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 $103.3 million, 66.1 percent, from $156.4 million in the first three months of 2022 to $53.1 million in the first three months of 2023. Emergency demand response revenue accounted for 97.1 percent of all demand response revenue, economic demand response for 0.6 percent, demand response in the synchronized reserve market for 0.5 percent and demand response in the regulation market for 1.8 percent.

  Total emergency demand response revenue decreased by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023.[2] This decrease consisted of capacity market revenue.

  Economic demand response revenue decreased by $0.1 million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[3] Demand response revenue in the synchronized reserve market decreased by $1.6 million, 85.7 percent, from $1.9 million in the first three months of 2022 to $0.3 million in the first three months of 2023. Demand response revenue in the regulation market decreased by $0.1 million, 13.3 percent, from $1.0 million in the first three months of 2022 to $0.9 million in the first three months of 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 the first three months of 2022 and the first three months of 2023. The HHI for economic resource reductions increased by 1528 points from 7861 in the first two months of 2022 to 9459 in the first two months of 2023. The ownership of emergency load response resources is highly concentrated. The HHI for emergency load response committed MW was 2070 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs owned 85.3 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2051 for the 2022/2023 Delivery Year. In the 2022/2023 Delivery Year, the four largest CSPs own 82.8 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Aggregation rules allow a

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

2 The total credits and MWh numbers for demand resources were downloaded as of April 6, 2023 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. 90 (Jan. 25, 2023).

demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

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. New recommendation. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. The MMU recommends that demand resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values

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

be 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.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)

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

- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with 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 be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources not be included in the capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. (Priority: Medium. First reported 2022. Status: Not adopted.)

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

- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets. (Priority: Medium. First reported 2022. Status: Partially adopted.)

Conclusion

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

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

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

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that 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). The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called 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. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, Actual Performance of demand resources during a Performance Assessment Event should be determined consistent with that of generation and should not be netted across the Emergency Action Area (EAA). The Capacity Market Seller's Performance Shortfalls for Demand Resources in the EAA are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's demand resources that under complied within the EAA on a prorata basis based on the under compliance MW, and such seller's demand resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over complied within the EAA on a prorata basis based on over compliance MW, and such Market Seller's Demand Resources will be assessed Bonus Performance. Netting of performance of Demand Resources across the EAA is inconsistent with the performance measurement of other Capacity Performance resources.

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

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

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[8] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's

8 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.
9 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed April 28, 2022).
10 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed April 28, 2022).

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.[11] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours, 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.

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

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

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side.[12] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

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.

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.

12 577 U.S. 260 (2016).

Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participate in the capacity market and energy market.[13] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

FERC Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[14] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits end use customers' participation.[15] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to provide additional verification.[16] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)			Economic Demand Response	
Product Types	Capacity Performance, Summer-Period Capacity Performance OATT Attachmend DD § 5.5A	Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachemnt K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	RPM event RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

13 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.
14 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
15 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.
16 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania (e.g. Pennsylvania ACT 129 Utility Program) and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.[17]

