 FERC ¶61,170.

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.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic contract path based approach, and sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers, despite the fact that FTR buyers willingly paid a defined price for FTRs. PJM has significant discretion over the level of supply made available to FTR buyers. The appropriate goals of that discretion should be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[10] ARR target allocations are a set value at the time of the Annual FTR Auction. It is logically possible for ARRs to be revenue inadequate if the money collected from the FTR auction is not enough to pay the entirety of ARR target allocations for the planning period. This is extremely unlikely and can only happen if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

10 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. In the current approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

Market Design

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DUQ and DOM Control Zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least ten planning periods regardless of system or regulatory changes.[11]

In Stage 1A, LSEs can obtain ARRs, based on their lowest daily peak load in the prior twelve month period, and based on generation to load contract paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired and PJM has replaced it. The historical reference year is the year in which PJM markets were implemented, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year, subject to a cap of lowest daily peak load in the prior year. Network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of lowest daily peak load in the prior year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[12]

In Stage 1B, network transmission service customers can obtain ARRs based on their share of zonal peak load, based on generation to load contract paths, up to the difference between their share of zonal peak load and Stage 1A allocations. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

In Stage 2, network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable target allocations rather than the fixed ARR value determined in

11 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022) at 23.
12 See "PJM Manual 6: Financial Transmission Rights," Rev 29 (Sep. 1, 2022).

the annual FTR auction. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[13] ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[14]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[15] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[16] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion revenues are paid or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

Market Structure

ARRs are allocated on an annual basis. For the 2022/2023 planning period there were 1,563 individual participants and 133 parent companies.

The ownership of ARRs was unconcentrated, with an HHI of 584, for the 2022/2023 planning period.

Market Performance

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process. But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

For the 2019/2020 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. Stage 1A related over allocations have to be made up elsewhere in PJM's FTR market model, in the form of reduced system capability, in order for PJM to achieve its goal of fully funding FTRs.

13 OATT Attachment K 7.1.1.(b).
14 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022) at 35.
15 156 FERC ¶ 61,180 (2016).
16 See FERC Docket No. EL16-6-003.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[17] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2021 and September 2022.

There were 32,935 MW of ARRs associated with $2.5 million of revenue that were reassigned for the 2021/2022 planning period. There were 17,787 MW of ARRs associated with $1.8 million of revenue that were reassigned in the first four months of the 2022/2023 planning period.

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

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2021 through September 2022

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2021/2022 (12 months)	2022/2023 (4 months)	2021/2022 (12 months)	2022/2023 (4 months)
ACEC	300	188	$1.9	$0.9
AEP	4,142	2,075	$49.0	$18.7
APS	1,325	1,055	$15.5	$53.4
ATSI	3,353	3,678	$45.2	$59.3
BGE	2,393	1,059	$233.9	$157.1
COMED	3,056	796	$23.7	$4.9
DAY	1,074	807	$5.1	$4.3
DOM	120	35	$60.7	$0.9
DPL	832	369	$8.1	$25.1
DUKE	1,467	882	$53.0	$25.3
DUQ	1,662	896	$1.7	$3.6
EKPC	0	0	$0.0	$0.0
JCPLC	963	366	$2.0	$2.0
MEC	1,162	501	$9.4	$20.4
OVEC	0	0	$0.0	$0.0
PE	887	406	$14.7	$7.3
PECO	3,315	1,325	$11.5	$11.2
PEPCO	1,771	873	$63.3	$59.3
PPL	3,959	1,991	$16.8	$99.5
PSEG	1,116	463	$44.1	$14.9
REC	39	22	$0.1	$0.1
Total	32,935	17,787	$659.7	$568.2

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[18] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-4 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. 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 target allocation of $8.6 million. In the same time period for the 2021/2022 planning period, PJM allocated a total of 11,581.2 MW of residual ARRs with a target allocation of $7.0 million.

Table 13-4 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2022/2023 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021	43,484.2	25,028.0	57.6%	$11,677,033.36
2021/2022	46,092.0	27,619.2	59.9%	$18,806,123.46
2022/2023	29,826.9	11,699.9	39.2%	$8,556,779.80

* First four months of 2022/2023 planning period

18 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

IARRs

In theory, Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[19]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability.[20] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. There have been 13 successful IARR requests totaling 2,990.1 MW. One IARR path of 64.5 MW was terminated (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs. Of these 12 unique paths, three paths consisting of 1,200.0 MW were based on specific transmission investments requests, six paths consisting of 1,047.4 MW were based on merchant transmission requests and three paths consisting of 678.6 MW were based on customer funded (RTEP) transmission projects. The three paths based on specific transmission investments involved a generation company working with its affiliated transmission company. The other nine paths were based on projects that would have been built regardless of the addition of IARRs.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs

19 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.
20 See Attachment EE of the PJM Open Access Transmission Tariff <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.

is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[21]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[22] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights, which are given first and absolute priority in PJM's annual allocation process. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. These day-ahead congestion price differences, multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes. The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, auction revenues greater than ARR target allocations, and any charges made to day-ahead operating reserves which occur where there are hours with net negative congestion. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Target allocations are a cap on payments to FTR holders for each planning period. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available

21 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").

22 *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶61,077 (2006) ("Order No. 681"), *order on reh'g*, Order No. 618-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not fully recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. PJM's objective in the auctions is to maximize auction revenue, given the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is no requirement to report bilateral transactions, or any information about them, to PJM.

Supply and Demand

Total FTR supply in each auction is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

The FTR auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[23] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

Long Term FTR Auctions

In July 2006, FERC approved Order No. 681 mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets. FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights."[24] Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and is only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs

23 See the *2019 State of the Market Report for PJM*, Volume II, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

24 Order No. 681 at P 17.

obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages, determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. Capacity awarded in the Long Term FTR Auction is unavailable as ARRs in years two and three. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all possible capacity for ARR holders in the first year of the Long Term Auction due to changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[25] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear, is not defined and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. The Annual FTR Auction consists of four rounds that allow any PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Monthly Balance of Planning Period FTR Auctions

Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Before the 2020/2021 planning period, the first three individual months, and quarterly periods that had not yet begun, were available for bid or offer. Beginning with the 2020/2021 planning period, market participants can bid for or offer

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

monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[26]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

For bilateral trades reported to PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. Bilateral FTRs reported to PJM can also include more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time. Once the bilateral transaction is reported to PJM, PJM transfers ownership and adjusts credit requirements accordingly.

There is no reason to continue to permit bilateral transactions outside the PJM market and outside the awareness of PJM. The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market in order to provide full transparency consistent with the rest of the FTR market and to ensure no credit issues are missed.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks, trading firms and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs for the first nine months of 2022 by trade type, organization type and FTR direction. Financial entities purchased 80.9 percent of prevailing flow FTRs, down 3.0 percentage points, and 89.7 percent of counter flow FTRs, down 3.5 percentage points, from the same period in 2021, with the result that financial entities purchased 85.2 percent, down 3.0 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction for the first nine months of 2022.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September, 2022

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	19.1%	10.3%	14.8%
	Financial	80.9%	89.7%	85.2%
	Total	100.0%	100.0%	100.0%
Sell	Physical	7.3%	3.3%	6.2%
	Financial	92.7%	96.7%	93.8%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the monthly cumulative HHI values for cleared obligation MW for the first four months of the 2022/2023 planning period monthly auctions for prevailing flow FTRs. Ownership of cleared prevailing flow bids was unconcentrated in 88.1 percent of periods and moderately concentrated in 11.9 percent of periods.[27]

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

27 See *2021 State of the Market Report for PJM*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-22	468	588	582	1119	1216	848	691	704	620	802	694	793
Jul-22		417	519	886	1059	733	758	773	717	760	719	749
Aug-22			439	900	1074	775	824	760	749	746	713	769
Sep-22				737	1124	854	972	887	886	817	726	828

Table 13-7 shows the monthly cumulative HHI values for cleared obligation MW for the first four months of the 2022/2023 planning period monthly auctions by month for counter flow FTRs. Ownership of cleared counter flow bids was unconcentrated in 42.9 percent of periods and moderately concentrated in 57.1 percent of periods.

Table 13-7 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-22	776	735	786	930	1329	1194	1134	1382	1396	1358	945	973
Jul-22		576	614	822	1190	1092	984	1089	1113	1150	1014	973
Aug-22			573	844	1057	1017	935	1051	1085	1088	1020	961
Sep-22				744	1007	964	923	1079	1081	1150	1083	1021

Table 13-8 shows the average daily FTR ownership for all FTRs for 2022 by organization type, by FTR direction and self scheduled FTRs.

Table 13-8 Daily FTR held position ownership by FTR direction: 2022

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	25.8%	13.2%	19.8%
Physical Self Scheduled	9.3%	0.1%	4.9%
Financial	64.9%	86.7%	75.3%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[28] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[29] The use of both of these procedures is contingent on the conditions that: PJM actions not affect the revenue adequacy of allocated ARRs; all requested self scheduled FTRs clear; and net FTR auction revenue is positive.

Monthly Balance of Planning Period Auctions

Table 13-9 provides the monthly balance of planning period FTR auction market volume for the entire 2021/2022 and the first four months of the 2022/2023 planning periods. There were 10,847,723 MW of FTR obligation buy bids and 6,223,284 MW of FTR obligation sell offers for all bidding periods in the first four months of the 2022/2023 planning period.[30] The monthly balance of planning period FTR auction cleared 2,003,506 (18.5 percent) of FTR obligation buy bids and 1,028,740 MW (16.5 percent) of FTR obligation sell offers.

There were 929,957 MW of FTR option buy bids and 688,891 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2022/2023 planning period. The ownership of options was highly concentrated in all periods. The monthly auctions cleared 137,197 MW (14.8 percent) of FTR option buy bids and 180,538 MW (26.2percent) of FTR option sell offers.

28 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).
29 See *id.*
30 The term obligation is used only to distinguish FTRs from options.

