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 $277.4 million, 61.9 percent, from $448.1 million in 2022 to $170.7 million in 2023, primarily due to a decrease in capacity market prices and revenue. Emergency demand response revenue accounted for 90.0 percent of all demand response revenue, economic demand response for 2.1 percent, demand response in the synchronized reserve market for 3.6 percent and demand response in the regulation market for 4.3 percent.

  Total emergency demand response revenue decreased by $260.2 million, 62.9 percent, from $413.9 million in 2022 to $153.7 million in 2023.[2] This decrease consisted of 86.7 percent of capacity market revenue and 13.3 percent of emergency energy revenue.

  Economic demand response revenue decreased by $7.4 million, 67.5 percent, from $10.9 million in 2022 to $3.5 million in 2023.[3] Demand response revenue in the synchronized reserve market decreased by $8.6 million, 58.1 percent, from $14.9 million in 2022 to $6.2 million in 2023. Demand response revenue in the regulation market decreased by $1.2 million, 14.0 percent, from $8.5 million in 2022 to $7.3 million in 2023.

- **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 2022 and 2023. The HHI for economic resource reductions increased by 1268 points from 7961 in 2022 to 9229 in 2023. The ownership of emergency load response resources is highly concentrated. The HHI for emergency load response committed MW was 2051 for the 2022/2023 Delivery Year. In the 2022/2023 Delivery Year, the four largest CSPs owned 82.8 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2295 for the 2023/2024 Delivery Year. In the 2023/2024 Delivery Year, the four largest CSPs own 85.6 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. Aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.

1 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, and prior to the July 30, 2023 FERC approved revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI), 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 January 8, 2024, 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. 95 (December 14, 2023).

- **Energy Efficiency.** Energy efficiency resources are not capacity resources in PJM. The total MW of energy efficiency resources committed in RPM increased by 30.1 percent in the last capacity market base auction, from 5,896.4 MW in the 2023/2024 Delivery Year to 7,668.7 MW in the 2024/2025 Delivery Year. In the 2024/2025 Delivery Year, although EE is not a capacity resource, EE MW paid in the auction were equal to 5.2 percent of all cleared capacity MW.
- **Energy Efficiency Market Concentration.** The HHI for Energy Efficiency on an aggregate market basis shows that ownership is highly concentrated. The four largest companies typically contribute 90 percent or greater of all committed Energy Efficiency UCAP MW. The HHI for Energy Efficiency resources shows that ownership is highly concentrated for the 2024/2025 Delivery Year, with an HHI value of 5624. In the 2024/2025 Delivery Year, the four largest companies own 98.0 percent of all committed Energy Efficiency UCAP MW.

Recommendations

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. First reported Q1 2023. Status: Not adopted.)
- The MMU recommends that demand resources offering as supply in the capacity market be required to offer a guaranteed load drop (GLD) to ensure that demand resources provide an identifiable MW resource to PJM when called. (Priority: High. First reported Q2 2023. Status: Not adopted.)
- The MMU recommends, as an alternative to including demand resources as supply in the capacity market, that demand resources have the option to 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.[5] (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 and that the same cost verification rules applied to generation resources apply to demand 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. The MMU recommends that demand resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially 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.[6] (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

5 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).

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

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.[7] (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 advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Partially 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.[8])
- 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 the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market

7 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.

8 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.

be eliminated. (Priority: Medium. First reported 2018. Status: Adopted 2022.)

- 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 (EE) 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 2016.)[9]
- 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 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 that excludes multinodal aggregation. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs. (Priority: Medium. First reported Q3 2023. Status: Not adopted.)
- The MMU recommends that PJM revise the requirements for reporting expected real time energy load reductions by CSPs to PJM to improve the accuracy and usefulness to PJM's system operators. (Priority: Medium. First reported Q2 2023. Status: Not adopted.)
- The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. (Priority: Medium. New recommendation. Status: Not 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

9 Originally incorporated with auctions conducted in 2016 for Delivery Years 2016/2017 and forward. The mechanics of the EE addback mechanism were modified beginning with the 2023/2024 Delivery Year.

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. Demand resources do not have telemetry requirements similar to other Capacity Performance resources. Until July 30, 2023, including Elliott, PJM automatically, and inappropriately, triggered a PAI when demand resources are dispatched.

In order to be a substitute for generation, demand resources offering as supply in the capacity market should be required to offer a guaranteed load drop (GLD) to ensure that demand resources provide an identifiable MW resource to PJM when called.

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 demand resources are only obligated to respond for defined time periods meant that PJM could not fully use demand resources during Winter Storm Elliott (Elliott). Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called whenever economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

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

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

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. Compliance of demand resources for capacity purposes during a Performance Assessment Event is measured relative to either Peak Load Contribution or Winter Peak Load, which are static values. If a demand resource's metered load increases above these reference values during a PAI, the current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.[10]

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.

10 See PJM. MC Webinar, Market Monitor Report <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (June 20, 2023).

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 an alternative to being a substitute for generation in the capacity market, demand response resources should have the option to 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, and PJM forecasts would immediately incorporate the impacts of demand side behavior

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.[11] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[12] [13] 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.[14] 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, not limited to a small number of peak hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these 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

11 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>.

12 *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> (March 9, 2018).

13 *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> (April 13, 2018).

14 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).

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.[15] 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.

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response. That is exactly what happened during Elliott.

In concept, Energy Efficiency Resources (EE) reflect investments in measures that improve the energy efficiency of various applications compared to current practices and standards. The original rationale for the inclusion of EE in the PJM Capacity Market was that the load forecasts did not account for the impact of EE on demand for four years. That is no longer true. EE is not actually included in the capacity market. EE is not a capacity resource in PJM. EE does not directly affect the price for capacity in the capacity markets. EE payments are a subsidy paid directly by load via an uplift charge, through the capacity market mechanism. EE should not continue to be paid the capacity market clearing price because PJM's load forecasts now account for EE.[16] Revisions to the PJM load forecast to incorporate energy efficiency were endorsed at the November 19, 2015, MRC with EE explicitly incorporated in PJM load forecasts beginning with auctions conducted in 2016 for the 2016/2017 Delivery Years and forward. Concurrently, PJM began use of an addback method to reflect the inclusion of EE in the peak load forecast. EE is already compensated through the markets to the extent that it actually reduces customer payments for energy and capacity. The removal of EE from the capacity market mechanism would make it unnecessary to address the multiple outstanding issues related to the almost impossible task of accurately measuring the impact of EE, determining the ownership of the imputed savings, and ensuring that the resources are not paid for more than four years. Even if EE were measurable, EE is required to support energy usage reductions for only 416 hours per year, only 4.7 percent of all hours, which is not consistent with the must offer obligations of other capacity resources.

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.[17] 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

15 577 U.S. 260 (2016).

16 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 36 (November 15, 2021).

17 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, and prior to the July 30, 2023 FERC approved revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI), there is no functional difference between the emergency and pre-emergency demand response resource.

regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[18] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits End Use Customers' participation.[19] 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.[20] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

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.[21]

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

18 *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).

19 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.

20 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

21 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 128 (December 14, 2023).

PJM Demand Response Programs

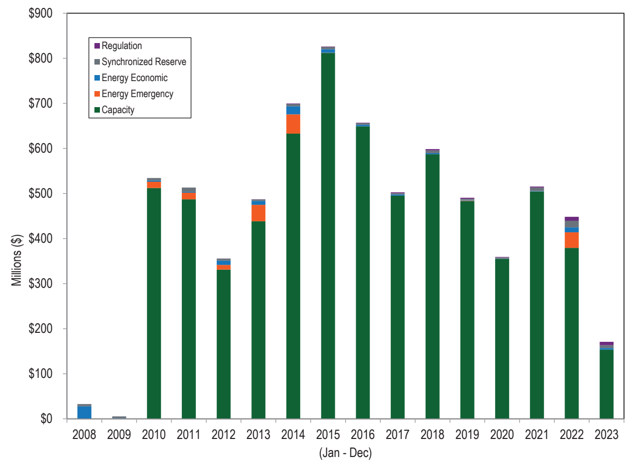
Figure 6-1 shows all revenue from PJM demand response programs by market for each year, 2008 through 2023. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[22] In 2023, total demand response revenue decreased by $277.4 million, 61.9 percent, from $448.1 million in 2022 to $170.7 million in 2023, primarily due to a decrease in capacity market prices and revenue. Total emergency demand response revenue decreased by $260.2 million, 62.9 percent, from $413.9 million in 2022 to $153.7 million in 2023. This decrease consisted 86.7 percent of capacity market revenue and 13.3 percent of emergency energy revenue.[23] In 2023, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 90.0 percent of all revenue received by demand response providers, the economic program for 2.1 percent, synchronized reserve for 3.6 percent and the regulation market for 4.3 percent.

Economic demand response revenue decreased by $7.4 million, 67.5 percent, from $10.9 million in 2022 to $3.5 million in 2023.[24] Demand response revenue in the synchronized reserve market decreased by $8.6 million, 58.1 percent, from $14.9 million in 2022 to $6.2 million in 2023. Demand response revenue in the regulation market decreased by $1.2 million, 14.0 percent, from $8.5 million in 2022 to $7.3 million in 2023.

Lower demand resource revenues in 2023, compared to 2022, are primarily due to capacity market prices and revenues. 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, 64.2 percent lower than the clearing price for the RTO Base Residual Auction for the 2021/2022 Delivery Year. The RTO clearing price for the RPM Base Residual Auction for the 2023/2024 Delivery Year was $34.13 per MW-day, 31.7 percent lower than the clearing price for the RTO Base Residual Auction for the 2022/2023 Delivery Year. The capacity revenue amounts for the first five months of 2022 are from the 2021/2022 Delivery Year and the capacity revenue amounts for the first five months of 2023 are from the 2022/2023 Delivery Year. The capacity revenue amounts for the last seven months of 2022 are from the 2022/2023 Delivery Year and the capacity revenue amounts for the last seven months of 2023 are from the 2023/2024 Delivery Year.

22 This includes both capacity market revenue and emergency energy revenue for capacity resources.
23 The total credits and MWh for demand resources were downloaded as of January 8, 2024, and may change as a result of continued PJM billing updates.
24 Economic credits are synonymous with revenue received for reductions under the economic load response program.