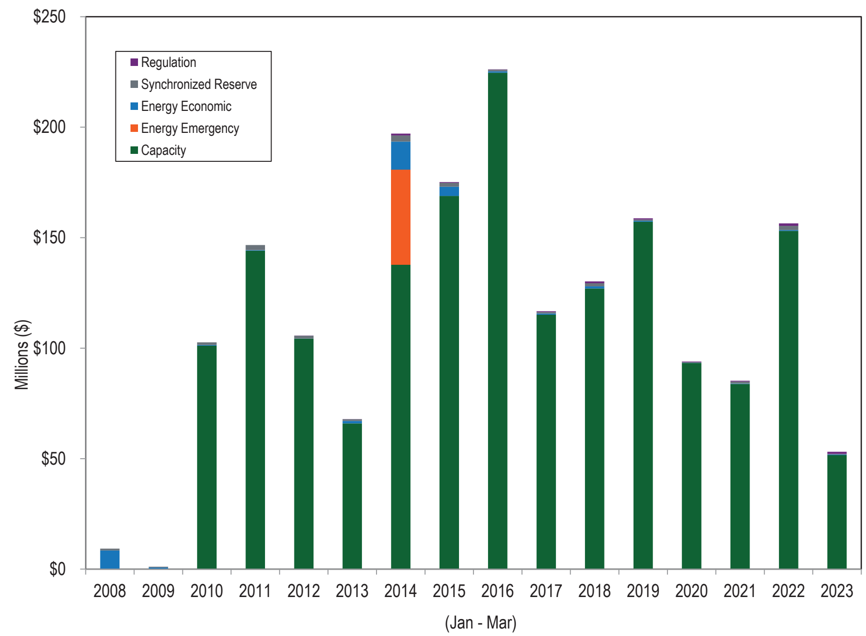
PJM Demand Response Programs

Figure 6-1 shows all revenue from PJM demand response programs by market for 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.[18] In the first three months of 2023, total demand response revenue decreased by $103.3 million, 66.1 percent, from $156.4 million in the first three months of 2022 to $53.1 million in the first three months of 2023. Total emergency demand response revenue decreased by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023. This decrease consisted of capacity market revenue.[19] In the first three months of 2023, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 97.1 percent of all revenue received by demand response providers, the economic program for 0.6 percent, synchronized reserve for 0.5 percent and the regulation market for 1.8 percent.

Economic demand response revenue decreased by $0.1million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[20] Demand response revenue in the synchronized reserve market decreased by $1.6 million, 85.7 percent, from $1.9 million in the first three months of 2022 to $0.3 million in the first three months of 2023. Demand response revenue in the regulation market decreased by $0.1 million, 13.3 percent, from $1.0 million in the first three months of 2022 to $0.9 million in the first three months of 2023.

Lower demand resource revenues in the first three months of 2023, compared to 2022, are primarily due to capacity market 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 capacity revenue amounts for the first three months of 2022 are from the 2021/2022 Delivery Year and the capacity revenue amounts for the first three months of 2023 are from the 2022/2023 Delivery Year.

Figure 6-1 Demand response revenue by market: January through March, 2008 through 2023



17 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 123 (Feb. 9, 2023).
18 This includes both capacity market revenue and emergency energy revenue for capacity resources.
19 The total credits and MWh for demand resources were downloaded as of April 6, 2023 and may change as a result of continued PJM billing updates.
20 Economic credits are synonymous with revenue received for reductions under the economic load response program.

Emergency and Pre-Emergency Load Response Programs

Demand resources participate in the capacity market within the Emergency and Pre-Emergency Load Response Programs.

All demand resources must register as pre-emergency unless the participant relies on behind the meter generation and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[21] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. CSPs satsify cleared RPM commitments registerting customers as Nominated MW. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

The emergency and pre-emergency load response programs consist of the base and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year requires all emergency or pre-emergency demand resources to be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[22]

All capacity performance resource types must respond during a Performance Assessment Interval (PAI). Demand resources are the only capacity performance resource types that trigger a PAI when dispatched by PJM. PJM eliminated any substantive difference between pre-emergency and emergency by making the dispatch of either type trigger a PAI.

The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. Demand resources are not required to meet the same requirements as other capacity resources for the PAI.

Demand resources are also not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer daily into the day-ahead energy market.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the day-ahead energy market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends eliminating the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[23]

Market Structure

The HHI for demand resources showed that ownership was highly concentrated for the 2021/2022 Delivery Year, with an HHI value of 2070. In the 2021/2022 Delivery Year, the four largest companies contributed 85.3 percent of all committed demand resources UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2022/2023 Delivery Year, with an HHI value of 2051. In the 2022/2023 Delivery Year, the four largest companies own 82.8 percent of all committed demand response UCAP MW.

21 OA Schedule 1 § 8.5.
22 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM EPT. *See* PJM OATT RAA Article 1.
23 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-2 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-2 HHI value for committed UCAP MW by LDA by delivery year: 2021/2022 and 2022/2023 Delivery Years[24]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2021/2022	ATSI	924.0	2212	High
	ATSI-CLEVELAND	272.8	4800	High
	BGE	279.0	2171	High
	COMED	2,073.7	2492	High
	DAY	227.7	2748	High
	DEOK	220.5	2131	High
	DPL-SOUTH	66.3	4622	High
	EMAAC	904.7	1852	High
	MAAC	750.0	1868	High
	PEPCO	345.9	1995	High
	PPL	697.7	2034	High
	PS-NORTH	188.6	2184	High
	PSEG	221.9	1835	High
	RTO	4,254.9	2462	High
2022/2023	ATSI	757.6	2267	High
	ATSI-CLEVELAND	191.8	2589	High
	BGE	163.9	3049	High
	COMED	1,521.9	2515	High
	DAY	210.5	2709	High
	DEOK	185.1	2354	High
	DPL-SOUTH	48.4	4936	High
	EMAAC	796.9	2157	High
	MAAC	530.5	2185	High
	PEPCO	325.3	3163	High
	PPL	661.7	2143	High
	PS-NORTH	93.8	2613	High
	PSEG	200.8	2060	High
	RTO	3,178.0	2247	High