Table 13-9 Monthly Balance of Planning Period FTR Auction market volume: 2022

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-22	Obligations	Buy bids	347,281	1,420,723	294,542	20.7%	1,126,181	79.3%
		Sell offers	217,573	856,794	157,653	18.4%	699,141	81.6%
	Options	Buy bids	7,286	147,128	9,773	6.6%	137,356	93.4%
		Sell offers	22,288	139,816	34,681	24.8%	105,135	75.2%
Feb-22	Obligations	Buy bids	342,266	1,564,997	305,847	19.5%	1,259,150	80.5%
		Sell offers	201,792	775,187	147,117	19.0%	628,070	81.0%
	Options	Buy bids	3,573	37,163	4,051	10.9%	33,112	89.1%
		Sell offers	18,257	84,000	20,412	24.3%	63,588	75.7%
Mar-22	Obligations	Buy bids	307,239	1,340,471	312,219	23.3%	1,028,252	76.7%
		Sell offers	158,195	622,295	122,833	19.7%	499,462	80.3%
	Options	Buy bids	3,148	31,658	3,436	10.9%	28,223	89.1%
		Sell offers	14,975	73,374	24,820	33.8%	48,554	66.2%
Apr-22	Obligations	Buy bids	223,837	995,215	258,312	26.0%	736,903	74.0%
		Sell offers	98,930	399,668	83,528	20.9%	316,140	79.1%
	Options	Buy bids	2,293	28,536	3,812	13.4%	24,724	86.6%
		Sell offers	8,405	68,557	43,985	64.2%	24,572	35.8%
May-22	Obligations	Buy bids	138,327	697,019	168,001	24.1%	529,019	75.9%
		Sell offers	45,661	190,405	42,010	22.1%	148,395	77.9%
	Options	Buy bids	434	5,637	1,628	28.9%	4,010	71.1%
		Sell offers	3,680	18,706	12,236	65.4%	6,470	34.6%
Jun-22	Obligations	Buy bids	671,874	3,957,062	715,263	18.1%	3,241,799	81.9%
		Sell offers	462,844	2,097,547	431,292	20.6%	1,666,256	79.4%
	Options	Buy bids	41,842	326,154	51,302	15.7%	274,851	84.3%
		Sell offers	58,109	197,179	80,089	40.6%	117,091	59.4%
Jul-22	Obligations	Buy bids	690,790	3,574,334	679,354	19.0%	2,894,980	81.0%
		Sell offers	554,273	2,125,017	332,754	15.7%	1,792,263	84.3%
	Options	Buy bids	31,606	299,370	42,702	14.3%	256,668	85.7%
		Sell offers	101,012	240,851	48,188	20.0%	192,664	80.0%
Aug-22	Obligations	Buy bids	652,317	3,316,327	608,889	18.4%	2,707,438	81.6%
		Sell offers	540,994	2,000,720	264,694	13.2%	1,736,026	86.8%
	Options	Buy bids	33,062	301,433	43,193	14.3%	258,240	85.7%
		Sell offers	89,247	250,861	52,262	20.8%	198,599	79.2%
Sep-22	Obligations	Buy bids	567,197	3,089,585	581,354	18.8%	2,508,231	81.2%
		Sell offers	448,420	1,832,869	208,678	11.4%	1,624,191	88.6%
	Options	Buy bids	33,563	317,894	40,366	12.7%	277,528	87.3%
		Sell offers	70,571	201,834	44,170	21.9%	157,664	78.1%
2021/2022*	Obligations	Buy bids	5,524,001	24,606,901	5,426,330	22.1%	19,180,571	77.9%
		Sell offers	3,662,125	13,289,542	2,601,701	19.6%	10,687,841	80.4%
	Options	Buy bids	172,879	4,370,065	259,467	5.9%	4,110,598	94.1%
		Sell offers	364,911	2,313,988	551,119	23.8%	1,762,869	76.2%
2022/2023**	Obligations	Buy bids	2,014,981	10,847,723	2,003,506	18.5%	8,844,217	81.5%
		Sell offers	1,558,111	6,223,284	1,028,740	16.5%	5,194,545	83.5%
	Options	Buy bids	106,510	926,957	137,197	14.8%	789,759	85.2%
		Sell offers	248,368	688,891	180,538	26.2%	508,353	73.8%

* Shows 12 months for 2020/2021 ** Shows 4 months for 2021/2022

Figure 13-1 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The prompt month is the final month for which FTRs for a specific month are sold. For example, June is the prompt month for June FTRs sold in the June auction, which occurs in May. The bid volume for the non-prompt months is significantly lower than for the prompt months. On average, the non-prompt month bid volume is 40.7 percent of the prompt month bid volume.

Figure 13-1 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June 2022 through September 2022 Auction

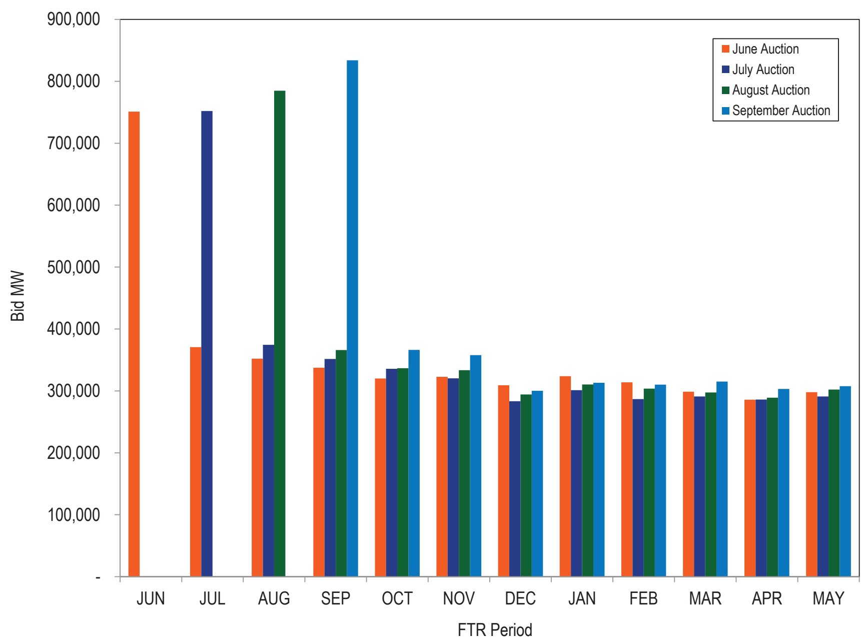


Figure 13-2 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt month cleared volume is 20.0 percent of the prompt month cleared volume.

Figure 13-2 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June 2022 through September 2022 Auction

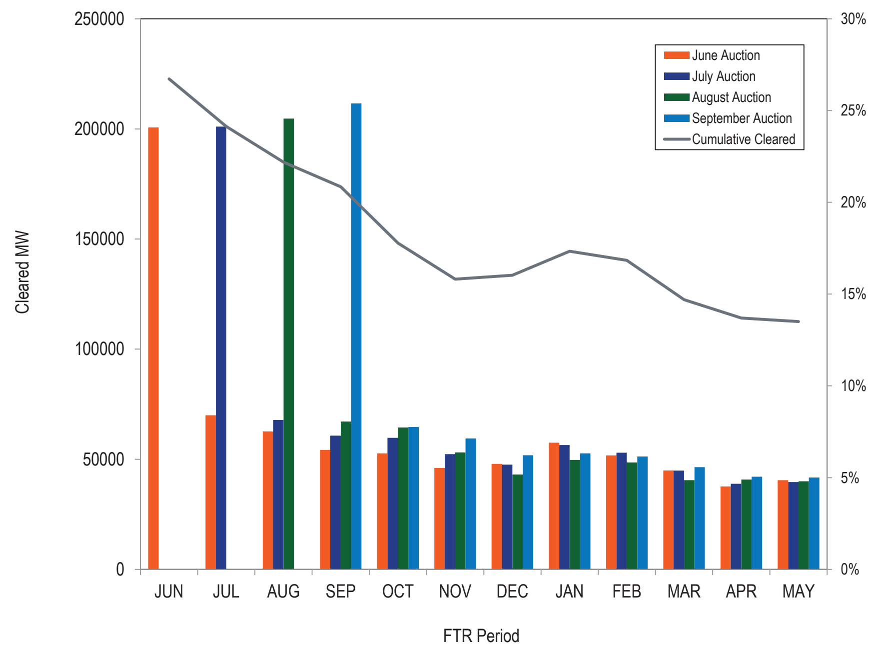


Figure 13-3 shows the FTR bid, net bid and cleared volume from June 2003 through September 2022 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. The cleared volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

Figure 13-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2022

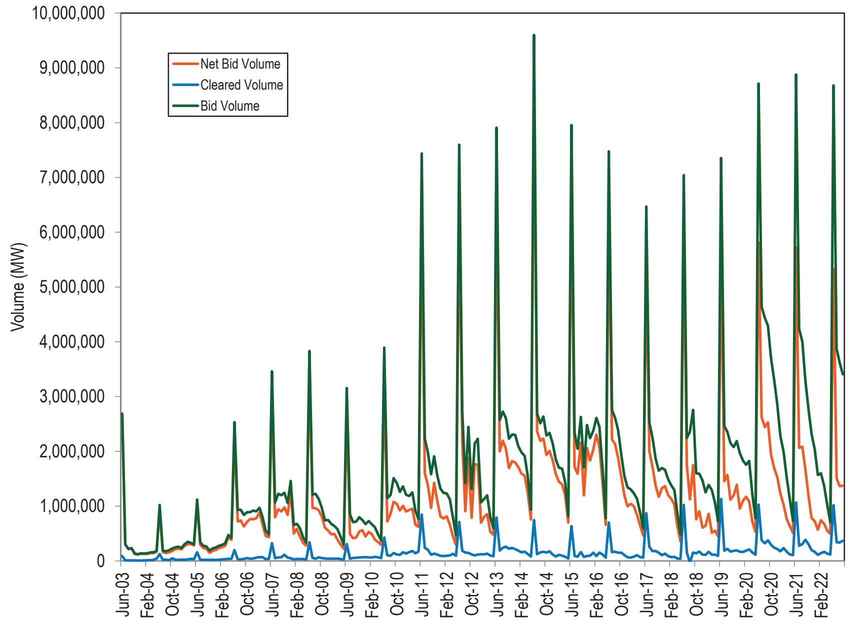


Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2022

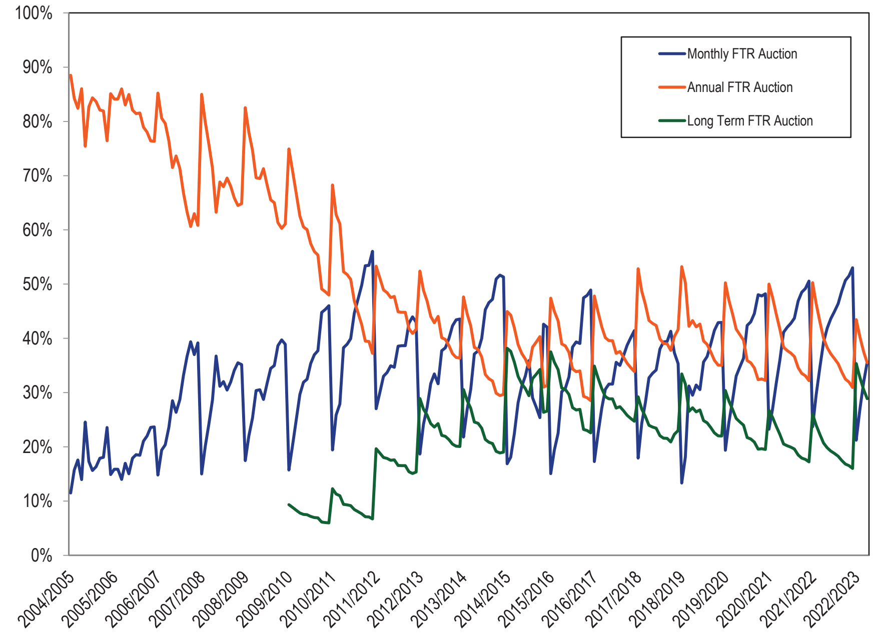


Figure 13-4 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2022. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

Bilateral Market

Table 13-10 provides the PJM registered secondary bilateral FTR market volume for the 2021/2022 and the 2022/2023 planning periods. Bilateral FTR transactions registered through PJM do not need to include an accurate price or the entire volume of the transaction. Bilateral FTR transactions are not required to be registered through PJM. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

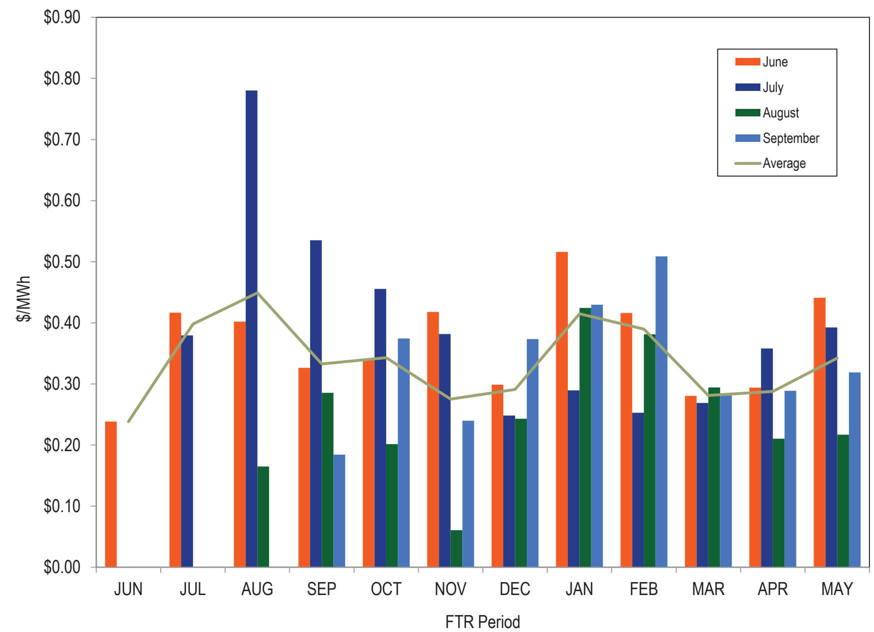
Table 13-10 Secondary bilateral FTR market volume: 2021/2022 and 2022/2023[31]

Planning Period	Type	Class Type	Volume (MW)
2021/2022	Obligation	24-Hour	6,275.4
		On Peak	99,564.8
		Off Peak	69,557.3
		Total	175,397.5
	Option	24-Hour	0.0
		On Peak	16,009.0
		Off Peak	20,846.6
		Total	36,855.6
2022/2023	Obligation	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0
	Option	24-Hour	246.6
		On Peak	106.6
		Off Peak	184.4
		Total	537.6

Price

Figure 13-5 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first four months of the 2022/2023 planning period and the average price per MWh for each of the FTR periods.