Figure 6-1 Demand response revenue by market: 2008 to 2023



Emergency and Pre-Emergency Load Response Programs

Demand resources participate in the capacity market under the Emergency and Pre-Emergency Load Response Programs. The Pre-Emergency Load Response Program is the default for demand resources. The Emergency Load Response Program is only for resources that use behind the meter generation and that generation has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[25] All demand resources must register as pre-emergency unless the participant qualifies for emergency.

For the first seven months of 2023, PJM declared an emergency if pre-emergency or emergency demand response was dispatched. But in an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI).[26] Under the prior rules, PJM would declare an emergency if pre-emergency or emergency demand response was dispatched. The new rules mean that

25 OA Schedule 1 § 8.5.
26 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).

demand resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[27] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year is determined based solely on a Load Management Test.[28] There are no penalties or consequences for demand response nonperformance.

For example, if a demand resource is called upon five times during the delivery year only outside of Performance Assessment events and fails to perform each time, its delivery year performance will be based only on a Load Management Test. If the Load Management Test is passed, no penalties would be levied even though the resource failed to perform each time it was needed.

The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance.

In all demand response programs, CSPs are companies that sign up End Use Customers that are PJM Members and have the ability to reduce load. CSPs satisfy cleared RPM commitments by registering End Use Customers as Nominated MW.[29] 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.

All emergency or pre-emergency demand resources must 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.[30]

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 does not dispatch DR nodally like other capacity resources. DR can only be dispatched on a zonal or subzonal basis. 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. With the dispatch of DR no longer triggering a PAI, demand resources dispatched outside of a PAI are no longer subject to any event specific penalties or consequences for nonperformance.

Demand resources are not subject to the same rules as other capacity resources related to the definition of response. Increases in load are ignored when calculating the response of DR to a PJM dispatch.

Demand resources are not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer in the capacity market and all other capacity resources must offer their ICAP MW daily in the day-ahead energy market.

The MMU has made recommendations that would provide a capacity market supply side and a demand side option and that would result in treating demand resources in a manner comparable to other capacity and energy resources and in a way that would ensure that the demand side contribution to reliability is accurately measured.

Market Structure

The HHI for demand resources shows that ownership was highly concentrated for the 2022/2023 Delivery Year, with an HHI value of 2051. In the 2022/2023 Delivery Year, the four largest companies contributed 82.8 percent of all committed demand response UCAP MW. The HHI for demand resources shows that ownership is

27 "PJM Manual 18: PJM Capacity Market," § 8.6, Rev. 58 (November 15, 2023).
28 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 58 (November 15, 2023).
29 See RAA Schedule 6. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM has asserted that the reference in RAA Schedule 6 § L.1 and OATT Attachment DD-1 § L.1 to the defined term, "End Use Customer," was a mistake, and proposed to discontinue use of the defined term in the February 8, 2024, meeting of the PJM Governing Document Enhancement and Clarification Subcommittee (GDECS). The proposed change would remove the current requirement in the filed tariff that End Use Customers be PJM Members. The proposed change is substantive and not a correction of a typographical error.
30 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM EPT. *See* PJM OATT RAA Article 1.

highly concentrated for the 2023/2024 Delivery Year, with an HHI value of 2295. In the 2023/2024 Delivery Year, the four largest companies own 85.6 percent of all committed demand response UCAP MW.

Table 6-2 shows the HHI value for committed Demand Response UCAP MW and the market share of the four largest suppliers by delivery year.

Table 6-2 Demand Response HHI: 2019/2020 through 2023/2024 Delivery Years

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	1840	Highly Concentrated	79.1%
2020/2021	2523	Highly Concentrated	88.4%
2021/2022	2070	Highly Concentrated	85.3%
2022/2023	2051	Highly Concentrated	82.8%
2023/2024	2295	Highly Concentrated	85.6%

Table 6-3 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 6-3 HHI value for committed UCAP MW by LDA by delivery year: 2022/2023 and 2023/2024 Delivery Years[31]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
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
2023/2024	ATSI	726.8	2269	High
	ATSI-CLEVELAND	189.4	2919	High
	BGE	168.4	3119	High
	COMED	1,253.2	3363	High
	DAY	209.3	3148	High
	DEOK	175.4	2822	High
	DPL-SOUTH	52.2	4212	High
	EMAAC	651.0	3136	High
	MAAC	508.5	2218	High
	PEPCO	175.2	2154	High
	PPL	583.4	2419	High
	PS-NORTH	126.1	2030	High
	PSEG	146.6	1938	High
	RTO	3,208.6	2342	High

Market Performance

Table 6-4 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 692.1 MW, or 7.8 percent, from 8,866.2 MW in the 2022/2023 Delivery Year to 8,174.1 MW in the 2023/2024 Delivery Year. The DR percent of capacity decreased by 0.4 percentage points, from 5.9 percent in the 2022/2023 Delivery Year to 5.4 percent in the 2023/2024 Delivery Year.

Table 6-4 Cleared Demand Resource UCAP MW: 2007/2008 through 2023/2024 Delivery Years

	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%
2023/2024	8,174.1	150,143.9	5.4%

31 The RTO LDA refers to the rest of RTO.

Table 6-5 shows zonal monthly capacity market revenue to demand resources for 2023. Capacity market revenue decreased in 2023 by $225.6 million, 59.5 percent, from $379.3 million in 2022 to $153.7 million in 2023.

Table 6-5 Zonal monthly demand resource capacity revenue: 2023

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
ACEC	$188,693	$170,433	$188,693	$182,606	$188,693	$81,955	$84,687	$84,687	$81,955	$84,687	$81,956	$84,687	$1,503,735
AEP, EKPC	$2,464,810	$2,226,280	$2,464,810	$2,385,300	$2,464,810	$1,584,486	$1,637,302	$1,637,302	$1,584,486	$1,637,302	$1,584,486	$1,637,302	$23,308,675
APS	$1,036,950	$936,600	$1,036,950	$1,003,500	$1,036,950	$733,317	$757,761	$757,761	$733,317	$757,761	$733,317	$757,761	$10,281,947
ATSI	$1,447,257	$1,307,200	$1,447,257	$1,400,571	$1,447,257	$944,697	$976,187	$976,187	$944,697	$976,187	$944,697	$976,187	$13,788,377
BGE	$639,046	$577,203	$639,046	$618,432	$639,046	$353,388	$365,167	$365,167	$353,388	$365,167	$353,388	$365,167	$5,633,607
COMED	$2,921,684	$2,638,940	$2,921,684	$2,827,436	$2,921,684	$1,131,922	$1,169,652	$1,169,652	$1,131,922	$1,169,652	$1,131,922	$1,169,652	$22,305,801
DAY	$326,275	$294,700	$326,275	$315,750	$326,275	$214,302	$221,445	$221,445	$214,302	$221,445	$214,302	$221,445	$3,117,963
DOM	$1,156,409	$1,044,498	$1,156,409	$1,119,105	$1,156,409	$818,198	$845,472	$845,472	$818,198	$845,472	$818,198	$845,472	$11,469,310
DPL	$467,487	$422,246	$467,487	$452,406	$467,487	$250,143	$258,481	$258,481	$250,143	$258,481	$250,143	$258,481	$4,061,467
DUKE	$411,364	$371,555	$411,364	$398,094	$411,364	$179,592	$185,579	$185,579	$179,592	$185,579	$179,592	$185,579	$3,284,833
DUQ	$230,330	$208,040	$230,330	$222,900	$230,330	$121,025	$125,059	$125,059	$121,025	$125,059	$121,025	$125,059	$1,985,242
JCPLC	$448,375	$404,984	$448,375	$433,911	$448,375	$178,907	$184,870	$184,870	$178,907	$184,870	$178,907	$184,870	$3,460,222
MEC	$685,062	$618,765	$685,062	$662,963	$685,062	$320,993	$331,692	$331,692	$320,992	$331,692	$320,992	$331,692	$5,626,659
PE	$890,253	$804,100	$890,253	$861,536	$890,253	$433,978	$448,444	$448,444	$433,978	$448,444	$433,978	$448,444	$7,432,107
PECO	$1,105,466	$998,485	$1,105,466	$1,069,806	$1,105,466	$561,811	$580,538	$580,538	$561,811	$580,538	$561,811	$580,538	$9,392,275
PEPCO	$470,516	$424,982	$470,516	$455,338	$470,516	$237,849	$245,777	$245,777	$237,849	$245,777	$237,849	$245,777	$3,988,524
PPL	$1,964,912	$1,774,759	$1,964,912	$1,901,527	$1,964,912	$866,174	$895,046	$895,046	$866,174	$895,046	$866,174	$895,046	$15,749,728
PSEG	$893,716	$807,228	$893,716	$864,887	$893,716	$404,878	$418,374	$418,374	$404,878	$418,374	$404,878	$418,374	$7,241,395
REC	$4,854	$4,384	$4,854	$4,697	$4,854	$3,266	$3,375	$3,375	$3,266	$3,375	$3,266	$3,375	$46,942
TOTAL	$17,753,458	$16,035,381	$17,753,458	$17,180,765	$17,753,458	$9,420,882	$9,734,911	$9,734,911	$9,420,882	$9,734,911	$9,420,882	$9,734,911	$153,678,809

Product Definition

Pre-Emergency and Emergency Load Response resources must register all resources with a specific response time. The options are to respond within 30, 60 or 120 minutes of a PJM dispatched event. The 30 minute prior notification is the default and 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.

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2022/2023 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 3,189 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

	Pre-Emergency		Emergency		
Lead Type	MW	Percent	MW	Percent	Total
30 Minutes	4,372.7	95.8%	193.2	4.2%	4,565.9
60 Minutes	353.8	94.4%	21.0	5.6%	374.8
120 Minutes	3,574.1	96.1%	146.9	3.9%	3,721.0
Total	8,300.6	95.8%	361.1	4.2%	8,661.8

	Pre-Emergency		Emergency		
Lead Type	Locations	Percent	Locations	Percent	Total
30 Minutes	13,638	97.3%	384	2.7%	14,022.0
60 Minutes	318	90.1%	35	9.9%	353.0
120 Minutes	2,657	93.7%	179	6.3%	2,836.0
Total	16,613	96.5%	598	3.5%	17,211.0

Table 6-7 shows the amount of nominated MW and locations by product type and lead time for the 2023/2024 Delivery Year. PJM approved 3,224 locations, or 17.5 percent of all locations, which have 3,662.5 nominated MW, or 47.0 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2023/2024 Delivery Year.