Market Performance

Table 6-3 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 2,561.5 MW, or 22.4 percent, from 11,427.7 MW in the 2021/2022 Delivery Year to 8,866.2 MW in the 2022/2023 Delivery Year. The DR percent of capacity decreased by 0.6 percentage points, from 6.5 percent in the 2021/2022 Delivery Year to 5.9 percent in the 2022/2023 Delivery Year.

Table 6-3 Cleared Demand Resource UCAP MW: 2007/2008 through 2022/2023 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,139.6	1.4%
2012/2013	8,740.9	141,061.8	6.2%
2013/2014	10,779.6	159,830.5	6.7%
2014/2015	14,943.0	161,092.4	9.3%
2015/2016	15,453.7	173,487.4	8.9%
2016/2017	13,265.3	179,749.0	7.4%
2017/2018	11,870.5	180,590.3	6.6%
2018/2019	11,435.4	175,957.4	6.5%
2019/2020	10,703.1	177,040.6	6.0%
2020/2021	9,445.7	173,688.5	5.4%
2021/2022	11,427.7	174,713.0	6.5%
2022/2023	8,866.2	150,465.2	5.9%

Table 6-4 shows zonal monthly capacity market revenue to demand resources for January through March 2023. Capacity market revenue decreased in the first three months of 2023 by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023. 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 capacity revenue amounts for the first three months of 2022 are from the 2021/2022 Delivery Year and the capacity revenue amounts for the first three months of 2023 are from the 2022/2023 Delivery Year.

24 The RTO LDA refers to the rest of RTO.

Table 6-4 Zonal monthly demand resource capacity revenue: January through March, 2023

Zone	January	February	March	Total
ACEC	$188,693	$170,433	$188,693	$547,819
AEP, EKPC	$2,464,810	$2,226,280	$2,464,810	$7,155,900
APS	$1,036,950	$936,600	$1,036,950	$3,010,500
ATSI	$1,447,257	$1,307,200	$1,447,257	$4,201,713
BGE	$639,046	$577,203	$639,046	$1,855,296
COMED	$2,921,684	$2,638,940	$2,921,684	$8,482,307
DAY	$326,275	$294,700	$326,275	$947,250
DOM	$1,156,409	$1,044,498	$1,156,409	$3,357,315
DPL	$467,487	$422,246	$467,487	$1,357,219
DUKE	$411,364	$371,555	$411,364	$1,194,283
DUQ	$230,330	$208,040	$230,330	$668,700
JCPLC	$448,375	$404,984	$448,375	$1,301,734
MEC	$685,062	$618,765	$685,062	$1,988,888
PE	$890,253	$804,100	$890,253	$2,584,607
PECO	$1,105,466	$998,485	$1,105,466	$3,209,417
PEPCO	$470,516	$424,982	$470,516	$1,366,014
PPL	$1,964,912	$1,774,759	$1,964,912	$5,704,583
PSEG	$893,716	$807,228	$893,716	$2,594,660
REC	$4,854	$4,384	$4,854	$14,091
TOTAL	$17,753,458	$16,035,381	$17,753,458	$51,542,296

Product Definition

Pre-Emergency and Emergency Load Response resources must register all resources to respond within 30, 60 or 120 minutes of a PJM dispatched event. This default 30 minute prior notification applies unless a CSP obtains an exception from PJM due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe.

Table 6-5 shows the amount of nominated MW and locations by product type and lead time for the 2021/2022 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 3,213 locations, or 20.9 percent of all locations, which have 3,645.6 nominated MW, or 45.8 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2021/2022 Delivery Year.