Figure 13-5 Monthly Balance of Planning Period FTR Auction cleared weighted-average buy bid price per period (Dollars per MWh): 2022/2023 planning period



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 the FTR. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to

31 The 2021/2022 planning period covers bilateral FTRs that are effective for any time between June 1, 2021 through May 31, 2022, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

FTRs. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported prices reflect the actual prices under the PJM rules. Bilateral profits and losses net to zero in market total profits and losses. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Profits in the first four months of the 2022/2023 planning period include the auction cost and revenue from both buying and selling FTRs that were effective between June 2022 and September 2022. This includes FTRs from the 2020/2023, 2021/2024 and 2022/2025 Long Term auctions, the 2022/2023 Annual auction, and the Monthly auctions from June 2022 through September 2022. The costs and revenues of the yearly FTR products are prorated based on the period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. The hourly revenues equal any positive hourly FTR target allocations, adjusted by the payout ratio plus any hourly auction revenues from the sale and/or the purchase of the FTR. The hourly auction costs equal any negative hourly FTR target allocations plus any hourly auction costs from the purchase and/or the sale of the FTR. The hourly auction costs and auction revenues are the product of the FTR MW and the auction price divided by the period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. The surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations for the current month or prior months in the planning period. A negative surplus (shortfall) at the end of the planning period is a deficiency that is charged as FTR uplift to FTR holders. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, after covering any shortfall in FTR target allocations within the planning period, the net surplus at the end of the planning period is distributed to ARR holders. Profits include any surplus distribution or uplift payments that was used to satisfy any shortfall in FTR target allocations.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every planning period from 2012/2013 through 2022/2023 except the 2016/2017 planning period, and were positive if summed over the entire period. Financial entities have been much more profitable than physical and physical ARR entities combined except for the 2015/2016 and the 2016/2017 planning periods (Table 13-13). It is not clear, in a competitive market, why FTR profits for financial entities remain persistently profitable and much more profitable than other participants. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-11 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction for the first four months of the 2022/2023 planning period. All participants who were assigned ARRs are classified as physical ARR. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

In the first four months of the 2022/2023 planning period, physical entities, including physical and physical ARR participants, 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 participants received $225.1 million in profits, up from $100.3 million in profits in the same time period in the 2021/2022 planning period. Self scheduled FTRs have zero cost. ARR holders who self scheduled FTRs received $294.2 million in congestion revenues, up from $92.3 million in revenue in the same time period in the 2021/2022 planning period. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits.

Table 13-11 FTR profits and revenues by organization type and FTR direction: 2022/2023: June through September

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$274,260,202	($49,180,697)	$225,079,505			
Physical	$87,517,682	($14,331,781)	$73,185,902			
Physical ARR	$55,836,434	($35,836,717)	$19,999,717	$288,815,805	$5,350,538	$294,166,343
Total	$417,614,319	($99,349,194)	$318,265,125	$288,815,805	$5,350,538	$294,166,343

Table 13-12 lists the monthly FTR profits for the 2021/2022 planning period and the 2022/2023 planning period by organization type. In the first four months of the 2022/2023 planning period, profits for all participants were $318.3 million, up from $144.8 million in profits for the same time period in the 2021/2022 planning period, and the highest level of profits since the 2013/2014 planning period. The increase in profits is due to the large increase in target allocation credit. The largest month to month increase in profits was in June, $56.2 million, while August was the most profitable month, $95.0 million. Among organization types, financial organizations had the largest increase in profits, $112.2 million, while physical ARR organizations' profit increased by $23.7 million.

Table 13-12 Monthly FTR profits by organization type: 2021/2022 and 2022/2023

	Organization Type			
Month	Financial	Physical	Physical ARR	Total
Jun-21	$22,749,776	$10,606,339	($1,804,140)	$31,551,975
Jul-21	$8,954,231	$1,444,400	($2,291,232)	$8,107,399
Aug-21	$46,644,100	$6,599,865	($1,540,329)	$51,703,636
Sep-21	$34,557,289	$16,956,350	$1,899,307	$53,412,946
Oct-21	$31,270,038	$25,268,849	$11,751,068	$68,289,955
Nov-21	$116,821,607	$43,470,687	$24,301,446	$184,593,740
Dec-21	$51,669,759	$17,990,752	$5,025,774	$74,686,286
Jan-22	$194,692,701	$48,237,853	($736,180)	$242,194,374
Feb-22	$78,598,638	$3,939,750	$2,163,530	$84,701,917
Mar-22	$33,362,979	$4,158,572	($2,300,900)	$35,220,651
Apr-22	$69,598,243	$14,635,329	($1,740,487)	$82,493,085
May-22	$142,570,155	$34,980,452	$435,586	$177,986,193
Summary for Planning Period 2021/2022				
Total	$831,489,515	$228,289,196	$35,163,444	$1,094,942,155
Jun-22	$38,826,556	$32,051,827	$16,902,773	$87,781,157
Jul-22	$51,488,899	$5,584,937	($3,493,815)	$53,580,021
Aug-22	$85,347,316	$13,777,652	($4,086,437)	$95,038,531
Sep-22	$49,416,734	$21,771,486	$10,677,196	$81,865,416
Summary for Planning Period 2022/2023				
Total	$225,079,505	$73,185,902	$19,999,717	$318,265,125

Table 13-13 lists the historical profits by planning period by organization type beginning in the 2012/2013 planning period for purchased FTRs. (Profits do not include congestion revenue to self scheduled FTRs.) End of year surplus is allocated to ARR holders and end of year shortfalls are allocated to FTR holders as uplift. There was a $112.3 million end of year surplus in the 2018/2019 planning period; a $140.7 million end of year surplus in the 2019/2020 planning period; a $14.5 million end of year shortfall in the 2020/2021 planning period; and a $29.5 million end of year shortfall in the 2021/2022 planning period.

Table 13-13 FTR profits by organization type: 2012/2013 through 2022/2023

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$225,079,505
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918					
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$225,079,505
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$225,079,505
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918					
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$225,079,505
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$73,185,902
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618					
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$73,185,902
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	$19,999,717
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635					
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186					
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	$19,999,717
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442	($113,614,490)	$360,510,126	$1,094,942,155	$318,265,125

* The first four months of the 2022/2023 planning period

Table 13-14 shows the profits and losses of the five most and the five least profitable participants by patterns of ownership. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row considers all ownership types when selecting the Top 5 and Bottom 5 participants. When all participants across ownership types are considered, three of the Top 5 participants and two of the Bottom 5 participants were financial participants. Of all the ownership types, the Top 5 physical ARR participants' share of profits was the highest, 95.7 percent, although the total profits of that group was the lowest. There are only a small number of physical ARR participants who directly purchase FTRs. The Bottom 5 financial participants' share of losses was the highest, 90.1 percent, although the difference with the other organization types' bottom 5 loss share is less than the difference in the top 5's profit share. When it is compared with the same period in the 2021/2022 planning period, the profitable participants earned more profits and the unprofitable participants had greater losses. The sum of top 5 participants' profits and profit per MWh increased for all ownership types. The Top 5 physical ARR participants' profit increase was the largest, $44.3 million or a more than five times increase in profits. The Top 5 physical ARR participants showed the largest increase in profit per MWh, making more than five times the profit per MWh compared with the same period in the 2021/2022 planning period. For the bottom 5 participants' losses, the sum of all ownership types' Bottom 5 participant losses and losses per MWh increased compared with the same time period in the 2021/2022 planning period. There are participants who have had persistent losses for multiple years. It is possible for PJM FTR participants to have complementary positions in other trading platforms such as the Intercontinental Exchange (ICE) or Nodal Exchange.

Table 13-14 Top 5 and bottom 5 FTR profits by ownership type: 2022/2023: June through September

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	1,071,334,714	$108,678,867	$0.50	20.1%	40.5%	($38,668,301)	($0.80)	4.5%	90.1%
Physical	169,276,689	$65,210,353	$1.25	30.9%	56.6%	($31,158,970)	($1.21)	15.2%	74.0%
Physical ARR	125,989,334	$54,243,787	$0.88	49.0%	95.7%	($26,710,528)	($0.74)	28.7%	72.8%
All	1,366,600,737	$153,562,593	$0.63	17.7%	34.9%	($57,592,361)	($0.94)	4.5%	47.3%

Table 13-15 shows the shares of the number of profitable and unprofitable participants by ownership type weighted by FTR MWh in the first four months of the 2022/2023 planning period. All ownership types had more profitable participants than unprofitable participants. Compared to the same period in the 2021/2022 planning period, the share of the profitable participants increased from 68.6 percent to 86.6 percent. The increase in the profitable financial participants' share was the largest, from 68.6 percent to 92.0 percent. Profitable physical participants' share decreased from 79.9 percent to 71.5 percent. In the first four months of the 2022/2023 planning period, there are fewer unprofitable participants but the sum of all the losses are greater than the sum of the losses in the same period in the 2021/2022 planning period. In other words, losses were more concentrated in the first four months in the 2022/2023 planning period than in the same period in the 2021/2022 planning period.

Table 13-15 Share of participants by profitability by ownership type: 2022/2023: June through September

Organization Type	Unprofitable	Profitable
Financial	8.0%	92.0%
Physical	28.5%	71.5%
Physical ARR	38.9%	61.1%
Total	13.4%	86.6%

Table 13-16 shows the profits by source and sink node type in the first four months of the 2022/2023 planning period. The sink total row is the sum of all profits and losses of FTRs that have the same sink node type. The source total column is the sum of all profits and losses of FTRs that have the same source node type. The profits of generator to generator FTRs were the largest, $129.9 million, which is equivalent to 40.8 percent of the total profits. The losses of hub to hub FTRs were the largest, -$28.8 million.