Table 6-7 Nominated MW and locations by product type and lead time: 2023/2024 Delivery Year

	Pre-Emergency		Emergency		
Lead Type	MW	Percent	MW	Percent	Total
30 Minutes	3,977.6	96.2%	155.8	3.8%	4,133.4
60 Minutes	374.3	93.0%	28.3	7.0%	402.6
120 Minutes	3,123.4	95.8%	136.5	4.2%	3,259.9
Total	7,475.3	95.9%	320.6	4.1%	7,795.9

	Pre-Emergency		Emergency		
Lead Type	Locations	Percent	Locations	Percent	Total
30 Minutes	14,838	97.9%	311	2.1%	15,149.0
60 Minutes	327	88.9%	41	11.1%	368.0
120 Minutes	2,689	94.2%	167	5.8%	2,856.0
Total	17,854	97.2%	519	2.8%	18,373.0

Table 6-8 Nominated MW and locations of granted lead time exceptions: 2023/2024 Delivery Year

	60 Minutes		120 Minutes		
Reason	MW	Percent	MW	Percent	Total
Generation Start Time	58.4	1.6%	478.0	13.1%	536.4
Manufacturing Damage	220.9	6.0%	1,747.0	47.7%	1,967.9
Safety Problem	123.3	3.4%	1,034.9	28.3%	1,158.3
Total	402.6		3,259.9		3,662.5

	60 Minutes		120 Minutes		
Reason	Locations		Locations		Total
Generation Start Time	74	2.3%	409	12.7%	483
Manufacturing Damage	210	6.5%	748	23.2%	958
Safety Problem	84	2.6%	1,699	52.7%	1,783
Total	368		2,856		3,224

The alternative notification times are 60 minutes and 120 minutes. The CSP must request an exception in writing, including the reason(s) for the requested exception. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year.

The request for an exception must demonstrate one of four defined reasons:[32]

- 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 6-8 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2023/2024 Delivery Year.[33]

There are two ways to measure the 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).[34] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[35] 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.[36] The Winter Peak Load is determined based on the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined five coincident peak days from December through February two delivery years prior to the delivery year for which the registration is submitted.

32 OATT Attachment DD-1, Section A.2(a).
33 Data for generation start time and mass market communication categories were combined based on confidentiality rules.
34 Real-time load is hourly metered load.
35 135 FERC ¶ 61,212 (2011).
36 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 58 (November 15, 2023).

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.[37]

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.[38] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[39] 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 coincident peak load hour, but only 1 MW during the coincident 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 for 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.[40] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

Table 6-9 shows the MW registered by measurement and verification method and by technology type for the 2023/2024 Delivery Year. For the 2023/2024 Delivery Year, 99.99 percent use the FSL method and 0.01 percent use the GLD measurement and verification method.

37 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 58 (November 15, 2023).
38 OATT Attachment DD.5.11.
39 OATT Attachment M-2.
40 162 FERC ¶ 61,159 (2018).

Table 6-9 Nominated MW by each demand response method: 2023/2024 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	1,213.7	1,732.9	189.2	707.9	3,862.0	36.7	52.6	7,795.0	99.99%
Guaranteed Load Drop	0.3	0.5	0.0	0.0	0.1	0.0	0.0	0.9	0.01%
Total	1,214.0	1,733.4	189.2	707.9	3,862.1	36.7	52.6	7,795.9	100.0%
Percent by method	15.6%	22.2%	2.4%	9.1%	49.5%	0.5%	0.7%	100.0%	

Table 6-10 shows the fuel type used in the onsite generators for the 2023/2024 Delivery Year in the emergency and pre-emergency programs. For the 2023/2024 Delivery Year, 1,214.0 MW of the 7,795.9 nominated MW, 15.6 percent, used onsite generation. Of the 1,214.0 MW, 83.9 percent used diesel and 16.1 percent used natural gas, gasoline, oil, propane or waste products. Some DR registrations reflect a participant's reliance on behind the meter generation having environmental restrictions that limit the resource's ability to operate only in emergency conditions. Demand resources relying on behind the meter generation having environmental restrictions limiting the resource's ability to operate only in emergency conditions must register as emergency DR. EPA regulations require that Reciprocating Internal Combustion Engines (RICE) that do not meet EPA emissions standards (stationary emergency 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. 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. PJM's DRHUB does not explicitly identify Reciprocating Internal Combustion Engines (RICE) generators, only whether it is an internal combustion engine. For the 2023/24 Delivery Year, of the 320.6 MW registered as generation backed emergency DR, 316.5 MW are backed by internal combustion engines. Stationary emergency 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.

Table 6-10 Onsite generation fuel type (MW): 2023/2024 Delivery Year

	2023/2024	
Fuel Type	MW	Percent
Diesel	1,018.2	83.9%
Natural Gas, Gasoline, Oil, Propane, Waste Products	195.8	16.1%
Total	1,214.0	100.0%

Table 6-11 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 6-11 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	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,259.6	2,201.9	207.2	760.8	4,160.0	22.2	48.3	8,659.9	99.98%
Guaranteed Load Drop	0.3	1.5	0.0	0.0	0.1	0.0	0.0	1.8	0.02%
Total	1,259.8	2,203.4	207.2	760.8	4,160.1	22.2	48.3	8,661.8	100.0%
Percent by method	14.5%	25.4%	2.4%	8.8%	48.0%	0.3%	0.6%	100.0%	

Table 6-12 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, 1,259.8 MW of the 8,661.8 nominated MW, 14.5 percent, use onsite generation. Of the 1,259.8 MW, 82.8 percent use diesel and 17.2 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-12 Onsite generation fuel type (MW): 2022/2023 Delivery Year

	2022/2023	
Fuel Type	MW	Percent
Diesel	1,043.7	82.8%
Natural Gas, Gasoline, Oil, Propane, Waste Products	216.1	17.2%
Total	1,259.8	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.[41] 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. There are currently seven defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN and AEP_MARION.[42] 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.[43] 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.[44] 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.[45]

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 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. 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

41 OATT Attachment DD, Section 11.

42 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).

43 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>.

44 See the *2018 Annual 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.

45 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 58 (November 15, 2023).

five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[46]

Under the capacity performance design of the capacity market, compliance for potential penalties is measured for DR only during performance assessment intervals (PAI).[47]

The MMU recommended 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. For the first seven months of 2023, PJM declared an emergency if pre-emergency or emergency demand response were dispatched. But in an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI).[48] Table 6-13 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2022/2023 and 2023/2024 Delivery Years. There are 7,478.6 nominated MW of demand response for the 2023/2024 Delivery Year, 40.2 percent of the required reserve margin and 31.4 percent of the actual reserve margin for the 2023/2024 Delivery Year.[49]

Table 6-13 Demand response nominated MW compared to reserve margin: 2022/2023 and 2023/2024 Delivery Years[50]

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
2022/2023	8,129.7	17,990.4	45.2%	24,586.6	33.1%
2023/2024	7,478.6	17,819.3	42.0%	23,809.0	31.4%

PJM will dispatch demand resources by zone or subzone, or within a PAI area. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. In that case, PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or an Emergency Action Area (EAA).[51] [52] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

46 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 58 (November 15, 2023).
47 OATT § 1 (Performance Assessment Hour).
48 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
49 *2022 Annual State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market, Table 5-7.
50 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.
51 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.
52 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 58 (November 15, 2023).

Definition of Compliance

PJM's reporting of load management events overstates the performance of demand side capacity 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 PLC during a demand response event has a negative performance value. But PJM does not include the negative performance values in the net performance calculation. PJM limits reported compliance shortfall values to zero MW.

The MMU recommends that PJM correctly report compliance for demand side capacity resources to include negative values above PLC when calculating event compliance across hours and registrations.[53]

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.[54] 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.[55]

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 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."[56] 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.[57] 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

53 See "Market Monitor Report," MC Webinar <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (Accessed July 6, 2023).

54 157 FERC ¶ 61,067 (2016).

55 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 128 (Dec. 14, 2023).

56 OA Schedule 1 § 8.2.

57 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>.

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.[58]

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 have been inadequate.[59] Prior to the 2023/2024 Delivery Year, the CSP must notify PJM of the intent to test 48 hours in advance of the test. A notification of intent to test was 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 was able to conduct a retest of the subset of registrations in the zone that failed. If the CSP elected to not retest a subset of registrations that failed the test, such registrations maintained the compliance result achieved in the initial test. Retesting had to be performed at the same time of day and under approximately the same weather conditions. Multiple tests could be conducted; however, one test result was submitted for each End Use Customer site in the DR Hub System for compliance evaluation. Test data needed to be submitted on or after June 1st and no later than July 14th after the start of the delivery year.

The ability of CSPs to pick the test time did not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. Given that demand resources are now an annual product, multiple tests are required to ensure reduction capability year round. For the 2023/2024 Delivery Year and subsequent Delivery Years, if a Demand Resource registration is not dispatched by PJM for a Load Management event in a delivery year, then the registration must be tested for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant delivery year, where the date and time are selected by PJM.[60] All registrations in a zone are tested simultaneously for two hours for each product type. Registration performance is calculated as the two hour average reduction. If less than 25 percent (by megawatts) of a CSP's total Demand Resources in a zone fail the test, the CSP may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season, at the same time of day and under approximately the same weather conditions as the prior test. If 25 percent or more (by megawatts) of a CSP's Demand Resources fail the test, the CSP may request PJM to schedule a one-time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test. The request must be made before the 46th day after the test. PJM will select the date and time of the retest during the same season. For the initial PJM scheduled test, PJM schedules, on an alternating basis, one test during June through October or November through March for each delivery year that a test is required. On the first business day of a week, PJM provides notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, PJM posts on its website, and notifies the CSPs directly, the test date and zones.[61] On the test date, CSPs are notified of the start time of the test through the same notification protocol used for an actual event. For any scheduled retest by PJM, by 10:00 EPT the day before the retest, PJM will posts on its website, and notifies the CSPs directly, the retest date. On the retest date, CSPs are notified of the start time of the retest through the same notification protocol used for an event.

While the testing revisions implemented with the 2023/2024 Delivery Year are an improvement, the MMU

58 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.