Table 6-5 Nominated MW and locations by product type and lead time: 2021/2022 Delivery Year

Lead Type	Pre-Emergency MW	Emergency MW	Total
Quick Lead (30 Minutes)	4,114.1	203.8	4,317.9
Short Lead (60 Minutes)	285.5	21.0	306.5
Long Lead (120 Minutes)	3,198.2	140.8	3,339.1
Total	7,597.9	365.7	7,963.5
Lead Type	**Pre-Emergency Locations**	**Emergency Locations**	**Total**
Quick Lead (30 Minutes)	11,702	444	12,146.0
Short Lead (60 Minutes)	331	37	368.0
Long Lead (120 Minutes)	2,658	187	2,845.0
Total	14,691	668	15,359.0

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2022/2023 Delivery Year. PJM approved 3,192 locations, or 18.5 percent of all locations, which have 4,095.8 nominated MW, or 47.3 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2022/2023 Delivery Year.

Table 6-6 Nominated MW and locations by product type and lead time: 2022/2023 Delivery Year

Lead Type	Pre-Emergency MW	Emergency MW	Total
Quick Lead (30 Minutes)	4,374.2	191.7	4,565.9
Short Lead (60 Minutes)	353.8	21.0	374.8
Long Lead (120 Minutes)	3,574.1	146.9	3,721.0
Total	8,302.2	359.6	8,661.8
Lead Type	**Pre-Emergency Locations**	**Emergency Locations**	**Total**
Quick Lead (30 Minutes)	13,642	389	14,031.0
Short Lead (60 Minutes)	317	36	353.0
Long Lead (120 Minutes)	2,657	182	2,839.0
Total	16,616	607	17,223.0

The only alternative notification times that PJM will permit are 60 minutes and 120 minutes. The CSP must submit in writing that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. 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:[25]

- The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- Transfer of load to backup generation requires time intensive manual process taking more than 30 minutes;
- Onsite safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within 30 minutes due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

Table 6-7 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2022/2023 Delivery Year.[26]

Table 6-7 Nominated MW and locations of granted lead time exceptions: 2022/2023 Delivery Year

	Short Lead (60 Minutes)	Long Lead (120 Minutes)	
Reason	MW	MW	Total
Generation Start Time	53.9	816.1	870.0
Manufacturing Damage	253.3	1,919.6	2,172.9
Safety Problem	67.5	985.4	1,052.9
Total	374.8	3,721.0	4,095.8
	Short Lead (60 Minutes)	Long Lead (120 Minutes)	
Reason	Locations	Locations	Total
Generation Start Time	67	452	519
Manufacturing Damage	207	797	1,004
Safety Problem	79	1,590	1,669
Total	353	2,839	3,192

There are two ways to measure load reductions of demand resources. The Firm Service Level (FSL) method, applied to the summer, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF).[27] 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.[28] 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.[29] 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.[30]

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

25 OATT Attachment DD-1, Section A.2(a).
26 Data for generation start time and mass market communication categories were combined based on confidentiality rules.
27 Real-time load is hourly metered load.
28 135 FERC ¶ 61,212 (2011).
29 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 55 (Feb. 9, 2023).
30 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 55 (Feb. 9, 2023).

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.[31] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[32] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. If an end customer has 3 MW of load during the coincidental peak load hour, but only 1 MW during the coincidental winter peak load hour, the end use customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.[33] 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:

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

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

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

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

Table 6-8 shows the MW registered by measurement and verification method and by technology type for the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-8 Nominated MW by each demand response method: 2022/2023 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,251.2	2,152.0	189.7	757.3	4,238.4	22.8	48.4	8,659.9	99.98%
Guaranteed Load Drop	0.3	1.5	0.0	0.0	0.1	0.0	0.0	1.8	0.02%
Total	1,251.4	2,153.5	189.7	757.3	4,238.5	22.8	48.4	8,661.8	100.0%
Percent by method	14.4%	24.9%	2.2%	8.7%	48.9%	0.3%	0.6%	100.0%	

31 OATT Attachment DD.5.11.
32 OATT Attachment M-2.
33 162 FERC ¶ 61,159 (2018).

Table 6-9 shows the fuel type used in the onsite generators for the 2022/2023 Delivery Year in the emergency and pre-emergency programs. For the 2022/2023 Delivery Year, 1,251.4 MW of the 8,661.8 nominated MW, 14.4 percent, used onsite generation. Of the 1,251.4 MW, 83.4 percent used diesel and 16.6 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-9 Onsite generation fuel type (MW): 2022/2023 Delivery Year

	2022/2023	
Fuel Type	MW	Percent
Diesel	1,043.2	83.4%
Natural Gas, Gasoline, Oil, Propane, Waste Products	208.3	16.6%
Total	1,251.4	100.0%