Table 13-16 Profits by node type matrix: 2022/2023: June through September

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$3,811,794	$210,305	$23,813,539	$224,897	$763,721	($106,295)	$1,144,501	**$1,666,812**	$31,529,275
EHVAGG	($57,456)	$375,135	$135,598	($32,951)	($2,201)	$920,571	$1,107	**$180,534**	$1,520,338
Generator	$15,458,186	$644,843	$129,875,827	$8,485,387	$2,965,376	$9,147,683	$15,829,507	**$72,121,359**	$254,528,167
Hub	($5,916,291)	$6,537	($997,661)	($28,816,931)	$1,178,113	($35,042)	($974,212)	**$7,946,645**	($27,608,841)
Interface	($212,831)	($3,657)	$158,287	($215,808)	($42,648)	($28,857)	$247,058	**$421,605**	$323,149
Load	$640,784	$501,939	($3,170,877)	$37,773	$75,980	$23,671,942	$79,967	**($266,113)**	$21,571,395
Residual Metered Aggregate	($209,304)	$20,109	($6,363,131)	$32,262	($6,158)	$36,185	$59,016	**($237,704)**	($6,668,725)
Zone	($1,624,768)	($1,499)	($9,437,772)	$30,527,777	($858,074)	$724,739	$1,065,728	**$22,674,236**	$43,070,367
Sink Total	$11,890,115	$1,753,712	$134,013,810	$10,242,406	$4,074,109	$34,330,925	$17,452,674	**$104,507,376**	$318,265,125

Table 13-17 shows the profit per MWh by source and sink node type in the first four months of the 2022/2023 planning period. The sink total row represents the average profit per MWh of FTRs that have the same sink type. The source total column shows the average profit per MWh of FTRs that have the same source type. Zone to load FTRs had the highest profit per MWh, $2.88 per MWh. Interface to EHVAGG FTRs had the largest loss per MWh, -$2.45 per MWh. Profit per MWh of generator to generator FTRs was $0.21 per MWh which is less than market average, $0.23 per MWh.

Table 13-17 Profit per MWh by node type matrix: 2022/2023: June through September

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$0.32	$2.14	$0.42	$0.15	$0.56	($0.07)	$0.19	$0.38	$0.38
EHVAGG	($0.47)	$0.42	$0.12	($0.80)	($0.41)	$0.27	$0.02	$1.90	$0.26
Generator	$0.18	$0.56	$0.21	$0.20	$0.33	$0.36	$1.03	$0.77	$0.29
Hub	($1.48)	$0.29	($0.18)	($1.21)	$0.79	($0.33)	($0.06)	$0.13	($0.25)
Interface	($0.70)	($2.45)	$0.08	($0.62)	($1.11)	($0.51)	$2.37	$0.48	$0.08
Load	$0.38	$0.34	($0.16)	$0.30	$0.58	$0.16	$0.22	($1.32)	$0.13
Residual Metered Aggregate	($0.22)	$0.84	($0.65)	$0.20	($0.15)	$0.10	$0.18	($0.55)	($0.55)
Zone	($0.33)	($0.36)	($0.74)	$1.16	($1.17)	$2.88	$0.06	$0.60	$0.43
Sink Total	$0.11	$0.48	$0.19	$0.11	$0.32	$0.19	$0.31	$0.53	$0.23

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-18 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for 2022. The Monthly Balance of Planning Period FTR Auctions for the first four months of the 2022/2023 planning period netted $68.4 million in revenue, the difference between buyers paying $354.6 million and sellers receiving $286.3 million. For the entire 2021/2022 planning period, the Monthly Balance of Planning Period FTR Auctions netted $50.3 million in revenue with buyers paying $412.5 million and sellers receiving $362.2 million. Revenue from obligation buy bids for the 2022/2023 planning period were up 77.3 percent over the same period last planning period. Revenue from obligation sell offers was up 83.2 percent over the same period last planning period.

Table 13-18 Monthly Balance of Planning Period FTR Auction revenue: 2022

Monthly Auction	Type	Trade Type	Class Type 24-Hour	On Peak	Off Peak	All
Jan-22	Obligations	Buy bids	$4,656,308	$14,876,888	$6,659,635	$26,192,831
		Sell offers	$3,551,375	$11,588,508	$3,216,594	$18,356,477
	Options	Buy bids	$54,488	$1,770,242	$921,334	$2,746,065
		Sell offers	$2,044,952	$4,161,379	$3,127,868	$9,334,199
Feb-22	Obligations	Buy bids	($785,122)	$8,782,484	$6,697,220	$14,694,582
		Sell offers	($10,515,691)	$8,921,383	$7,670,037	$6,075,728
	Options	Buy bids	$149,626	$377,326	$403,923	$930,875
		Sell offers	$1,560,835	$3,477,681	$2,267,008	$7,305,524
Mar-22	Obligations	Buy bids	$4,293,477	$12,963,102	$8,013,588	$25,270,168
		Sell offers	$1,934,090	$10,689,355	$5,167,586	$17,791,031
	Options	Buy bids	$105,143	$632,313	$428,144	$1,165,599
		Sell offers	$1,713,386	$3,560,352	$2,347,613	$7,621,350
Apr-22	Obligations	Buy bids	$175,026	$9,043,344	$12,230,001	$21,448,370
		Sell offers	$1,754,378	$4,778,810	$7,622,909	$14,156,096
	Options	Buy bids	$101,441	$527,185	$730,557	$1,359,183
		Sell offers	$923,659	$1,873,873	$2,200,803	$4,998,335
May-22	Obligations	Buy bids	$3,652,224	$3,597,368	$6,348,570	$13,598,161
		Sell offers	$2,829,943	$2,506,759	$4,755,176	$10,091,878
	Options	Buy bids	$5	$141,262	$119,673	$260,940
		Sell offers	$932,209	$1,032,146	$1,271,438	$3,235,793
Jun-22	Obligations	Buy bids	$13,163,858	$52,508,561	$26,023,939	$91,696,358
		Sell offers	$841,198	$40,601,524	$19,516,441	$60,959,163
	Options	Buy bids	$1,428,912	$8,828,452	$5,718,200	$15,975,564
		Sell offers	$1,778,905	$10,364,933	$6,746,904	$18,890,741
Jul-22	Obligations	Buy bids	$24,572,208	$57,720,557	$20,715,450	$103,008,216
		Sell offers	$2,355,714	$52,762,421	$18,972,814	$74,090,949
	Options	Buy bids	$474,856	$4,529,610	$4,282,325	$9,286,791
		Sell offers	$1,304,364	$11,015,170	$5,728,357	$18,047,890
Aug-22	Obligations	Buy bids	$4,203,921	$31,888,518	$15,357,563	$51,450,002
		Sell offers	$2,809,085	$20,016,366	$10,230,627	$33,056,079
	Options	Buy bids	$674,193	$4,249,358	$4,424,568	$9,348,119
		Sell offers	$997,250	$9,624,715	$5,890,321	$16,512,286
Sep-22	Obligations	Buy bids	$5,043,318	$34,993,998	$23,123,361	$63,160,678
		Sell offers	$1,917,572	$28,904,607	$17,870,860	$48,693,039
	Options	Buy bids	$271,782	$4,839,618	$5,604,083	$10,715,484
		Sell offers	$1,529,857	$8,189,287	$6,319,640	$16,038,784
2021/2022*	Obligations	Buy bids	$130,170,799	$93,071,867	$154,936,269	$378,178,935
		Sell offers	$8,296,880	$98,421,764	$155,017,657	$261,736,301
	Options	Buy bids	$2,675,547	$14,067,533	$17,605,969	$34,349,049
		Sell offers	$19,136,817	$36,088,621	$45,266,394	$100,491,832
	Net Total		$105,412,649	($27,370,984)	($27,741,813)	$50,299,852
2022/2023**	Obligations	Buy bids	$46,983,306	$177,111,635	$85,220,313	$309,315,254
		Sell offers	$7,923,569	$142,284,918	$66,590,742	$216,799,229
	Options	Buy bids	$2,849,744	$22,447,038	$20,029,176	$45,325,959
		Sell offers	$5,610,375	$39,194,105	$24,685,222	$69,489,702
	Net Total		$36,299,105	$18,079,650	$13,973,526	$68,352,281

* Shows twelve months for 2021/2022 **Shows four months for 2022/2023

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-6 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first four months of the 2022/2023 planning period. The top 10 sinks that produced financial benefit accounted for 27.8 percent of total positive target allocations with the Western Hub accounting for 7.7 percent of all positive target allocations. The top 10 sinks that created liability accounted for 18.9 percent of total negative target allocations with PSEG accounting for 3.1 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2022/2023

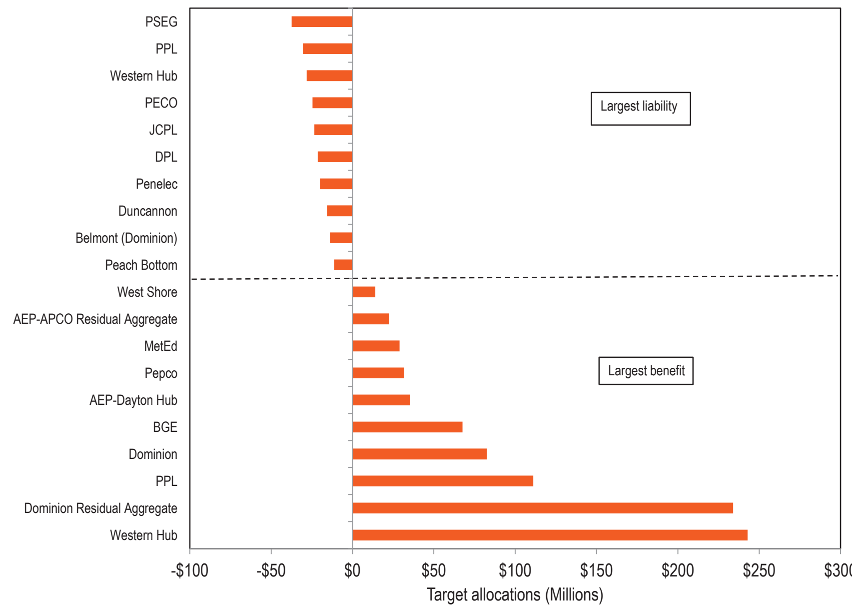
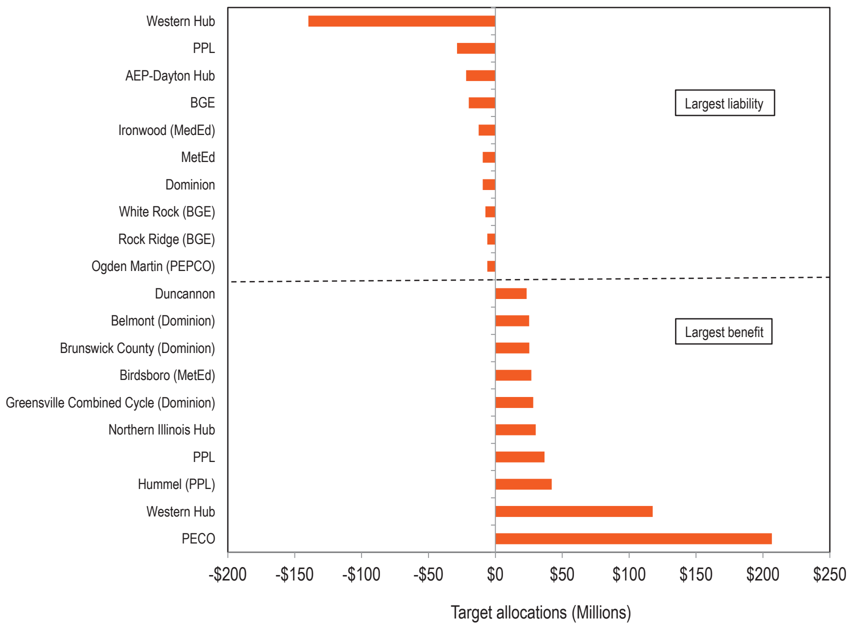


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first four months of the 2022/2023 planning period. The top 10 sources with a positive target allocation accounted for 18.2 percent of total positive target allocations with the PECO Zone accounting for 6.7 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 21.9 percent of all negative target allocations, with the Western Hub accounting for 11.7 percent of total negative target allocations.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2022/2023



The Effect of Fast Start Pricing on FTR Target Allocations

PJM implemented fast start pricing on September 1, 2021. As a result of these changes, PJM produces two separate dispatch and pricing solutions. The dispatch run results in dispatch instructions and matching prices, termed dispatch run locational marginal price, or DLMP. The DLMP prices are the prices that would have been the LMPs prior to fast start pricing. The pricing run results in the final prices used in settlements and for FTR target allocations, termed pricing run locational marginal price, or PLMP. The two runs result in different sets of target allocations for the same FTR paths. Table 13-19 compares the target allocations that result from the pricing and dispatch runs for both self scheduled and all other FTRs for the 2021/2022 and 2022/2023 planning periods. The difference indicates whether the target allocations were increased or decreased as a result of fast start pricing.