59 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. 58 (Nov. 15, 2023).

60 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 58 (Nov. 15, 2023).

61 See "Demand Response Test Schedule," <https://pjm.com/markets-and-operations/demand-response/demand-response-test-schedule> (Accessed July 18, 2023).

recommends that load management testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event.

Table 6-14 shows the test penalties by delivery year by product type for the 2018/2019 Delivery Year through the 2022/2023 Delivery Year.[62] 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 0.12 percent of total DR revenues in the 2022/2023 Delivery Year.

Table 6-14 Test penalties by delivery year by product type: 2018/2019 through 2022/2023 Delivery Years

	2018/2019			2019/2020			2020/2021			2021/2022			2022/2023		
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
Limited	0.03	$179.80	$2,100												
Extended Summer															
Annual															
Base DR and EE	16.3	$186.80	$1,110,134	30.2	$154.69	$1,712,177									
Capacity Performance	2.6	$188.55	$178,795				0.9	$125.30	$39,422	23.1	$176.79	$1,487,430	7.1	$97.07	$250,346
Total	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	7.1	$97.07	$250,346

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.[63] There are 97.9 percent of nominated MW for the 2023/2024 Delivery Year registered under the full program option. There are 2.1 percent of nominated MW for the 2023/2024 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."[64] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[65] [66] 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.[67] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources and that the same cost verification rules applied to generation resources apply to demand resources.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[68]

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, had a

62 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.
63 *Id.*
64 161 FERC ¶ 61,153 at P 8 (2017).
65 139 FERC ¶ 61,057 (2012).
66 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.
67 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
68 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 44 (Aug. 1, 2023).

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 had the highest average at $163.21 per location and $132.39 per nominated MW.

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%	$80.65	$51.31
$1,000-$1,275	2,851	16.9%	3,514.7	41.7%	$163.21	$132.39
$1,275-$1,550	352	2.1%	370.9	4.4%	$42.65	$40.48
$1,550-$1,849	13,513	80.3%	4,353.4	51.7%	$41.92	$130.13
Total	16,835	100.0%	8,426.1	100.0%	$62.75	$125.38

Table 6-16 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2023/2024 Delivery Year. The majority of participants, 82.0 percent of locations and 52.3 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2023/2024 Delivery Year. Almost all registrations, 99.5 percent of locations and 98.4 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $108.46 per location and $98.40 per nominated MW.

Table 6-16 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2023/2024 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	84	0.5%	120.6	1.6%	$4.76	$3.32
$1,000-$1,275	2,810	15.5%	3,097.3	40.9%	$108.46	$98.40
$1,275-$1,550	359	2.0%	395.6	5.2%	$4.31	$3.92
$1,550-$1,849	14,845	82.0%	3,957.5	52.3%	$16.00	$60.01
Total	18,098	100.0%	7,571.0	100.0%	$30.07	$71.88

PRD

Price Responsive Demand, or PRD, in the capacity market is capacity based on a firm commitment to 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.[69] Table 6-17 shows the Nominated MW of Price Responsive Demand for the 2020/2021 through 2023/2024 Delivery Years.

Table 6-17 Nominated MW of price responsive demand: 2020/2021 through 2023/2024 Delivery Years

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2023/2024	235.0	235.0	38.0	197.0	15.4	110.0	87.0
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
2020/2021	558.0	558.0	58.0	500.0	27.0	170.0	330.0

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:[70]

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 6-18 shows the PRD Credits for the 2020/2021 through 2023/2024 Delivery Years.[71]

Table 6-18 PRD Credits for 2020/2021 through 2023/2024 Delivery Years

Delivery Year	PRD Credit
2023/2024	$3,776,006.72
2022/2023	$10,702,158.12
2021/2022	$38,282,769.14
2020/2021	$23,649,865.05

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:

$$\begin{aligned} &\mathit{PRD\ Commitment\ Compliance\ Penalty} \\ &\quad = \mathit{MW\ shortfall\ in\ the\ Sub-zone/Zone} \\ &\quad * \mathit{Delivery\ Year\ Forecast\ Pool\ Requirement} \\ &\quad * \mathit{PRD\ Commitment\ Compliance\ Penalty\ Rate} \end{aligned}$$

69 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>.
70 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 58 (Nov. 15, 2023).
71 The total credits for PRD were downloaded as of January 8, 2024, and may change as a result of continued PJM billing updates.

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 ear, 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.

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.[72] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[73] 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.[74]

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 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, 2022, through December 31, 2023. The ownership of economic demand response resources was highly concentrated in 2022 and 2023.[75] 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. The HHI for economic demand response was highly concentrated in 2023. The HHI for economic demand response in 2023 increased by 1268, 15.9 percent, from 7961 in 2022 to 9229 in 2023.

72 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
73 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).
74 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).
75 All HHI calculations in this section are at the parent company level.

Table 6-19 Average hourly MWh HHI and market concentration in the economic program: January 2022 through December 2023[76]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2022	2023	Percent Change	2022	2023	Change in Percent	2022	2023	Change in Percent
Jan	7600	9953	31.0%	99.8%			99.8%		
Feb	7542	8425	11.7%	99.1%	100.0%	0.9%	99.0%	100.0%	1.0%
Mar	8948	9987	11.6%	97.8%	100.0%	2.2%	97.8%	100.0%	2.2%
Apr	7387	9868	33.6%	89.3%	99.7%	10.4%	88.3%	99.9%	11.6%
May	7064	9778	38.4%	96.5%	100.0%	3.5%	96.8%	100.0%	3.2%
Jun	7229	9703	34.2%	92.7%	100.0%	7.3%	93.1%	100.0%	6.9%
Jul	7820	8715	11.4%	95.8%	99.7%	3.9%	94.1%	99.8%	5.7%
Aug	7006	8716	24.4%	94.3%	96.9%	2.7%	87.2%	97.9%	10.7%
Sep	8072	8788	8.9%	99.5%	92.7%	(6.9%)	99.8%	95.2%	(4.6%)
Oct	9400	8958	(4.7%)	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
Nov	8121	8963	10.4%	99.8%	100.0%	0.2%	99.8%	100.0%	0.2%
Dec	7745	9991	29.0%	99.8%			99.7%		
Total	7961	9229	15.9%	95.1%	98.0%	2.9%	93.0%	97.6%	4.6%

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 years 2010 through 2023. The average credits per MWh paid decreased by $41.55 per MWh, 39.5 percent, from $105.10 per MWh in 2022 to $63.55 per MWh in 2023. The average LMP during load response decreased by $37.75 per MWh, 41 percent, from $90.96 per MWh in 2022 to $53.21 per MWh during 2023. Curtailed energy for the economic program was 55,695 MWh in 2023, a decrease of 47,950.2 MWh, 46.3 percent, as compared to curtailed energy for the economic program in 2022. Total credits paid for the economic load response program in 2023 were $3,539,614, a decrease of $7,353,875, 67.5 percent, compared to the total credits paid for the economic load response program in 2022.

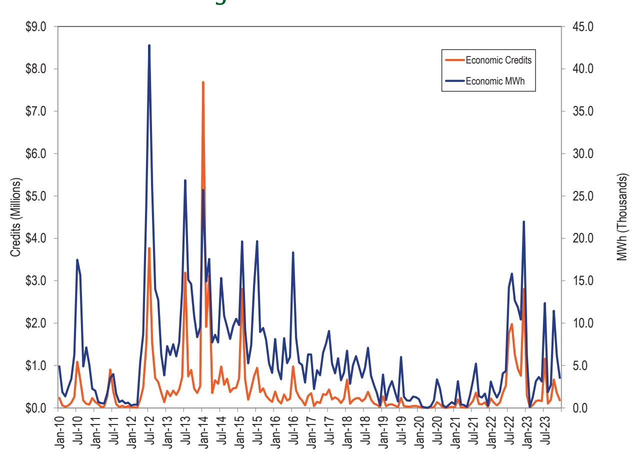
Table 6-20 Credits paid to economic program participants: 2010 through 2023

	Total MWh	Total Credits	$/MWh
2010	72,757	$3,088,049	$42.44
2011	17,398	$2,052,996	$118.00
2012	144,285	$9,278,942	$64.31
2013	133,963	$8,711,873	$65.03
2014	146,301	$17,820,063	$121.80
2015	121,129	$7,983,488	$65.91
2016	81,908	$3,550,535	$43.35
2017	62,622	$2,709,335	$43.27
2018	49,441	$2,548,575	$51.55
2019	24,595	$979,266	$39.82
2020	9,425	$329,119	$34.92
2021	18,851	$1,163,113	$61.70
2022	103,645	$10,893,489	$105.10
2023	55,695	$3,539,614	$63.55

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.[77] For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the day-ahead energy market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[78] 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 December 31, 2023.

Figure 6-2 Economic program credits and MWh by month: 2010 through 2023



76 January and December 2023 reduction and credit share values are not reported based on confidentiality rules.

77 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 128 (Dec. 14, 2023).

78 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

Table 6-21 shows performance for 2022 and 2023 in the economic program by control zone. Total reported reductions under the economic program decreased by 47,950.2 MWh, 46.3 percent, from 103,645 MWh in 2022 to 55,695 MWh in 2023. Total revenue under the economic program decreased by $7.4 million, 67.5 percent, from $10.9 million in 2022 to $3.5 million in 2023.[79]

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.[80] The zonal allocation is shown in Table 6-21.