Table 6-10 shows the MW registered by measurement and verification method and by technology type for the 2021/2022 Delivery Year. For the 2021/2022 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-10 Nominated MW by each demand response method: 2021/2022 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,232.2	1,911.6	191.1	666.3	3,903.7	17.2	39.9	7,962.0	99.98%
Guaranteed Load Drop	0.3	1.0	0.0	0.0	0.0	0.0	0.3	1.5	0.02%
Total	1,232.5	1,912.6	191.1	666.3	3,903.7	17.2	40.1	7,963.5	100.0%
Percent by method	15.5%	24.0%	2.4%	8.4%	49.0%	0.2%	0.5%	100.0%	

Table 6-11 shows the fuel type used in the onsite generators for the 2021/2022 Delivery Year in the emergency and pre-emergency programs. For the 2021/2022 Delivery Year, 1,232.5 MW of the 7,963.5 nominated MW, 15.5 percent, use onsite generation. Of the 1,232.5 MW, 83.5 percent use diesel and 16.5 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-11 Onsite generation fuel type (MW): 2021/2022 Delivery Year

	2021/2022	
Fuel Type	MW	Percent
Diesel	1,029.2	83.5%
Natural Gas, Gasoline, Oil, Propane, Waste Products	203.2	16.5%
Total	1,232.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.[34] With the full implementation of the Capacity Performance rules in the 2020/2021 Delivery Year, the requirement that subzones be defined one day prior to dispatch is no longer in effect. A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, as defined by the zip code of the enrolled end use customer's address, the entire registration must respond. Subzonal dispatch creates a PAI for the subzone, even if PJM does not measure compliance for demand resources. There are currently seven defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN and AEP_MARION.[35] 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.

34 OATT Attachment DD, Section 11.
35 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).

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.[36] 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.[37] 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.[38]

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 five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[39]

Under the capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment intervals (PAI).[40] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. PJM cannot dispatch pre-emergency or emergency demand response without triggering a PAI and measuring compliance. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now effectively classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. Table 6-12 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2021/2022 and 2022/2023 Delivery Years. There are 8,129.7 nominated MW of demand response for the 2022/2023 Delivery Year, 45.2 percent of the required reserve margin and 33.1 percent of the actual reserve margin for the 2022/2023 Delivery Year.[41]

36 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>.

37 See the *2018 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

38 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 55 (Feb. 9, 2023).

39 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 55 (Feb. 9, 2023).

40 OATT § 1 (Performance Assessment Hour).

41 *2022 Annual State of the Market Report for PJM*, Section 5: Capacity Market, Table 5-7.

Table 6-12 Demand response nominated MW compared to reserve margin: 2021/2022 and 2022/2023 Delivery Years[42]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2021/2022	10,512.1	20,176.5	52.1%	28,005.0	37.5%
2022/2023	8,129.7	17,990.4	45.2%	24,586.6	33.1%

PJM will dispatch demand resources by zone or subzone for demand resources, or within a PAI area for Capacity Performance resources. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency Action Area (EAA).[43] [44] 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.

42 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.

43 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.

44 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 55 (Feb. 9, 2023).

Definition of Compliance

PJM's reporting of load management events overstates 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. 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.

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.[45] 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.[46]

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

45 157 FERC ¶ 61,067 (2016).

46 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 123 (Feb. 9, 2023).

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."[47] 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.[48] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance.[49]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment, but the testing requirements are inadequate.[50] The CSP must notify PJM of the intent to test 48 hours in advance of the test. A notification of intent to test must be submitted in the DR Hub system. If a CSP failed to provide the required load reduction in a zone by less than 25 percent of their Summer Average RPM Commitment in the zone, the CSP may conduct a retest of the subset of registrations in the zone that failed. If the CSP elects to not retest a subset of registrations that failed the test, such registrations will maintain the compliance result achieved in the initial test. Retesting must be performed at the same time of day and under approximately the same weather conditions. Multiple tests may be conducted; however, only one test result may be submitted for each end use customer site in the DR Hub System for

47 OA Schedule 1 § 8.2.

48 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>.

49 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.

50 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. 55 (Feb. 9, 2023).

compliance evaluation. Test data must 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 does not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. Given that demand resources are now an annual product, multiple tests are required to ensure reduction capability year round. The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event.

Table 6-13 shows the test penalties by delivery year by product type for the 2016/2017 Delivery Year through the 2021/2022 Delivery Year.[51] 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 0.36 percent of total DR revenues in the 2021/2022 Delivery Year.