Table 13-19 Pricing run and dispatch run FTR Target Allocations: 2021/2022 and 2022/2023 planning periods

Planning Period		Pricing Run	Dispatch Run	Difference	Percent Difference
2021/2022*	Not Self Scheduled	$1,499,077,738.2	$1,497,963,894.6	$1,113,843.6	0.1%
	Self Scheduled	$429,271,338.2	$430,800,597.9	($1,529,259.7)	(0.4%)
	Total	$1,928,349,076.4	$1,928,764,492.5	($415,416.1)	(0.0%)
2022/2023**	Not Self Scheduled	$732,398,924.6	$738,850,231.9	($6,451,307.3)	(0.9%)
	Self Scheduled	$294,165,621.8	$310,453,195.9	($16,287,574.1)	(5.5%)
	Total	$1,026,564,546.4	$1,049,303,427.7	($22,738,881.4)	(2.2%)

* starting in September 2021

** first four months of the 2021/2022 planning period

Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. In fact, there is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason and should be settled monthly.

Surplus day-ahead congestion is defined as the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[32] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[33] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus is distributed to ARR holders.[34]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-8 shows the distribution of the monthly surplus congestion revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning period, if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus congestion in that month to make FTRs whole. For example, September 2020 did not have enough surplus congestion to make FTRs whole. Those FTRs were made whole using surplus revenue from previous months. One of the first four months of the 2022/2023 planning period did not have enough revenue to pay FTR target allocations, represented by lines that are entirely above the surplus bars. In the first four months of the 2022/2023 planning period, $101.8 million was paid from individual monthly surplus amounts to cover shortfalls in months with a shortfall.

The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. 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. In Figure 13-8 the amount represented by each bar would be assigned to ARR holders in every month. In the first four months of the 2022/2023 planning period, $30.6 million of surplus congestion revenue was paid to FTR holders that would have been paid to ARR holders under the MMU recommendation. The significant increase in surplus congestion revenue in 2022 was the result of increased day-ahead congestion, without a corresponding increase in target allocations. Day-ahead congestion increased by $1,508.8 million, 194.8 percent, from $774.7 million in the first nine months of 2021 to $2,283.5 million in the first nine months of 2022. Target allocations increased by $1,317.9 million, 139.4 percent, from $945.4 million in the first 9 months of 2021 to $2,263.3 million in the first nine months of 2022. This disconnect between target allocations and congestion is a result of incorrectly defined property rights in the current ARR/FTR market design.

32 Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day-ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

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

34 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

Figure 13-8 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through September 2022[35]

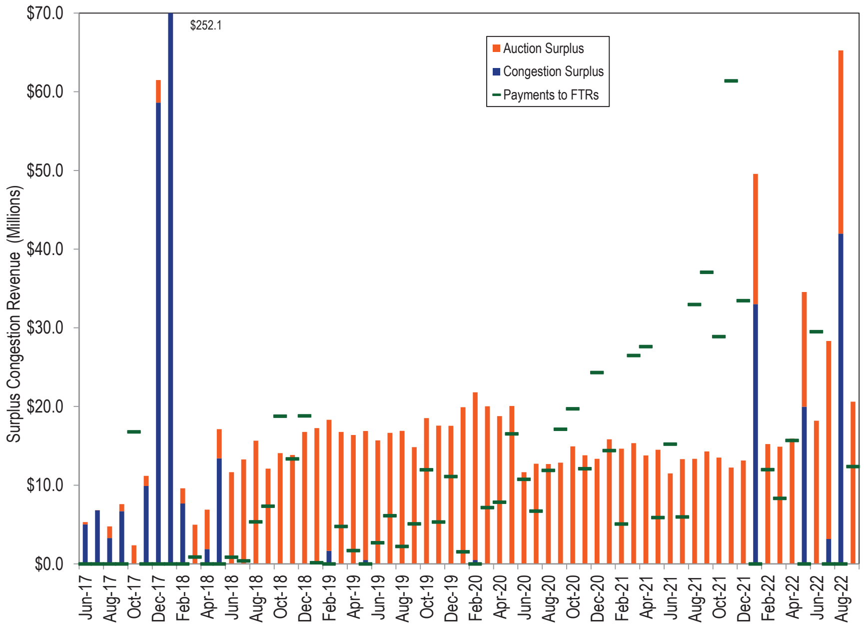
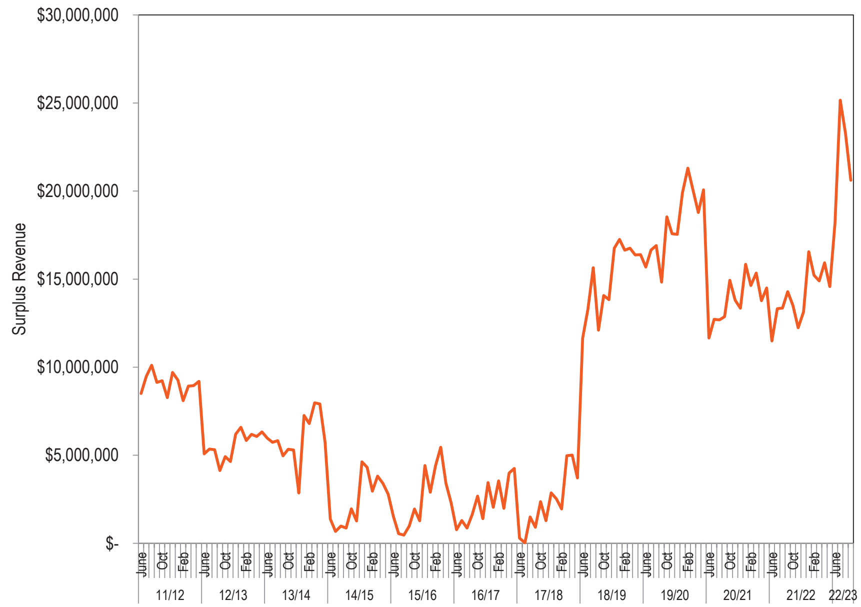


Figure 13-9 shows the surplus FTR auction revenue from the 2011/2012 planning period through the first four months of the 2022/2023 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-9 Monthly FTR auction surplus: 2011/2012 through 2022/2023



35 The bar January 2019 is truncated.

Table 13-20 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first four months of the 2022/2023 planning period.

Table 13-20 Surplus FTR Auction Revenue: 2010/2011 through 2022/2023[36]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021	$166.1	($185.1)	($14.5)
2021/2022	$168.5	$198.0	($29.5)
2022/2023**	$872.5	($3.2)	$90.5
Total	$1,996.7	($2,232.1)	($687.5)

*Start of counter flow "buy back"
**First four months

Revenue Adequacy

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

As defined, FTR revenue adequacy simply compares congestion revenues to FTR target allocations. (Target allocations are the CLMP differences between the source and sink of the FTR times the MW of the FTR.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

Actual congestion revenues are not a result of PJM's decisions about the FTR auction model. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available system capability in the ARR/FTR market model through outage selection for the 2014/2015 through 2016/2017 planning periods resulted in a high level of revenue adequacy at the expense of a reduction in available ARRs and associated FTRs. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. Instead, PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency

36 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. For that reason, ARRs have unsurprisingly been revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load, or even much less.

Total net FTR auction revenue for the 2021/2022 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $812.6 million. For the first four months of the 2022/2023 planning period, total net FTR auction revenue was $1,626.6 million.

Table 13-21 presents the PJM FTR revenue detail for the 2021/2022 planning period and the 2022/2023 planning period. This includes ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[37] In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion. A negative deficiency is a surplus, which will be distributed to ARR holders at the end of the planning period, while a positive deficiency is a shortfall, which will be charged as FTR uplift at the end of the planning period.

37 The final ARR values may change if load shifts.

Table 13-21 Total annual ARR and FTR revenue detail (Dollars (Millions)): 2021/2022 and 2022/2023

Accounting Element	2021/2022	2022/2023
ARR information		
ARR target allocations	$634.2	$1,320.8
ARR credits	$634.2	$1,320.8
FTR auction revenue	$812.6	$1,626.6
Annual FTR Auction net revenue	$692.4	$1,501.5
Long Term FTR Auction net revenue	$69.9	$56.8
Monthly Balance of Planning Period FTR Auction net revenue	$50.3	$68.4
Surplus auction revenue		
ARR Surplus	$168.5	$87.3
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$2,902.9	$1,225.6
Negative target allocations	($652.2)	($199.1)
FTR target allocations	$2,250.6	$1,026.5
Adjustments:		
Adjustments to FTR target allocations	$0.0	$0.0
Total FTR targets	$2,250.6	$1,026.5
FTR payout ratio	99.0%	100.0%
FTR revenues		
ARR excess	$168.5	$87.3
Congestion		
Net Negative Congestion (enter as negative)	$0.0	$0.0
Hourly congestion revenue	$2,052.6	$1,029.7
M2M Payments(credit to PJM minus credit to M2M entity)	$0.0	$0.0
Adjustments:		
Surplus revenues carried forward into future months	$3.6	$0.0
Surplus revenues distributed back to previous months	$97.9	$11.3
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Surplus revenues distributed to other months	$101.5	$0.0
Net Negative Congestion charged to DA Operating Reserves	$0.0	$11.3
Total FTR congestion credits	$2,221.1	$1,128.3
Total congestion credits(includes end of year distribution)	$2,221.1	$1,128.3
Remaining deficiency	$29.5	($90.5)

* First four months of 2022/2023

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-22 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. In this table, the monthly credit surplus/

deficiency indicates the deficiency for the given month, and is negative if there is an excess and positive if there is a deficiency.

The total row in Table 13-22 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-22 Monthly FTR accounting summary (Dollars (Millions)): 2021/2022 and 2022/2023

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus/Deficiency (with adjustments)
Jun-21	$97.7	$101.5	96.3%	$101.5	100.0%	$0.0
Jul-21	$86.5	$79.1	100.0%	$86.5	100.0%	($7.4)
Aug-21	$121.5	$141.1	86.1%	$141.1	100.0%	$0.0
Sep-21	$110.7	$133.5	82.9%	$133.5	100.0%	$0.0
Oct-21	$126.7	$142.1	89.2%	$142.1	100.0%	$0.0
Nov-21	$220.9	$270.1	81.8%	$260.9	96.6%	$44.0
Dec-21	$126.1	$146.4	86.1%	$126.1	86.1%	$20.3
Jan-22	$459.8	$410.2	100.0%	$459.6	100.0%	($49.6)
Feb-22	$174.1	$170.9	100.0%	$174.1	100.0%	($3.2)
Mar-22	$114.2	$107.6	100.0%	$114.2	100.0%	($6.6)
Apr-22	$161.9	$161.6	100.0%	$161.9	100.0%	($0.2)
May-22	$421.0	$386.4	100.0%	$421.0	100.0%	($34.5)
			Summary for Planning Period 2021/2022			
Total	$2,221.1	$2,250.6		$2,322.3		$29.5
Jun-22	$220.2	$231.5	95.1%	$231.5	100.0%	$0.0
Jul-22	$248.7	$220.4	100.0%	$248.7	100.0%	($28.3)
Aug-22	$378.9	$313.7	100.0%	$378.9	100.0%	($65.3)
Sep-22	$269.1	$260.9	100.0%	$269.1	100.0%	($8.2)
			Summary for Planning Period 2022/2023			
Total	$1,117.0	$1,026.5		$1,128.3		($90.5)

* First four months of the 2022/2023 planning period

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2022. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-10 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for months with a payout ratio less than 100 percent in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period and assigned to prior months.