Table 6-21 Economic program participation by zone: 2022 and 2023

		Credits			MWh Reductions			Credits per MWh Reduction		
Zones	Zones	2022	2023	Percent Change	2022	2023	Percent Change	2022	2023	Percent Change
AECO	ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	AEP	$395,941.94	$209,788.35	(47.0%)	4,404	2,904	(34.1%)	$89.91	$72.25	(19.6%)
APS	APS	$430,657.29	$135,893.56	(68.4%)	3,696	1,710	(53.7%)	$116.52	$79.47	(31.8%)
ATSI	ATSI	$2,054,600.70	$303,827.21	(85.2%)	15,325	1,612	(89.5%)	$134.07	$188.43	40.5%
BGE	BGE	$0.00	$68,182.13	NA	0	892	NA	NA	$76.40	NA
COMED	COMED	$86,827.61	$20,824.42	(76.0%)	1,349	652	(51.7%)	$64.34	$31.96	(50.3%)
DAY	DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DEOK	DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	DUQ	$6,816,954.18	$2,684,988.22	(60.6%)	68,243	46,734	(31.5%)	$99.89	$57.45	(42.5%)
DOM	DOM	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DPL	DPL	$0.00	$49,516.88	NA	0	271	NA	NA	$182.49	NA
JCPL	JCPLC	$68,436.93	$0.00	NA	357	0	NA	$191.70	NA	NA
METED	MEC	$186,518.55	$8,667.10	(95.4%)	1,727	109	(93.7%)	$108.01	$79.86	(26.1%)
OVEC	OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	PECO	$234,339.43	$12,635.23	(94.6%)	2,693	206	(92.3%)	$87.02	$61.28	(29.6%)
PENELEC	PE	$146,945.40	$0.00	NA	1,468	0	NA	$100.11	NA	NA
PEPCO	PEPCO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PPL	PPL	$146,517.74	$30,875.02	(78.9%)	557	394	(29.2%)	$263.07	$78.29	(70.2%)
PSEG	PSEG	$325,748.88	$14,415.63	(95.6%)	3,827	211	(94.5%)	$85.12	$68.32	(19.7%)
REC	REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	Total	$10,893,488.66	$3,539,613.77	(67.5%)	103,645	55,695	(46.3%)	$105.10	$63.55	(39.5%)

79 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-21. Payments for Economic demand response reductions are settled monthly.
80 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 95 (Dec. 14, 2023).

Table 6-22 shows average reported MWh reductions and credits by hour for 2022 and 2023. 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 2022, 77.7 percent of the reported reductions and 78.6 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in 2023, 82.0 percent of the reported reductions and 84.3 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response decreased by $37.75 per MWh, 41 percent, from $90.96 per MWh in 2022 to $53.21 per MWh during 2023.

Table 6-22 Hourly frequency distribution of economic program reported MWh reductions and credits: 2022 and 2023

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2022	2023	Percent Change	2022	2023	Percent Change	2022	2023	Percent Change
1 through 6	6,240	1,256	(80%)	$682,592	$60,770	(91%)	$79.53	$70.18	(12%)
7	3,334	3,122	(6%)	$321,821	$175,343	(46%)	$77.79	$64.76	(17%)
8	3,886	3,645	(6%)	$397,093	$231,890	(42%)	$80.83	$62.21	(23%)
9	4,230	2,043	(52%)	$382,735	$109,990	(71%)	$75.00	$44.82	(40%)
10	4,249	1,214	(71%)	$381,276	$55,414	(85%)	$77.24	$35.26	(54%)
11	4,802	1,311	(73%)	$425,082	$56,446	(87%)	$82.61	$36.24	(56%)
12	5,242	1,361	(74%)	$479,341	$59,193	(88%)	$86.64	$39.52	(54%)
13	5,671	1,201	(79%)	$544,693	$59,105	(89%)	$92.60	$40.72	(56%)
14	6,251	1,755	(72%)	$636,457	$110,706	(83%)	$95.88	$45.64	(52%)
15	6,264	2,734	(56%)	$678,347	$191,545	(72%)	$99.70	$51.27	(49%)
16	6,499	3,954	(39%)	$763,334	$287,804	(62%)	$108.01	$56.80	(47%)
17	7,085	6,052	(15%)	$884,050	$441,829	(50%)	$115.27	$64.52	(44%)
18	7,863	8,084	3%	$987,472	$610,740	(38%)	$114.57	$68.39	(40%)
19	8,105	7,180	(11%)	$915,171	$499,520	(45%)	$101.91	$62.29	(39%)
20	7,643	5,241	(31%)	$817,474	$324,239	(60%)	$95.39	$52.03	(45%)
21	6,603	3,528	(47%)	$671,096	$178,359	(73%)	$92.10	$44.73	(51%)
22	4,880	1,329	(73%)	$480,148	$59,445	(88%)	$85.24	$38.35	(55%)
23 through 24	4,799	685	(86%)	$445,305	$27,276	(94%)	$76.94	$79.99	4%
Total	103,645	55,695	(46%)	$10,893,489	$3,539,614	(68%)	$90.96	$53.21	(41%)

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 2023 and 2022. In 2023, 4.0 percent of reported MWh reductions and 15.8 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): 2022 and 2023

	MWh Reductions			Program Credits		
LMP	2022	2023	Percent Change	2022	2023	Percent Change
$0 to $25	17	157	846%	$190	$1,549	717%
$25 to $50	3,058	24,747	709%	$130,386	$1,068,365	719%
$50 to $75	32,817	22,528	(31%)	$2,079,292	$1,339,312	(36%)
$75 to $100	24,045	4,280	(82%)	$2,147,990	$356,764	(83%)
$100 to $125	21,101	1,124	(95%)	$2,344,322	$131,046	(94%)
$125 to $150	9,867	509	(95%)	$1,383,185	$62,677	(95%)
$150 to $175	4,286	115	(97%)	$720,010	$20,332	(97%)
> $175	8,456	2,236	(74%)	$2,088,114	$559,568	(73%)
Total	103,645	55,695	(46%)	$10,893,489	$3,539,614	(68%)

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. In 2023, DOM Zone has paid the highest Economic Load Response charges.

Table 6-24 Zonal Economic Load Response charge: 2023[81]

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$1,954	$143	$651	$1,242	$511	$1,748	$17,941	$926	$2,819	$4,737	$3,100	$1,291	$37,063
AEP	$34,662	$1,274	$11,309	$28,802	$32,650	$23,899	$159,868	$16,505	$27,646	$111,382	$56,872	$28,403	$533,273
APS	$18,119	$783	$4,841	$11,162	$11,950	$8,844	$63,192	$6,125	$11,216	$42,905	$22,954	$11,817	$213,907
ATSI	$15,268	$593	$5,492	$14,940	$16,490	$12,997	$86,950	$8,486	$15,013	$60,852	$26,386	$13,650	$277,117
BGE	$16,116	$578	$2,885	$5,789	$7,376	$5,957	$46,846	$4,204	$8,196	$26,643	$14,804	$7,587	$146,982
COMED	$13,709	$258	$4,978	$11,586	$22,773	$19,871	$139,065	$13,698	$20,100	$72,590	$26,129	$16,260	$361,017
DAY	$5,342	$202	$1,591	$3,866	$4,507	$3,440	$23,311	$2,465	$3,903	$15,510	$7,696	$4,068	$75,901
DUKE	$6,847	$210	$2,338	$5,833	$7,100	$5,462	$36,087	$3,878	$6,146	$22,702	$11,076	$5,515	$113,194
DUQ	$3,157	$160	$1,038	$2,895	$3,295	$2,614	$19,316	$1,816	$3,317	$11,543	$5,662	$2,718	$57,531
DOM	$41,259	$1,920	$11,085	$27,201	$29,857	$22,245	$165,864	$15,664	$28,984	$107,103	$57,378	$29,788	$538,348
DPL	$4,429	$348	$1,168	$2,311	$719	$2,797	$28,186	$1,635	$4,570	$6,845	$6,008	$4,182	$63,200
EKPC	$4,062	$131	$1,482	$2,952	$3,356	$2,557	$18,535	$1,832	$2,733	$11,844	$6,643	$3,467	$59,597
JCPLC	$3,814	$350	$1,561	$3,135	$1,868	$4,136	$39,954	$2,175	$6,395	$13,568	$7,994	$3,837	$88,788
MEC	$6,248	$284	$1,204	$2,204	$3,541	$2,852	$20,171	$1,292	$3,320	$12,734	$6,709	$3,128	$63,687
OVEC	$36	$1	$11	$27	$24	$16	$103	$11	$20	$101	$52	$26	$429
PECO	$6,195	$663	$2,058	$4,831	$1,570	$5,972	$56,385	$2,231	$9,372	$15,844	$11,632	$4,305	$121,058
PE	$4,356	$218	$1,510	$3,786	$3,767	$2,911	$20,291	$1,878	$3,534	$14,913	$7,656	$3,857	$68,679
PEPCO	$11,201	$432	$2,645	$5,482	$6,912	$5,560	$42,951	$3,881	$7,646	$24,588	$12,993	$6,973	$131,265
PPL	$8,671	$636	$3,239	$6,066	$7,579	$6,963	$49,228	$3,056	$8,202	$31,286	$16,950	$7,789	$149,666
PSEG	$7,069	$670	$2,955	$6,130	$3,287	$7,538	$66,114	$3,633	$10,960	$25,402	$14,925	$6,623	$155,306
REC	$236	$25	$102	$216	$167	$301	$2,614	$166	$438	$1,066	$516	$235	$6,084
Exports	$92,222	$923	$3,398	$8,497	$10,353	$11,726	$58,907	$7,514	$10,975	$35,512	$25,361	$12,136	$277,523
Total	$304,972	$10,804	$67,542	$158,955	$179,656	$160,406	$1,161,881	$103,073	$195,506	$669,671	$349,494	$177,654	$3,539,614

Table 6-25 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in 2023.