Table 6-13 Test penalties by delivery year by product type: 2016/2017 through 2021/2022

	2016/2017			2017/2018			2018/2019			2019/2020			2020/2021			2021/2022		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665	0.03	$179.80	$2,100									
Extended Summer	7.3	$138.14	$370,290	10.5	$142.86	$547,928												
Annual	4.8	$137.45	$241,406	16.3	$144.00	$855,940												
Base DR and EE							16.3	$186.80	$1,110,134	30.2	$154.69	$1,712,177						
Capacity Performance	2.1	$160.80	$124,310	0.6	$181.80	$40,146	2.6	$188.55	$178,795				0.9	$125.30	$39,422	23.1	$176.79	$1,487,430
Total	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678	18.9	$187.03	$1,291,030	30.2	$154.69	$1,712,177	0.9	$125.30	$39,422	23.1	$176.79	$1,487,430

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[52] There are 98.1 percent of nominated MW for the 2022/2023 Delivery Year registered under the full program option. There are 1.9 percent of nominated MW for the 2022/2023 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit

51 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.

52 *Id.*

incremental energy offers in energy markets."[53] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[54] [55] 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.[56] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[57]

Table 6-14 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2021/2022 Delivery Year. The majority of participants, 77.3 percent of locations and 52.1 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2021/2022 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.3 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $166.11 per location and $150.48 per nominated MW.

Table 6-14 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2021/2022 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	107	0.7%	207.8	2.7%	$97.45	$50.19
$1,000-$1,275	2,912	19.5%	3,214.4	41.4%	$166.11	$150.48
$1,275-$1,550	367	2.5%	295.3	3.8%	$44.06	$54.75
$1,550-$1,849	11,511	77.3%	4,046.8	52.1%	$50.83	$144.59
Total	14,897	100.0%	7,764.4	100.0%	$73.53	$141.09

53 161 FERC ¶ 61,153 at P 8 (2017).
54 139 FERC ¶ 61,057 (2012).
55 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.
56 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
57 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 42 (Oct. 28, 2022).

Table 6-15 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2022/2023 Delivery Year. The majority of participants, 80.3 percent of locations and 51.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.8 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $163.04 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	2,854	16.9%	3,514.7	41.7%	$163.04	$132.39
$1,275-$1,550	352	2.1%	370.9	4.4%	$42.65	$40.48
$1,550-$1,849	13,523	80.3%	4,353.4	51.7%	$41.89	$130.13
Total	16,848	100.0%	8,426.1	100.0%	$62.71	$125.38

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, and has cleared auctions for the 2021/2022 Delivery Year and 2022/2023 Delivery Year.[58] Table 6-16 shows the Nominated MW of Price Responsive Demand for the 2021/2022 and 2022/2023 Delivery Years.

Table 6-16 Nominated MW of price responsive demand: 2021/2022 and 2022/2023 Delivery Years

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2022/2023	230.0	230.0	40.0	190.0	19.6	110.0	80.0
2021/2022	510.0	510.0	75.0	435.0	35.7	195.0	240.0

58 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>.

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:[59]

*PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) plus,*

*(Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].*

Effective with the 2022/2023 Delivery Year, the factor equal to (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) is eliminated in the calculation of the PRD Credit.

Table 6-17 shows the PRD Credits for the 2020/2021 and 2021/2022 Delivery Years.

Table 6-17 PRD Credits for 2020/2021 and 2021/2022 Delivery Years

Delivery Year	PRD Credit
2021/2022	$38,282,769.14
2020/2021	$23,649,865.05

59 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 55 (Feb. 9, 2023).

A PRD Provider with a daily commitment compliance shortfall in a subzone/ zone for RPM or FRR is assessed a Daily PRD Commitment Compliance Penalty. The Daily PRD Commitment Compliance Penalty is determined as:

*PRD Commitment Compliance Penalty = MW shortfall in the Sub-zone/ Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate*

The revenue collected from assessment of the PRD Commitment Compliance Penalty is distributed to all entities that committed Capacity Resources in the RPM Auctions for the relevant delivery 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.