Figure 13-10 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2022

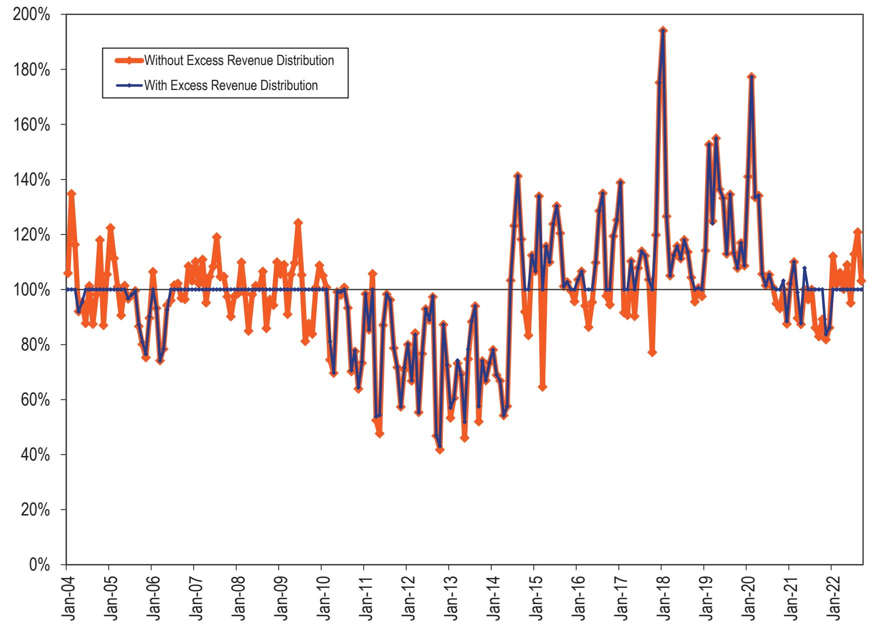


Table 13-23 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. The 2013/2014 planning period includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

The first four months of the 2022/2023 planning period had a payout ratio of 100.0 percent.

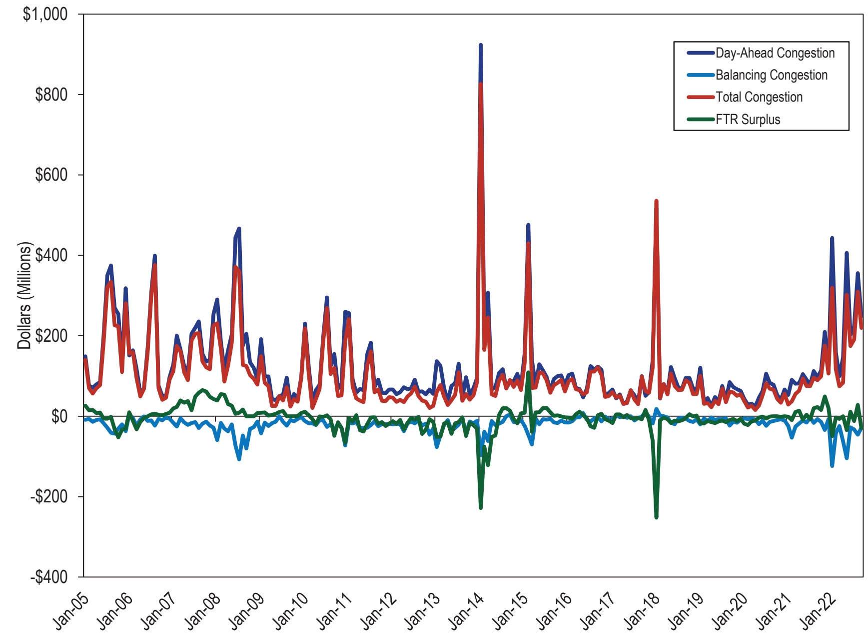
Table 13-23 Reported FTR payout ratio by planning period[38]

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	98.7%
2021/2022	99.0%
2022/2023	100.0%

* First four months of 2022/2023

Figure 13-11 shows the day-ahead, balancing and total congestion payments from January 2005 through September 2022.

Figure 13-11 FTR surplus and day-ahead, balancing and total congestion: 2005 through September 2022



Target Allocations and Congestion by Constraint

One of the reasons that the current path based ARR/FTR market design does not provide a reasonable way to return congestion to load is because target allocations on the FTR paths do not align with congestion based on actual network use. A comparison of the FTR target allocations for individual constraints to the day-ahead and total congestion by constraint provides evidence of this misalignment. Total congestion is the sum of day-ahead and balancing congestion. If FTR target allocations on some paths are significantly greater than actual congestion and FTR target allocations on other paths are significantly less than actual congestion, this is evidence of a serious flaw in the design. It is evidence that the FTR design is not meeting its goal of paying out congestion, regardless of the recipients.

38 The actual payout ratios for the 2006/2007, 2007/2008, and 2008/2009 planning periods may have exceeded 100 percent.

FTR target allocations are the result of constraints on day-ahead paths in the energy market. Any specific FTR path may be affected by multiple constraints. Constraints that result in FTR target allocations greater than the congestion that results from those constraints mean that the FTR target allocations are greater than the actual congestion. Figure 13-12 shows the constraints that are the top 10 sources of positive FTR target allocations, for the first four months of the 2022/2023 planning period. Figure 13-12 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints.

Figure 13-12 Top ten constraint sources of positive FTR target allocations: 2022/2023

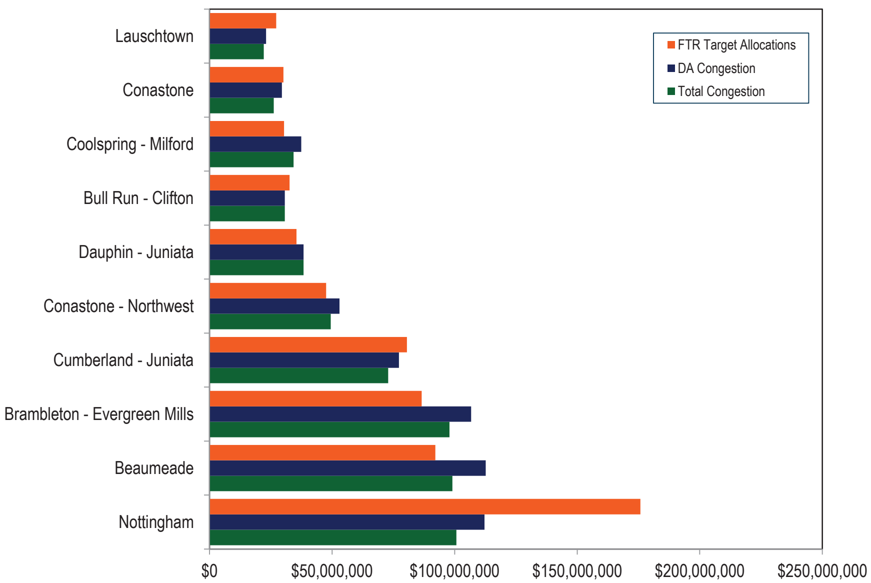
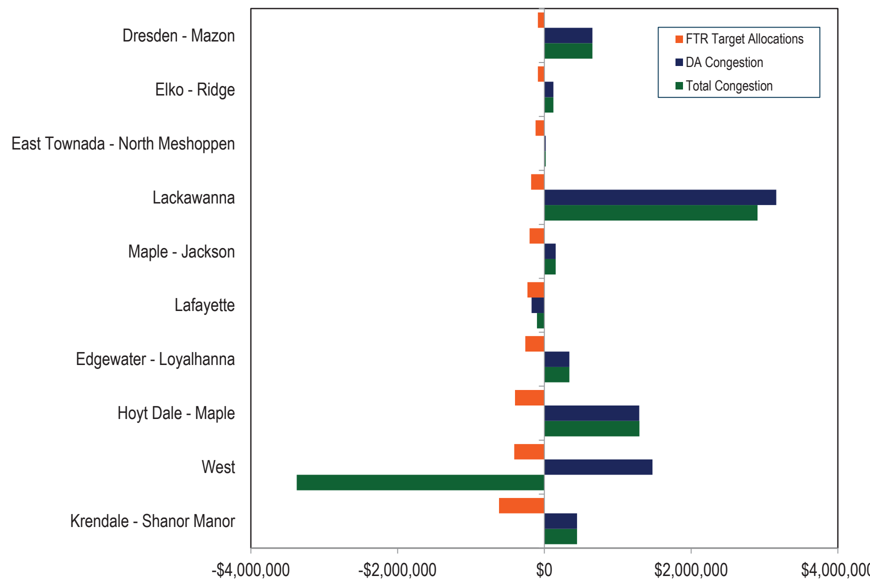


Figure 13-13 shows the constraints that are the top 10 sources of negative FTR target allocations, for the first four months of the 2022/2023 planning period. Figure 13-13 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraint.

In the first four months of the 2022/2023 planning period, there were 25 constraints that are the source of negative target allocations. Of the 25 constraints with negative target allocations, 21 resulted in positive actual total congestion. Constraints that contribute positive congestion revenues and have negative FTR target allocations are a source of funds used in the settlement process to pay for FTR target allocations on FTR paths that are over allocated relative to actual congestion.

Figure 13-13 Top ten constraint sources of negative FTR target allocations: 2022/2023



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-24 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The highlighted offsets are the actual offsets based on the rules that were effective in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments.

Total ARR and self scheduled FTR revenue offset 62.9 percent of total congestion costs for the first four months 2022/2023 planning period.

Table 13-24 ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2022/2023

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021*	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022	$469.7	$500.3	$2,082.0	($457.4)	$1,624.6	($101.7)	($0.0)	($0.0)	$868.3	53.4%	$512.5	31.5%	$512.5	31.5%	$512.5	31.5%
2022/2023	$327.1	$294.2	$1,029.7	($172.3)	$857.5	($23.4)	$25.9	$90.5	$597.9	69.7%	$475.0	55.4%	$539.5	62.9%	$667.8	62.9%
Total	$5,686.9	$3,320.9	$14,549.8	($2,874.3)	$11,675.4	($346.5)	$338.8	$1,626.6	$8,661.3	74.2%	$6,472.3	55.4%	$7,760.1	66.5%	$7,888.2	67.6%

* First four months of the 2022/2023 planning period

Table 13-24 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

Table 13-25 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for the planning period and prior planning periods.

The cumulative offset was 67.6 percent based on the rules that were in place for each planning period. Load has been underpaid by $3.8 billion from the 2011/2012 planning period through the first four months of the 2022/2023 planning period.