Table 6-25 Zonal economic load response charge per GWh of load and exports: 2023

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$2.547	$0.214	$0.938	$2.022	$0.787	$2.178	$14.923	$0.870	$3.225	$6.894	$4.511	$1.673	$3.399
AEP	$3.118	$0.132	$1.085	$3.183	$3.431	$2.436	$14.032	$1.473	$2.829	$11.732	$5.669	$2.629	$4.312
APS	$4.133	$0.204	$1.186	$3.277	$3.404	$2.461	$14.564	$1.474	$3.094	$12.223	$5.910	$2.799	$4.561
ATSI	$2.713	$0.117	$1.010	$3.150	$3.355	$2.497	$14.282	$1.443	$2.900	$12.026	$5.136	$2.517	$4.262
BGE	$6.252	$0.254	$1.224	$2.891	$3.525	$2.538	$15.162	$1.472	$3.371	$12.583	$6.538	$2.985	$4.900
COMED	$1.766	$0.037	$0.683	$1.797	$3.352	$2.584	$15.578	$1.539	$2.755	$10.590	$3.831	$2.211	$3.893
DAY	$3.635	$0.157	$1.139	$3.213	$3.541	$2.549	$14.673	$1.570	$2.939	$12.002	$5.766	$2.904	$4.507
DUKE	$3.118	$0.110	$1.139	$3.199	$3.568	$2.565	$14.220	$1.551	$2.940	$11.978	$5.709	$2.611	$4.392
DUQ	$2.858	$0.165	$0.987	$3.095	$3.298	$2.437	$14.625	$1.471	$3.125	$11.911	$5.665	$2.493	$4.344
DOM	$4.199	$0.223	$1.222	$3.308	$3.486	$2.399	$14.411	$1.421	$3.051	$12.312	$6.241	$2.940	$4.601
DPL	$2.831	$0.251	$0.809	$1.962	$0.588	$1.985	$14.674	$0.927	$3.103	$5.483	$4.368	$2.719	$3.308
EKPC	$3.242	$0.124	$1.333	$3.150	$3.462	$2.523	$15.187	$1.549	$2.766	$12.009	$5.869	$2.716	$4.494
JCPLC	$2.177	$0.225	$0.962	$2.227	$1.261	$2.386	$15.835	$0.995	$3.463	$8.876	$5.048	$2.171	$3.802
MEC	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
OVEC	$2.941	$0.095	$0.974	$2.833	$2.948	$2.000	$11.664	$1.184	$2.209	$10.852	$5.272	$2.355	$3.777
PECO	$1.949	$0.233	$0.684	$1.878	$0.580	$2.008	$14.130	$0.617	$3.025	$5.899	$4.079	$1.363	$3.037
PE	$2.941	$0.165	$1.053	$3.124	$3.051	$2.348	$14.180	$1.340	$2.728	$11.793	$5.759	$2.767	$4.271
PEPCO	$4.799	$0.210	$1.232	$2.893	$3.545	$2.521	$15.004	$1.463	$3.347	$12.391	$6.248	$3.044	$4.725
PPL	$2.402	$0.195	$0.945	$2.149	$2.631	$2.311	$13.355	$0.885	$2.672	$10.657	$5.305	$2.233	$3.812
PSEG	$2.084	$0.220	$0.920	$2.132	$1.103	$2.236	$14.358	$0.885	$3.068	$8.255	$4.782	$1.951	$3.500
REC	$2.199	$0.264	$1.013	$2.271	$1.607	$2.505	$15.990	$1.178	$3.574	$10.292	$5.042	$2.151	$4.007
Exports	$21.361	$0.217	$0.815	$2.524	$2.619	$2.072	$10.978	$1.242	$2.170	$10.489	$6.107	$2.367	$5.247
Monthly Average	$3.785	$0.173	$0.971	$2.558	$2.506	$2.252	$13.719	$1.207	$2.834	$10.057	$5.130	$2.345	$3.961

81 Load response charges were downloaded as of January 8, 2024, and may change as a result of continued PJM billing updates.

Table 6-26 shows the monthly day-ahead and real-time Economic Load Response charges for 2022 and 2023. The day-ahead Economic Load Response charges decreased by $6.3 million, 65.1 percent, from $9.6 million in 2022 to $3.3 million in 2023. The real-time Economic Load Response charges decreased $1.1 million, 84.6 percent, from $1.3 million in 2022 to $0.2 million in 2023.[82]

Table 6-26 Monthly day-ahead and real-time economic load response charge: 2022 through 2023

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2022	2023	Percent Change	2022	2023	Percent Change
Jan	$208,026	$304,451	46.4%	$11,554	$522	(95.5%)
Feb	$59,319	$10,085	(83.0%)	$64,082	$718	(98.9%)
Mar	$17,440	$66,366	280.5%	$41,425	$1,176	(97.2%)
Apr	$100,975	$156,789	55.3%	$30,536	$2,166	(92.9%)
May	$264,451	$175,331	(33.7%)	$92,237	$4,324	(95.3%)
Jun	$247,738	$159,063	(35.8%)	$278,463	$1,342	(99.5%)
Jul	$1,575,419	$1,090,817	(30.8%)	$184,156	$71,063	(61.4%)
Aug	$1,568,733	$90,356	(94.2%)	$410,007	$12,717	(96.9%)
Sep	$1,047,047	$94,311	(91.0%)	$206,547	$101,196	(51.0%)
Oct	$913,625	$660,199	(27.7%)	$4,213	$9,472	124.8%
Nov	$757,985	$348,950	(54.0%)	$2,656	$544	(79.5%)
Dec	$2,797,626	$177,654	(93.6%)	$9,227	$0	(100.0%)
Total	$9,558,385	$3,334,374	(65.1%)	$1,335,103	$205,240	(84.6%)

Table 6-27 shows registered sites and MW for the last day of each month for the period January 1, 2019, through December 31, 2023. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations increased by 81, 24.7 percent, from 328 in 2022 to 409 in 2023. Average monthly registered MW increased by 692 MW, 28.5 percent, from 2,432 MW in 2022 to 3,124 MW in 2023.

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 116 economic registrations and 117 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,342.0 nominated economic MW, 43.0 percent of all economic MW and 1,027.6 nominated capacity MW, 13.2 percent of all nominated capacity MW in the emergency program that share the same location IDs in both programs.

Table 6-27 Economic program registrations on the last day of the month: 2019 through 2023[83]

	2019		2020		2021		2022		2023	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	374	2,651	377	2,909	277	1,495	323	2,233	347	2,874
Feb	370	2,640	382	2,912	275	1,503	323	2,256	354	2,870
Mar	378	2,648	380	2,941	284	1,514	330	2,377	361	2,930
Apr	366	2,594	350	2,917	293	1,538	330	2,382	373	2,932
May	372	3,193	308	2,824	319	1,658	326	2,377	378	3,006
Jun	370	2,768	285	1,418	313	2,136	315	2,323	396	2,929
Jul	376	2,899	283	1,453	312	2,105	310	2,412	412	3,096
Aug	360	2,885	292	1,482	322	2,122	318	2,451	428	3,163
Sep	368	2,954	297	1,566	322	2,256	329	2,565	440	3,335
Oct	375	2,909	275	1,361	332	2,267	333	2,575	453	3,362
Nov	379	3,051	280	1,375	333	2,270	338	2,593	478	3,499
Dec	383	3,070	282	1,327	320	2,256	359	2,640	487	3,493
Avg	373	2,855	316	2,040	309	1,927	328	2,432	409	3,124

82 Load response charges were downloaded as of January 8, 2024, and may change as a result of continued PJM billing updates. Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included. Payments for Economic demand response reductions are settled monthly.

83 Data for years 2010 through 2017 are available in the *2017 Annual State of the Market Report for PJM.*

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, 2011, through December 31, 2023. 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 50.2 MW, 63.7 percent, in 2023 compared to the same months in 2022.[84]

Table 6-28 Sum of maximum MW reported reductions for all registrations per month: 2011 through 2023

	Sum of Peak MW Reductions for all Registrations per Month												
Month	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	132	110	193	446	169	139	123	142	88	28	21	34	50
Feb	89	101	119	307	336	128	83	70	58	11	86	34	18
Mar	81	72	127	369	198	120	111	71	38	12	20	30	53
Apr	80	108	133	146	143	118	54	71	41	3	22	43	70
May	98	143	192	151	161	131	169	70	22	12	9	53	141
Jun	561	954	433	483	833	121	240	105	26	38	125	110	96
Jul	561	1,631	1,088	665	1,362	1,316	936	518	770	135	134	150	309
Aug	161	952	497	358	272	249	141	581	33	99	827	162	191
Sep	84	451	530	795	816	263	140	112	76	31	35	88	392
Oct	81	242	168	214	136	150	88	69	29	9	31	67	80
Nov	86	165	155	166	127	116	81	54	35	12	31	58	88
Dec	88	98	168	155	122	147	83	11	31	14	19	116	61
Annual	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196	921	263	735

Table 6-29 shows total settlements submitted for 2011 through 2023. 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: 2011 through 2023

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Number of Settlements	732	5,835	2,846	3,014	2,173	1,958	1,884	1,524	1,066	520	931	1,793	870

Table 6-30 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the 2011 through 2023. The number of active participants increased by 1, 3.2 percent, from 31 in 2022 to 32 in 2023. All participants must be registered through a CSP.

Table 6-30 Participants and CSPs submitting settlements in the economic program by year: 2011 through 2023

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Active CSPs	15	22	20	18	18	12	13	14	13	11	11	9	8
Active Participants	203	428	276	165	116	58	72	59	53	29	37	31	32

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[85] 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."[86] 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.

84 Maximum MW reductions were downloaded as of January 8, 2024, and may change as a result of continued PJM billing updates.
85 157 FERC ¶ 61,115 at P 139 (2016).
86 *Id.* at 8.

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 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.[87] 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.[88]

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 December 2023. 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 exceeded the lowest historical test result of $34.07 per MWh in 10 of 12 months of 2022. In 2023, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in a single month, January.

87 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 128 (Dec. 14, 2023).

88 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 128 (Dec. 14, 2023).

Table 6-31 Net benefits test threshold prices: August 2010 through December 2023

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)											
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11	$26.93	$40.25
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70	$34.59	$29.79
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82	$30.00	$23.75
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	$23.68
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	$23.43
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	$22.33
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	$22.66
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	$24.89
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	$25.04
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	$55.97	$21.73
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20	$49.57	$23.12
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85	$42.75	$24.43
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	$42.53	$25.42

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.[89] In 2023, the highest zonal LMP in PJM was higher than the NBT threshold price 7,157 hours out of 8,760 hours, or 81.7 percent of all hours. Reductions occurred in 2,800 hours, 39.1 percent, of those 7,157 hours in 2023. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2022, through December 31, 2023. 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 2022, and none of the hours in which LMP was below the NBT threshold price in 2023.