Table 6-18 shows the PRD Commitment Compliance Penalties for the 2020/2021 and 2021/2022 Delivery Years

Table 6-18 PRD Commitment Compliance Penalties for 2020/2021 and 2021/2022 Delivery Years

Delivery Year	Charges
2021/2022	$395,319.95
2020/2021	$0

PRD committed in RPM for the current delivery year bids in the PJM Energy Market. PRD Curves may be submitted by PRD Providers in the PJM Energy Market by 1100 at the closing of the day-ahead bid period. PRD Curves submitted by PRD Providers are identified in the day-ahead market software and user interface. PRD bids are modeled in the real-time energy market only, and are modeled in the real-time dispatch algorithms. PRD curves are not modeled in the day-ahead market clearing process. PRD Curves in the energy market are modeled in the real-time dispatch algorithms and can set Real-time LMP. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to real-time LMPs for the PRD Curves that are submitted. The maximum bid price of the PRD Curve is the applicable energy market offer cap. When PRD sellers offer at the cap, they limit the number of times that PRD is called on to respond.

The PRD rules fall short of defining an effective and efficient product that is aligned with the definition of a capacity resource.[60] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[61] 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.[62]

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.

60 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
61 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).
62 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

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 February 28, 2023. The ownership of economic demand response resources was highly concentrated in the first two months of 2022 and the first two months of 2023.[63] 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 the first two months of 2023. The HHI for economic demand response in the first two months of 2023 increased by 1528, 20.4 percent, from 7861 in the first two months of 2022 to 9459 in the first two months of 2023.

Table 6-19 Average hourly MWh HHI and market concentration in the economic program: January 2022 through February 2023[64]

	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	7182	9953	38.6%	99.8%			99.8%		
Feb	7474	8965	20.0%	98.8%			99.0%		
Mar	8927			97.6%			97.8%		
Apr	7310			89.8%			88.3%		
May	7003			96.5%			96.8%		
Jun	7147			93.5%			93.1%		
Jul	7500			94.9%			94.1%		
Aug	6716			92.6%			87.2%		
Sep	8042			99.5%			99.8%		
Oct	9400			100.0%			100.0%		
Nov	8121			99.8%			99.8%		
Dec	7745			99.7%			99.8%		
Total	7826	9622	23.0%	94.8%	100.0%	5.2%	93.0%	100.0%	7.0%

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 $11.88 per MWh, 19.6 percent, from $60.62 per MWh in the first three months of 2022 to $48.74 per MWh in the first three months of 2023. The PJM real-time load-weighted average LMP in the first three months of 2023 was $30.28 per MWh, a decrease of $23.85 per MWh, 44.1 percent, compared to the average LMP in the first three months of 2022. Curtailed energy for the economic program was 6,411 MWh in the first three months of 2023, a decrease of 217.5 MWh, 3.3 percent, as compared to curtailed energy for the economic program in the first three months of 2022. Total credits paid for the economic load response program in the first three months of 2023 were $312,479, a decrease of $89,367, 22.2 percent, compared to the total credits paid for the economic load response program in the first three months of 2022.

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

(Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	58,195	$12,727,388	$218.70
2015	38,644	$4,175,116	$108.04
2016	16,038	$672,506	$41.93
2017	12,973	$534,378	$41.19
2018	14,623	$951,955	$65.10
2019	7,260	$390,708	$53.82
2020	1,216	$34,124	$28.06
2021	3,912	$228,087	$58.31
2022	6,629	$401,846	$60.62
2023	6,411	$312,479	$48.74

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.[65] For example, assume a demand resource has an economic

63 All HHI calculations in this section are at the parent company level.
64 January and February 2023 reduction and credit share values are not reported based on confidentiality rules.
65 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 123 (Feb. 9, 2023).

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.[66] 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 February 28, 2023.