Table 13-25 ARR and self scheduled FTR cumulative offset for ARR holders: 2011/2012 through 2022/2023

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	103.4%	$25.3
2012/2013	102.4%	$31.2
2013/2014	67.8%	($1,012.9)
2014/2015	66.7%	($1,498.3)
2015/2016	70.9%	($1,589.2)
2016/2017	75.0%	($1,556.9)
2017/2018	71.0%	($2,156.7)
2018/2019	72.7%	($2,215.4)
2019/2020	76.3%	($2,030.2)
2020/2021	74.4%	($2,357.2)
2021/2022	67.9%	($3,469.3)
2022/2023	67.6%	($3,787.2)

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no reason that this should be the result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. The misalignment of path based ARR rights produces cross subsidies among ARR holders.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[39]

Table 13-26 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[40] The offset for the 2022/2023 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-26 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-26 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

39 *See* "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.
40 See *2020 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses

Table 13-26 Zonal ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2022/2023 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$1.2	$0.1	($2.4)	$0.25	($0.9)	$11.0	($2.0)	($0.4)	$8.7	(10.4%)
AEP	$27.6	$33.1	($25.2)	$12.5	$47.9	$161.3	($21.1)	($4.1)	$136.1	35.2%
APS	$21.6	$10.2	($9.8)	$6.7	$28.7	$60.2	($8.3)	($1.5)	$50.4	57.0%
ATSI	$12.9	$0.3	($13.0)	$2.6	$2.7	$80.0	($10.8)	($2.2)	$66.9	4.0%
BGE	$48.9	$3.3	($7.3)	$10.1	$55.0	$43.0	($6.2)	($1.1)	$35.7	154.1%
COMED	$14.3	$0.0	($17.7)	$2.8	($0.6)	$114.1	($14.5)	($3.2)	$96.3	(0.6%)
DAY	$3.0	$0.3	($3.6)	$0.7	$0.5	$20.3	($3.0)	($0.6)	$16.7	2.8%
DOM	$13.3	$216.9	($26.5)	$3.2	$207.0	$163.3	($22.6)	($3.8)	$136.8	151.3%
DPL	$27.6	$4.1	($4.2)	$0.7	$28.2	$30.8	($3.6)	($0.6)	$26.6	106.0%
DUKE	$14.6	$3.5	($5.8)	$13.8	$26.0	$34.4	($4.9)	($0.9)	$28.6	91.0%
DUQ	$3.7	$0.1	($2.8)	$6.5	$7.5	$12.0	($2.3)	($0.5)	$9.3	81.1%
EKPC	$2.3	$0.0	($2.7)	$0.5	$0.0	$15.6	($2.3)	($0.4)	$12.9	0.3%
EXT	$0.0	$0.0	($5.1)	$0.0	($5.1)	$20.0	($5.1)	$0.0	$14.9	(34.2%)
JCPLC	$2.5	$0.0	($5.9)	$0.5	($2.9)	$31.7	($5.1)	($0.8)	$25.8	(11.0%)
MEC	$15.6	$2.2	($4.2)	$3.3	$16.9	$19.9	($3.7)	($0.5)	$15.7	107.9%
OVEC	$0.0	$0.0	($0.2)	$0.0	($0.2)	$1.6	($0.2)	$0.0	$1.4	(14.1%)
PE	$6.4	$4.0	($3.4)	$2.4	$9.5	$19.8	($2.8)	($0.5)	$16.4	57.7%
PECO	$9.0	$4.7	($8.2)	$1.9	$7.5	$49.8	($6.8)	($1.4)	$41.7	17.9%
PEPCO	$24.0	$2.1	($6.6)	$5.1	$24.6	$38.8	($5.6)	($1.0)	$32.2	76.4%
PPL	$45.9	$8.0	($7.9)	$10.0	$56.0	$49.6	($6.5)	($1.3)	$41.7	134.2%
PSEG	$32.3	$1.3	($9.5)	$6.9	$31.1	$50.7	($7.9)	($1.6)	$41.2	75.4%
REC	$0.3	$0.0	($0.3)	$0.1	$0.0	$1.8	($0.3)	($0.1)	$1.4	0.9%
Total	$327.1	$294.2	($172.3)	$90.5	$539.5	$1,029.7	($145.6)	($26.7)	$857.5	62.9%

The total congestion offset paid to loads in the first four months of the 2022/2023 planning period was 62.9 percent of congestion costs. The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like ATSI, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

The amount and proportion of the offset that can be realized by load serving entities via their ARR allocations varies by planning period. The offsets are a function of the assignment of ARRs relative actual network sources of congestion paid, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM’s ARR/FTR design has consistently failed to return the congestion revenues to the load that paid it. It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths.

Offset if all ARRs are Held as ARRs

Table 13-27 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARRs holders held all their allocated ARRs in the 2020/2021, 2021/2022, and the first four months of the 2022/2023 planning period and did not self schedule any.

Table 13-27 Offset available to load if all ARRs are held: 2019/2020 through 2021/2022 planning periods

	20/21 Planning Period				21/22 Planning Period				22/23 Planning Period			
	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset
ACEC	$4.4	($2.7)	$5.5	31.2%	$4.0	($5.2)	$14.8	(8.0%)	$1.3	($2.4)	$8.7	(12.7%)
AEP	$85.3	($38.1)	$110.9	42.6%	$84.2	($65.7)	$240.4	7.7%	$62.6	($25.2)	$136.1	27.5%
APS	$50.5	($14.8)	$45.2	79.0%	$43.3	($29.7)	$122.8	11.0%	$33.7	($9.8)	$50.4	47.5%
ATSI	$20.5	($19.5)	$50.6	2.1%	$26.3	($32.3)	$117.9	(5.1%)	$13.0	($13.0)	$66.9	0.0%
BGE	$61.1	($9.1)	$24.8	209.2%	$102.8	($17.0)	$59.9	143.2%	$50.7	($7.3)	$35.7	121.5%
COMED	$43.2	($28.5)	$78.3	18.8%	$43.0	($44.7)	$159.9	(1.1%)	$14.3	($17.7)	$96.3	(3.6%)
DAY	$6.4	($5.3)	$11.0	9.8%	$6.1	($8.6)	$26.2	(9.6%)	$3.3	($3.6)	$16.7	(1.6%)
DOM	$67.5	($37.9)	$87.9	33.7%	$87.1	($22.0)	$370.9	17.5%	$69.1	($26.5)	$140.2	30.4%
DPL	$32.8	($6.7)	$36.2	72.0%	$50.9	($80.3)	($21.1)	139.2%	$32.5	($4.2)	$23.4	120.6%
DUKE	$28.8	($8.4)	$17.4	117.5%	$27.8	($12.3)	$23.7	65.3%	$16.3	($5.8)	$28.6	36.5%
DUQ	$5.8	($4.0)	$6.2	28.7%	$6.7	($6.4)	$45.3	0.5%	$3.7	($2.8)	$9.1	10.9%
EKPC	$3.0	($4.2)	$8.4	(13.3%)	$3.9	($7.0)	$21.9	(14.2%)	$2.3	($2.7)	$12.9	(3.4%)
EXT	$0.5	($13.8)	$11.0	(120.7%)	$0.7	($9.9)	$19.9	(46.2%)	NA	($5.1)	$14.9	(34.2%)
JCPLC	$6.1	($6.1)	$12.9	(0.1%)	$2.1	($12.8)	$39.0	(27.4%)	$2.5	($5.9)	$25.8	(13.0%)
MEC	$3.9	($5.3)	$16.5	(8.4%)	$9.3	($11.6)	$33.2	(6.7%)	$16.7	($4.2)	$15.7	80.0%
OVEC	NA	($0.3)	$0.9	(28.8%)	NA	($0.4)	$1.5	(29.4%)	NA	($0.2)	$1.4	(14.1%)
PE	$9.3	($6.5)	$16.4	16.7%	$13.1	($18.5)	$31.8	(17.2%)	$9.6	($3.4)	$16.4	38.0%
PECO	$15.1	($10.9)	$24.9	17.0%	$21.5	($12.0)	$78.0	12.1%	$12.2	($8.2)	$41.7	9.7%
PEPCO	$29.1	($8.3)	$20.5	101.6%	$31.3	($15.5)	$53.8	29.3%	$25.5	($6.6)	$32.2	58.7%
PPL	$26.1	($11.5)	$30.8	47.4%	$37.7	($21.5)	$103.3	15.7%	$50.5	($7.9)	$41.7	102.1%
PSEG	$24.7	($13.9)	$25.0	43.2%	$35.3	($23.1)	$76.0	16.1%	$34.6	($9.5)	$41.2	61.0%
REC	$0.2	($0.6)	$2.1	(17.0%)	$0.3	($0.8)	$5.3	(9.5%)	$0.3	($0.3)	$1.4	(3.3%)
Total	$524.3	($256.2)	$643.4	41.7%	$637.1	($457.4)	$1,624.6	11.1%	$454.8	($172.3)	$857.5	33.0%

* First four months of the 2022/2023 planning period

Offset if all ARRs are Self Scheduled

Table 13-28 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARR holders self scheduled all their allocated ARRs as FTRs in the 2020/2021, 2021/2022, and 2022/2023 planning period. The calculated self scheduled FTR target allocations assume a 100 percent payout ratio. The results show that the recovery of congestion varies significantly by zone and that the load in some zones recovers more than the congestion paid and the load in other zones recovers less. This result is not consistent with a rational FTR/ARR design under which all load would be returned their congestion, but no more and no less.

Table 13-28 Offset available to load if all ARRs self scheduled: 2020/2021 through 2022/2023 planning periods

	20/21 Planning Period				21/22 Planning Period				22/23 Planning Period*			
	SS FTR	Bal+M2M Charges	Congestion+M2M	Offset	SS FTR	Bal+M2M Charges	Congestion+M2M	Offset	SS FTR	Bal+M2M Charges	Congestion+M2M	Offset
ACEC	$1.8	($2.7)	$5.5	(16.4%)	$0.4	($5.2)	$14.8	(32.2%)	$0.8	($2.4)	$8.7	(17.6%)
AEP	$77.3	($38.1)	$110.9	35.3%	$132.5	($65.7)	$240.4	27.8%	$72.7	($25.2)	$136.1	34.9%
APS	$42.0	($14.8)	$45.2	60.3%	$93.3	($29.7)	$122.8	51.8%	$20.8	($9.8)	$50.4	21.9%
ATSI	$30.7	($19.5)	$50.6	22.1%	$47.3	($32.3)	$117.9	12.7%	$35.2	($13.0)	$66.9	33.2%
BGE	$79.7	($9.1)	$24.8	284.2%	$147.0	($17.0)	$59.9	217.2%	$97.6	($7.3)	$35.7	253.1%
COMED	$69.6	($28.5)	$78.3	52.4%	$51.9	($44.7)	$159.9	4.5%	$10.3	($17.7)	$96.3	(7.7%)
DAY	$8.0	($5.3)	$11.0	24.9%	$7.1	($8.6)	$26.2	(5.6%)	$3.2	($3.6)	$16.7	(2.3%)
DOM	$117.0	($37.9)	$87.9	90.0%	$556.6	($22.0)	$370.9	144.1%	$321.1	($26.5)	$140.2	210.2%
DPL	$56.4	($6.7)	$36.2	137.4%	$52.3	($80.3)	($21.1)	132.8%	$40.3	($4.2)	$23.4	154.1%
DUKE	$40.9	($8.4)	$17.4	187.2%	$50.8	($12.3)	$23.7	162.4%	$29.7	($5.8)	$28.6	83.4%
DUQ	$8.9	($4.0)	$6.2	79.7%	$7.0	($6.4)	$45.3	1.2%	$6.4	($2.8)	$9.1	40.5%
EKPC	$6.6	($4.2)	$8.4	29.3%	$10.1	($7.0)	$21.9	14.2%	$6.0	($2.7)	$12.9	25.7%
EXT	$0.3	($13.8)	$11.0	(122.3%)	$1.9	($9.9)	$19.9	(40.0%)	NA	($5.1)	$14.9	(34.2%)
JCPLC	$0.9	($6.1)	$12.9	(40.2%)	$4.4	($12.8)	$39.0	(21.7%)	$2.4	($5.9)	$25.8	(13.4%)
MEC	$8.0	($5.3)	$16.5	16.5%	$31.3	($11.6)	$33.2	59.5%	$35.2	($4.2)	$15.7	197.5%
OVEC	NA	($0.3)	$0.9	NA	NA	($0.4)	$1.5	(29.4%)	NA	($0.2)	$1.4	(14.1%)
PE	$13.5	($6.5)	$16.4	42.8%	$29.7	($18.5)	$31.8	35.3%	$8.5	($3.4)	$16.4	30.9%
PECO	$14.0	($10.9)	$24.9	12.4%	$6.2	($12.0)	$78.0	(7.5%)	$12.2	$12.2	$41.7	58.6%
PEPCO	$37.3	($8.3)	$20.5	141.7%	$59.2	($15.5)	$53.8	81.2%	$44.4	($6.6)	$32.2	117.2%
PPL	$43.7	($11.5)	$30.8	104.5%	$160.3	($21.5)	$103.3	134.4%	$80.5	($7.9)	$41.7	173.9%
PSEG	$43.2	($13.9)	$25.0	117.0%	$94.0	($23.1)	$76.0	93.2%	$18.8	($9.5)	$41.2	22.5%
REC	$1.0	($0.6)	$2.1	21.0%	$1.1	($0.8)	$5.3	6.2%	$0.2	($0.3)	$1.4	(8.0%)
Total	$700.9	($256.2)	$643.4	69.1%	$1,544.3	($457.4)	$1,624.6	66.9%	$846.4	($151.9)	$857.5	81.0%