Table 6-32 Hours with price higher than NBT and economic load response occurrences in those hours: 2022 through 2023

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2022	2023	2022	2023	Percent Change	2022	2023	Percentage Change
Jan	744	744	724	458	(36.7%)	70.2%	36.9%	(33.3%)
Feb	672	672	663	412	(37.9%)	47.7%	19.7%	(28.0%)
Mar	743	743	742	678	(8.6%)	55.1%	25.7%	(29.5%)
Apr	720	720	720	664	(7.8%)	66.3%	32.1%	(34.2%)
May	744	744	744	631	(15.2%)	82.9%	37.4%	(45.5%)
Jun	720	720	684	515	(24.7%)	71.1%	51.8%	(19.2%)
Jul	744	744	680	639	(6.0%)	71.3%	51.2%	(20.1%)
Aug	744	744	744	600	(19.4%)	68.4%	59.3%	(9.1%)
Sep	720	720	623	588	(5.6%)	68.7%	48.5%	(20.2%)
Oct	744	744	529	717	35.5%	57.5%	47.4%	(10.0%)
Nov	721	721	569	709	24.6%	48.9%	37.8%	(11.1%)
Dec	744	744	702	546	(22.2%)	69.8%	15.4%	(54.4%)
Total	8,760	8,760	8,124	7,157	(11.9%)	65.3%	39.1%	(26.2%)

89 The MWh for demand resources were downloaded as of January 8, 2024, and may change as a result of continued PJM billing updates.

Energy Efficiency

An EE Resource is required to be a project that involves the installation of more efficient devices or equipment, or the implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section L) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site during the defined EE Performance Hours that is not reflected in the peak load forecast used for the auction delivery year for which the EE Resource is proposed.[90]

On March 26, 2009, FERC approved Tariff and RAA changes to allow EE Resources to participate in PJM Capacity Markets beginning with the Base Residual Auction conducted in May 2009 which committed capacity for the 2012/2013 Delivery Year.[91] FERC approved PJM's request to allow EE Resource participation beginning June 1, 2011 in the remaining 2011/2012 Incremental Auctions by letter order dated January 22, 2010 in Docket No. ER10-366-000. The requirements for Energy Efficiency Resource participation in PJM Capacity Markets are in Tariff, Attachment DD-1 and RAA, Schedule 6, Section L. The only reason that EE was included in the capacity market in the first place was that EE was asserted to not be included in the PJM load forecast used in the capacity market. PJM stated that EE was not fully reflected in the load forecast for four years based on the method in place at the time. As soon as PJM explicitly included EE in the load forecast used in the capacity market, PJM should have followed its tariff language and logic and eliminated EE from the capacity market entirely.

Revisions to the PJM load forecast to incorporate energy efficiency were endorsed at the November 19, 2015, MRC.[92] These revisions included improvements to comprehensively capture energy efficiency impacts through incorporation of projections from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO). The AEO forecast is based on a set of end use models for the residential, commercial, and industrial sectors. EIA accounts for state and utility efficiency programs by mapping regional EE program expenditures to end uses and tracks the number of units sold and associated efficiency information on an ongoing basis.[93]

Instead of eliminating EE from the capacity market consistent with the tariff and logic, PJM removed EE from capacity resource status and implemented a calculation method (the addback method) in the capacity auctions intended to eliminate any price impact of EE on the capacity auctions. Beginning with capacity auctions conducted in 2016 for delivery years 2016/2017 and forward, PJM began use of an addback method to reflect the inclusion of EE in the peak load forecast. PJM documented the addback method in Manual 18 on December 17, 2015, but retained the tariff language that required the complete removal of EE from the capacity market.[94] The current EE addback method, adopted for the 2023/2024 Delivery Year and following an MMU recommendation about how to correct the calculation errors in PJM's implementation of the addback method, uses an iterative approach such that the EE addback MW quantity applied in each capacity auction matches the MW quantity of EE Resources cleared in the auction.[95] The result of the EE addback is that there is no impact on the capacity market clearing price. While EE does not affect the clearing price, customers do pay for the cleared quantity of EE at market clearing prices as an uplift payment or subsidy to EE sellers.

EE is not a capacity resource and is not treated as a capacity resource in the capacity market. EE does not contribute to meeting the RPM Reliability Requirement. EE resources may not serve as a replacement for the commitment of any other RPM Capacity Resource type.

Despite the fact that the EE Resource must be fully implemented at all times during the delivery year, without any requirement of notice, dispatch, or operator intervention, EE accreditation is based only on extremely limited periods both in the required months and the required time period during those months. EE

90 See RAA Schedule 6. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM has asserted that the reference in RAA Schedule 6 § L.1 and OATT Attachment DD-1 § L.1 to the defined term, "End Use Customer," was a mistake, and proposed to discontinue use of the defined term in the February 8, 2024, meeting of the PJM Governing Document Enhancement and Clarification Subcommittee (GDECS). The proposed change would remove the current requirement in the filed tariff that End Use Customers be PJM Members. The proposed change is substantive and not a correction of a typographical error.

91 126 FERC ¶ 61,275 (2009)

92 See *Approved Minutes from the Markets and Reliability Committee*, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20151217/20151217-item-01-draft-minutes-20151119.ashx> (December 17, 2015).

93 See EIA. *Analysis of "Energy Efficiency Program Impacts Based on Program Spending,"* <https://www.eia.gov/analysis/studies/buildings/efficiencyimpacts/pdf/programspending.pdf> (May 2015).

94 PJM. "Manual 18: PJM Capacity Market," § 8.8, Rev. 58 (Nov. 15, 2023).

95 PJM. "Manual 18: PJM Capacity Market," § 2.4.5, Rev. 58 (Nov. 15, 2023).

is required to demonstrate savings only during three summer months and two winter months and only for extremely limited hours during those months. The EE Performance Hours in the summer are defined as the four hours from the hour ending 15:00 Eastern Prevailing Time (EPT) through the hour ending 18:00 EPT during all days for the three month period from June 1 through August 31, inclusive, of such delivery year, that is not a weekend or federal holiday. For the 2023/2024 Delivery Year, the summer EE Performance hours comprise 256 hours across 64 days. The EE Performance Hours in the winter are defined as the four hours from the hour ending 8:00 EPT and hour ending 9:00 EPT, and from the hour ending 19:00 EPT and hour ending 20:00 EPT during all days for the two month period from January 1 through February 28, inclusive, of such delivery year that is not a weekend or federal holiday, For the 2023/2024 Delivery Year, the winter EE Performance hours comprise 160 hours across 40 days. For the 2023/2024 Delivery Year, the total annual EE Performance hours comprised 416 hours across 104 days, or 4.7 percent of all hours in the year.

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 that is metered and tested. The Nominated MW for EE resources are not metered or measured or tested, although they could be, but are based on calculations of estimated savings based on a set of largely unverified and unverifiable assumptions. The Nominated Value of an EE Resource is the expected average demand reduction during the summer EE Performance Hours. Qualifying EE Resources must also have an expected average load reduction during the winter EE performance hours that is not less than the Nominated EE Value determine during the summer EE Performance Hours. If the Nominated EE Value determined during the summer EE Performance hours is greater than the expected average demand during the winter performance hours, the expected demand during the winter performance hours will be the Capacity Performance value of the Capacity Performance EE Resource. The Nominated EE Value of a Summer-Period Energy Efficiency Resource is the expected average demand reduction during the summer EE Performance Hours.

Prescriptive energy efficiency MW are based on and paid on assumed savings calculated based on an assumed installation rate and on 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 are prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement nor 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 or to rely on for the payment of $100 million per year. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.[96]

Most EE MW are not directly measured. Savings are calculated based on an assumed installation rate and assumed usage level, compared to the assumed electricity usage of the default. For example, the calculation of the summer period lighting savings for a residential lighting retrofit is generally:

$\Delta kW = ((WattsBase - WattsEE) / 1000) * ISR * WHFd * CF$

Where:

ISR = In Service Rate approximating percent of bulbs installed in calculation year

WHFd = Waste Heat Factor for Demand to account for cooling savings from efficient lighting

CF = Summer Peak Coincidence Factor approximating percent of EE Performance Hours device is in use

The inputs to these calculations are based on assumptions and observations over very limited periods. Many EE Providers rely on usage assumptions from industry publications rather than from primary data collected from measurements of their own customers. A commonly referenced document in supporting Measurement & Verification reports is the Maryland/Mid-Atlantic Technical Reference Manual (TRM) facilitated and managed by Northeast Energy Efficiency Partnerships, a 501 (c)(3) non-profit organization funded by various advocacy groups and the federal government.[97] [98] While this manual focuses on a geographic region included in PJM's service territory, EE Providers can and do use

96 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 05 (Sep. 21, 2022).
97 See *Maryland/Mid-Atlantic Technical Reference Manual Version 10* <https://neep.org/mid-atlantic-technical-reference-manual-trm-v10> (May 27, 2020).
98 See *Northeast Energy Efficiency Partnership* <https://neep.org/> (March 4, 2024)

assumptions based on installations in locations outside of PJM's service territory. The technical reference manuals (TRM) referenced by EE Providers are often several years old and are unlikely to include the actual current baseline conditions that should be used for valuation of projects. Given the development cycle, the data underlying the TRM lags the publishing date by several years. Of TRMs frequently referenced by EE Providers, the Maryland/Mid-Atlantic TRM was published in 2020, the Pennsylvania TRM in 2021 and the Ohio TRM in 2019. The Pennsylvania PUC updates and approves its TRM on a 5-year cycle.[99] As a result, for the normal three year capacity market timing, a three year old TRM, relying on data from as much as five years prior to publication, is used to estimate savings for at least four years into the future.

The benefits of EE measures decline over time as energy saving technology is adopted by customers. This decreases the baseline against which savings should be measured and, over time, should reduce the assumed savings associated with project installations. An example of a decreasing baseline is in residential lighting. The assumed baseline condition was originally an incandescent bulb but should have evolved to LED, which eliminates the incremental savings when replaced by another LED lightbulb.

The mix of EE project types offered into RPM should have more quickly reflected the actual technology adopted in the markets. In the 2020/2021 BRA, lighting projects comprised 74 percent of all EE measures. In the 2024/2025 BRA, lighting dropped to 45 percent of all EE measures. Building envelope measures, which include thermal performance improvements to exterior walls, windows, doors, and roofing to reduce building energy consumption are a growing project type encompassing 35 percent of all EE measures in the 2024/2025 BRA.

There is no evidence that the EE programs result in changed behavior or increases in savings. EE Providers may repackage the independent actions of customers that have already occurred. There is no evidence that EE participation in PJM markets causes End Use Customers to reduce their energy consumption beyond what they would have otherwise.

The MMU recommends that Energy Efficiency Resources (EE) be removed from the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[100] EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets because to the extent that it actually reduces energy and capacity use, it reduces 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 quantity of EE at market clearing prices. These direct payments to EE in the capacity market are an overpayment by customers. Table 6-33 shows the RPM revenues paid, by delivery year, to energy efficiency (EE) resources in PJM.