* First four months of the 2022/2023 planning period

ARR Allocation and Congestion In and Out of Zone

Table 13-29 shows the share of ARR MW for the first four months of the 2022/2023 planning period with paths that source inside and outside the zone where the ARR load is located, and the proportion of congestion that results from constraints that are inside and outside the zone. Table 13-29 allows a comparison of externally sourced ARRs with the congestion that results from external constraints. For example, 99.3 percent of ACEC congestion results from constraints that are outside of the zone, but only 31.7 percent of ACEC ARRs originate outside the zone.

Table 13-29 illustrates one of the fundamental issues with the path based approach to ARR/FTR design. In the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load, but the assignment of ARRs is inconsistent with that fact. This inconsistency makes it impossible for load to match ARRs with the actual sources of congestion.

Table 13-29 ARR Allocation and Congestion from inside and outside zone: 2022/2023

	ARRs		Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	31.7%	68.3%	99.3%	0.7%
AEP	8.7%	91.3%	87.5%	12.5%
APS	12.6%	87.4%	97.9%	2.1%
ATSI	25.1%	74.9%	99.1%	0.9%
BGE	37.4%	62.6%	84.8%	15.2%
COMED	0.0%	100.0%	91.4%	8.6%
DAY	75.9%	24.1%	99.8%	0.2%
DOM	0.1%	99.9%	48.8%	51.2%
DPL	27.1%	72.9%	51.9%	48.1%
DUKE	34.6%	65.4%	90.1%	9.9%
DUQ	77.7%	22.3%	99.9%	0.1%
EKPC	53.3%	46.7%	99.9%	0.1%
EXT	100.0%	0.0%	81.7%	18.3%
JCPL	17.0%	83.0%	97.5%	2.5%
OVEC	NA	NA	70.1%	29.9%
MEC	41.1%	58.9%	86.2%	13.8%
PE	18.7%	81.3%	94.7%	5.3%
PECO	13.5%	86.5%	80.8%	19.2%
PEPCO	31.6%	68.4%	100.0%	0.0%
PPL	0.1%	99.9%	73.9%	26.1%
PSEG	33.2%	66.8%	99.7%	0.3%
REC	100.0%	0.0%	94.1%	5.9%
Total	17.3%	82.7%	83.2%	16.8%

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. Of the seven defaults not involving Hill Energy Resource & Services, two were promptly cured and the remainder are awaiting resolution. 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 the credit rules to FERC.[41] Under the proposed rules PJM would replace the current credit calculation,

41 *See* "Revisions to PJM's FTR Credit Requirement and Request for 28-Day Comment Period," Docket No. ER22-000 (December 21, 2021).

which is largely based on a weighted average historical FTR value, with an initial margin based on a risk confidence interval from an historical simulation (HSIM) analysis model. PJM's proposal included the use of a 97 percent confidence interval, meaning a 97 percent probability that the initial margin collected would cover potential default costs. The MMU recommends the use of a 99 percent confidence interval when calculating the 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.

On February 28, 2022, FERC rejected PJM's filing recommending a 97 percent confidence interval because the record did not support 97 percent.[42] FERC instituted a Section 206 proceeding, but recognized that PJM could propose revisions through a Section 205 filing.

On June 3, 2022, PJM submitted the same change to the credit rules as the December 21, 2021 filing to FERC.[43] The June 3, 2022 filing includes a cost benefit analysis for the proposed use of a 97 percent confidence interval compared to the use of a 99 percent confidence interval. The MMU continues to recommend the use of a 99 percent confidence interval when calculating the initial margin requirements for FTR market participants.

On August 2, 2022, FERC accepted and suspended PJM's June 3 filing for a nominal period to become effective August 3, 2022, subject to refund and subject to the outcome of newly established paper hearing procedures.

Hill Energy Default

On January 11, 2022, Hill Energy Resource & Services was declared in default for not meeting a collateral call. This default was a result of FTR positions that lost money as a result of the Greys Point – Harmony Village constraint. PJM held $6.1 million in cash collateral from Hill Energy. Due to the timing of the default, January, February, and March 2022, FTRs were settled, while PJM initiated a stakeholder discussion of how to handle the remainder of the portfolio.

42 See 178 FERC¶61,146.

43 *See* "Revisions to PJM's FTR Credit Requirement," Docket No. ER22-000 (June 2, 2022).

PJM decided to liquidate Hill Energy's FTR positions in regularly scheduled FTR auctions, beginning with round 5 of the 2022/2025 Long Term FTR Auction and including the April and May monthly auctions and the 2022/2023 Annual FTR Auction. All of Hill Energy's outstanding FTR positions were liquidated in round 5 of the 2022/2025 Long Term FTR Auction and round 1 of the April 2022 Monthly FTR Auction. Through liquidations and settlements the default cost did not exceed the collateral held by PJM. No costs were distributed to PJM members through the defined default allocation assessment procedures.

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and continues to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends a method under which defaulted FTRs would be canceled rather than holding or liquidating them. Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. But cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

By order issued January 19, 2017, the Commission determined that the FTR forfeiture rule is just and reasonable and "…serves to deter such manipulation" related to virtual transaction cross product manipulation.[44] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: deter manipulation, provide transparency allowing participants to modify their behavior, base forfeitures on an individual participant's actions and is not punitive.[45]

The point of the FTR forfeiture rule is to avoid an inefficient and costly market power mitigation process and to establish an objective rule that prevents manipulation of the FTR market. The FTR forfeiture rule is designed to remove the incentive to engage in manipulation. The rule does not result in findings of manipulation.[46]

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[47] If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the constraint line limit, and that constraint affects an individual FTR's target allocation by $0.01 or more, the participant's net virtual portfolio increased the value of the FTR, and the FTR is subject to FTR forfeiture. The FTR forfeiture also requires that congestion on the FTR path in the day ahead market be greater than congestion on that path in the real time market.

The FTR forfeiture rule does not require FTR holders to pay penalties. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR forfeiture rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule is less effective than initially intended as a result of the element of the rule requiring that day-ahead congestion on the FTR path be greater than real-time congestion the same path. As a result of model differences, there is a significant opportunity for virtual participants to profit from differences between day-ahead and real-time prices without driving the prices together, termed false arbitrage. As a result, FTR holders can use virtual positions to make their FTR positions more valuable without violating the rule.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

On June 24, 2019, PJM implemented a new method to calculate the hourly cost of an FTR only for hours in which it is effective.[48] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the 2020/2021 planning period, total FTR forfeitures were $4.6 million.

On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule.[49] In this order, FERC required PJM to modify the FTR forfeiture rule and submit a compliance filing. As a result, there was no FTR forfeiture rule in place from May 21, 2021 until February 1, 2022. These months have zero forfeiture in Figure 13-14.

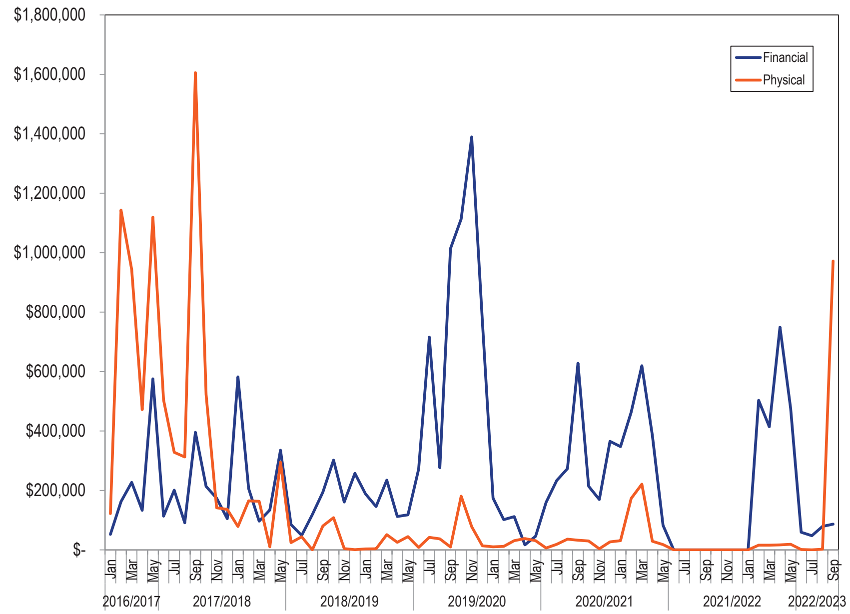
44 See 158 FERC ¶ 61,038 at P 33 (2017).
45 See *id.* at P 62.
46 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).
47 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 State of the Market Report for PJM*, Volume II, Section 13: Financial Transmission Rights for the full history.
48 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).
49 See 175 FERC ¶ 61,137 (2021).

On June 21, 2021, PJM filed a request for clarification, or alternatively rehearing.[50] PJM asked that FERC clarify the status of the forfeitures that were assessed over the four years between the initial FERC order for a compliance filing, and their order rejecting PJM's compliance filing. On July 19, 2021, PJM made a compliance filing to address FERC's concerns with the $0.01 element of the FTR forfeiture rule.[51] PJM's compliance filing eliminated that element and replaced it with a constraint based FTR forfeiture. The forfeiture is based on the increased value of each constraint that violates the rule, determined by the shadow price multiplied by the net dfax on that constraint. This change meets FERC's previously established criteria established under the initial FERC order and creates a more precise FTR forfeiture value, to meet the criteria established under the new FERC order.

On January 31, 2022, FERC accepted PJM's July 19, 2021 compliance filing to implement FTR forfeitures using a constraint based method, effective February 1, 2022.[52]

Figure 13-14 shows the monthly FTR forfeitures under the modified FTR forfeiture rule from January 19, 2017, through January 31, 2022. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures decreased significantly, and stabilized, as participants received information on their FTR forfeitures. Calculations of forfeitures under the new constraint specific rule from February 1, 2022, through September 31, 2022, are included in Figure 13-14.

Figure 13-14 Monthly FTR forfeitures for physical and financial participants



50 *See* "Request for Clarification or, in the Alternative, Rehearing of PJM Interconnection, LLC," FERC Docket No. ER17-1433-00 (June 21, 2021).
51 *See* "FTR Forfeiture Rule Compliance Filing," FERC Docket No. ER17-1433 (July 19, 2021).
52 See 178 FERC ¶61,079.