PJM does not codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff. PJM does not have 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.

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.[101] This demonstration is generally a prepackaged statement, provided by PJM, that is never fully verified. 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. These eligibility requirements should specifically define the conditions under which an Energy Efficiency Resource Provider may claim the capacity rights to

99 66 PA § 2806.1(c)(3)

100 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 36 (Nov. 15, 2023).

101 PJM. EE Post-Installation Measurement & Verification Report Template, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/post-installation-measurement-and-verification.ashx> (*Accessed Aug. 5, 2022*).

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 paid in the capacity market as of on June 1 for the 2011/2012 through 2023/2024 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[102] Only Kentucky has been authorized by the Commission.[103] The total MW of energy efficiency resources committed increased by 30.1 percent in the last capacity market base auction, from 5,896.4 MW in the 2023/2024 Delivery Year to 7,668.7 MW in the 2024/2025 Delivery Year.[104]

Table 6-33 Energy efficiency resources (MW): 2011/2012 through 2023/2024 Delivery Years

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE MW/ Capacity MW	EE RPM Revenue
2011/2012	76.4	134,139.6	0.1%	$139,812
2012/2013	666.1	141,061.8	0.5%	$11,408,552
2013/2014	904.2	159,830.5	0.6%	$21,598,174
2014/2015	1,077.7	161,092.4	0.7%	$42,308,549
2015/2016	1,189.6	173,487.4	0.7%	$66,652,986
2016/2017	1,723.2	179,749.0	1.0%	$68,709,670
2017/2018	1,922.3	180,590.3	1.1%	$86,147,605
2018/2019	2,296.3	175,957.4	1.3%	$103,105,796
2019/2020	2,528.5	177,040.6	1.4%	$92,569,666
2020/2021	3,569.5	173,688.5	2.1%	$101,348,169
2021/2022	4,806.2	174,713.0	2.8%	$185,755,803
2022/2023	5,734.8	150,465.2	3.8%	$135,265,303
2023/2024	5,896.4	150,143.9	3.9%	$93,603,058
2024/2025	7,668.7	147,505.6	5.2%	$117,133,991

The ownership of Energy Efficiency is highly concentrated. The combined market share of the four largest companies ranges from 90 to 99 percent of all committed Energy Efficiency UCAP MW. The HHI for Energy Efficiency resources shows that ownership of EE for the entire market is highly concentrated for each of the last six Delivery Years. Table 6-34 shows the HHI value for committed Energy Efficiency UCAP MW and the market share of the four largest suppliers by delivery year for the entire market.

102 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).
103 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).
104 See the *2021Annual State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

Table 6-34 Energy Efficiency HHI: 2019/2020 through 2024/2025 Delivery Year

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	3574	Highly Concentrated	90.6%
2020/2021	3005	Highly Concentrated	89.8%
2021/2022	3409	Highly Concentrated	91.6%
2022/2023	5803	Highly Concentrated	99.1%
2023/2024	6209	Highly Concentrated	99.9%
2024/2025	5624	Highly Concentrated	98.0%

The ownership of Energy Efficiency is also highly concentrated on an LDA basis as shown by the HHI levels. The individual LDA HHI values cannot be made public based on PJM's confidentiality rules. Table 6-35 shows the HHI value for committed UCAP MW by LDA for the 2023/2024 and 2024/2025 Delivery Years.

Table 6-35 Energy Efficiency HHI by LDA

	Structure	
LDA	2023/2024	2024/2025
ATSI	Highly Concentrated	Highly Concentrated
ATSI-CLEVELAND	Highly Concentrated	Highly Concentrated
BGE	Highly Concentrated	Highly Concentrated
COMED	Highly Concentrated	Highly Concentrated
DAY	Highly Concentrated	Highly Concentrated
DEOK	Highly Concentrated	Highly Concentrated
DPL-SOUTH	Highly Concentrated	Highly Concentrated
EMAAC	Highly Concentrated	Highly Concentrated
MAAC	Highly Concentrated	Highly Concentrated
PEPCO	Highly Concentrated	Highly Concentrated
PPL	Highly Concentrated	Highly Concentrated
PS-NORTH	Highly Concentrated	Highly Concentrated
PSEG	Highly Concentrated	Highly Concentrated
RTO	Highly Concentrated	Highly Concentrated

Table 6-36 shows how EE MW are distributed across LDAs. For example, 15.1 percent of all EE MW were in EMAAC in the 2024/2025 Delivery Year.

Table 6-36 Energy Efficiency Cleared UCAP Percentage by LDA

	Percent of EE	
LDA	2023/2024	2024/2025
ATSI	6.9%	6.9%
ATSI-CLEVELAND	0.8%	0.7%
BGE	4.6%	5.0%
COMED	16.3%	13.9%
DAY	1.7%	1.7%
DEOK	2.8%	2.5%
DPL-SOUTH	1.0%	1.3%
EMAAC	14.2%	15.1%
MAAC	3.8%	3.9%
PEPCO	5.1%	5.2%
PPL	5.2%	5.1%
PS-NORTH	3.6%	4.9%
PSEG	4.0%	5.2%
RTO	30.2%	28.7%

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.[105] 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.[106] 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.

Distributed Energy Resources

Distributed Energy Resources (DER) include generation connected to distribution level facilities, behind the meter generation, and energy storage facilities connected to the distribution grid or to load. 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, but larger resources, up to 5 MW, can participate.[107] Order No. 2222 does not require aggregation across nodes rather than aggregation behind individual nodes or aggregation for settlement purposes. The DER rules in the PJM markets will become effective for the 2026/2027 Delivery Year.

During 2023, PJM continued to develop rules in the stakeholder process and to submit compliance filings to FERC.[108] On March 1, 2023, FERC issued an order and directed PJM to make a further compliance filing.[109] PJM submitted a filing on September 1, 2023, in compliance with the Order No. 2222 and the March 1st Order ("September 1st Filing"). The directives in the March 1st Order include removing an exemption of DER Capacity Aggregation Resources that include component DERs that are co-located with retail end use load from the capacity market power mitigation rules,[110] clarifying rules around the resources that both curtail load and inject energy, removing automatic approval for net energy metering resources' participation in the ancillary services market, clarifying the definition of double counting, reconsidering single node aggregation in the energy market, removing the proposed pre-registration process and specifying utility review criteria.

In the September 1st Filing, PJM proposes to allow double payment of net energy metering resources and multinodal aggregation for small resources, fails to clarify rules for DER with the ability to both curtail load and inject power, and fails to include provisions for market monitoring of component DER and host EDCs.

Getting the rules right 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 undermines 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 not structurally competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. The March 1st Order does

105 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).
106 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 36 (Nov. 145, 2023).
107 172 FERC ¶ 61,247 at PP 6–7 (2020).
108 *See* FERC Docket No. ER22-962.
109 182 FERC ¶ 61,143 ("March 1st Order").
110 *See* FERC Docket Nos. ER22-962-001 and ER22-962-002.

not prevent EDCs from serving as DER aggregators or address the market power issues, based on a reference to the provision of Order No. 2222 that prohibits RTOs/ISOs from limiting the business models under which DER aggregators can operate.

The September 1st Filing states that PJM will not interrupt or interfere with the EDC's decisions to override the market dispatch of DERs, decisions which could involve the exercise of market power. Neither the March 1st Order nor the September 1st Filing define the MMU's role in mitigating the potential exercise of market power by EDCs. In order to permit efficient and effective market monitoring, EDCs and DERAs should be explicitly required to provide information requested by the MMU requests from them. The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs.

The March 1st Order stated that the Commission could revisit the EDCs' role in the PJM markets, if FERC discovers "evidence of undue discrimination regarding the participation of DER aggregations in RTO/ISO markets."[111] The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. EDCs have a very significant role to play as designers, builders and managers of the local grids, without competing with DER providers.

The PJM market is a nodal market. Nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Aggregation behind a single node is feasible, is consistent with the nodal market principle, and will encourage competition. Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed. The March 1st Order asked PJM to explore an option to allow broader aggregation where technically feasible by identifying areas with historically minimal congestion. It is, however, impossible to know when constraints will bind ahead of time. Constraints are dynamic and often simultaneous. Even if one could identify a group of pricing nodes that do not have an impact on a particular constraint, it is very likely that they have an impact on another constraint. Even if that group of pricing nodes does not have impact on any constraint at one point in time, it is very likely that they will have an impact on a constraint (or multiple constraints) at another time. In response to FERC, the September 1st Filing proposes to allow multinodal aggregation only for small resources that meet defined conditions. The MMU recommends that the Commission require PJM to use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation.

Under the proposed DER rules, special advantages provided to resources that participate in the DER aggregation model include: exemption from the PJM interconnection process; exemption from the must offer requirement in the capacity market; and the 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. The March 1st Order accepted PJM's proposed maximum size requirement of 5.0 MW for component DERs but did not require PJM to propose a maximum size requirement for DER Aggregation Resources. 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 DER Aggregation Resource. The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations.

DERs should not be exempt from market power mitigation. Small resources can and do have market power and can and do exercise 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 March 1st Order accepted PJM's proposal to require DER aggregation resources to submit cost-based offers but failed to address offer parameter mitigation. The absence of consistently applied market power mitigation rules across resource types creates the potential for the exercise of market power and noncompetitive market outcomes as well as incentives to participate in ways designed to avoid market power mitigation rules.

111 The March 1st Order at P 334.

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 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 March 1st Order directed PJM to remove the automatic approval for net energy metering resources participation in the ancillary services market because certain state net metering tariffs currently include compensation for ancillary services. The September 1st Filing clarifies that EDCs can reject the resource during the utility review period based on double counting concern. However, it proposes to change the definition of double counting from being "credited" for the same service to "providing" the same service through an existing retail program. The September 1st Filing further states that PJM is not aware of any retail program in the PJM footprint that permits Component DER to actually "provide" ancillary services at this time.[112] This means all Component DERs that are credited at a full retail rate including compensation for ancillary services will be able to participate in the PJM ancillary services markets even though they are already paid for the service. If the net energy metering resources receive credits at a rate that includes compensation for ancillary services, it should be assumed that they provide the service.

112 The September 1st Filing at 15.