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

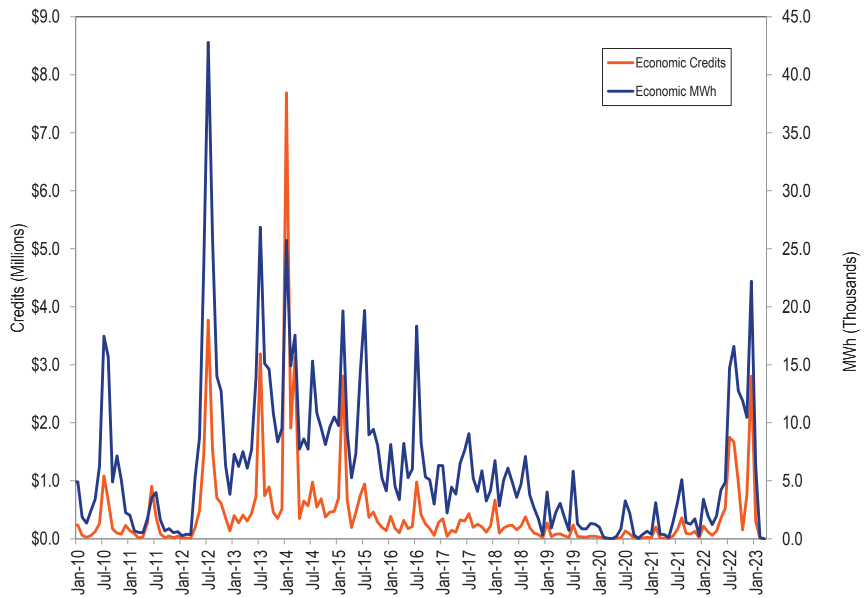


Table 6-21 shows performance for the first three months of 2022 and 2023 in the economic program by control zone. Total reported reductions under the economic program decreased by 218 MWh, 3.3 percent, from 6,629 MWh in the first three months of 2022 to 6,411 MWh in the first three months of 2023. Total revenue under the economic program decreased by $0.1 million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[67]

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

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

67 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.

68 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 90 (Jan. 25, 2023).

Table 6-21 Economic program participation by zone: January through March, 2022 and 2023

		Credits			MWh Reductions			Credits per MWh Reduction		
Zones	Zones	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
AECO	ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	AEP	$125,975.71	$843.64	(99.3%)	1,822	19	(98.9%)	$69.12	$44.02	(36.3%)
APS	APS	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
ATSI	ATSI	$88,577.18	$0.00	NA	1,745	0	NA	$50.77	NA	NA
BGE	BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
COMED	COMED	$19,993.17	$986.56	(95.1%)	494	49	(90.0%)	$40.46	$19.96	(50.7%)
DAY	DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUKE	DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	DUQ	$382.79	$303,987.80	79,313.7%	8	6,268	77,506.0%	$47.40	$48.50	2.3%
DOM	DOM	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DPL	DPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPL	JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
METED	MEC	$19,750.70	$3,600.72	(81.8%)	327	44	(86.6%)	$60.38	$82.02	35.8%
OVEC	OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	PECO	$91,107.40	$1,425.31	(98.4%)	1,321	19	(98.6%)	$68.96	$75.84	10.0%
PENELEC	PE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PEPCO	PEPCO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PPL	PPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PSEG	PSEG	$56,059.19	$1,634.76	(97.1%)	911	13	(98.6%)	$61.53	$129.88	111.1%
REC	REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	Total	$401,846.14	$312,478.79	(22.2%)	6,629	6,411	(3.3%)	$60.62	$48.74	(19.6%)

Table 6-22 shows average reported MWh reductions and credits by hour for the first three months of 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 the first three months of 2022, 69.1 percent of the reported reductions and 68.7 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in the first three months of 2023, 66.3 percent of the reported reductions and 65.8 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response decreased by $16.53 per MWh, 22 percent, from $70.24 per MWh in the first three months of 2022 to $53.71 per MWh during 2022.

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

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
1 through 6	547	424	(22%)	$31,258	$20,160	(36%)	$67.87	$46.40	(32%)
7	378	580	54%	$23,031	$28,552	24%	$84.39	$51.57	(39%)
8	483	803	66%	$30,655	$43,726	43%	$89.85	$57.05	(37%)
9	494	566	14%	$30,267	$28,678	(5%)	$71.55	$49.16	(31%)
10	419	397	(5%)	$24,154	$18,259	(24%)	$64.25	$45.52	(29%)
11	414	311	(25%)	$26,468	$14,839	(44%)	$69.57	$47.43	(32%)
12	334	224	(33%)	$18,980	$10,013	(47%)	$63.60	$44.48	(30%)
13	285	49	(83%)	$15,021	$2,099	(86%)	$62.43	$42.78	(31%)
14	270	5	(98%)	$15,488	$381	(98%)	$58.96	$72.78	23%
15	225	5	(98%)	$12,614	$565	(96%)	$56.41	$69.07	22%
16	204	5	(98%)	$11,107	$394	(96%)	$58.78	$69.26	18%
17	266	177	(33%)	$14,460	$7,788	(46%)	$67.31	$44.66	(34%)
18	439	783	78%	$26,298	$40,848	55%	$84.18	$53.56	(36%)
19	464	718	55%	$31,117	$35,216	13%	$77.56	$47.78	(38%)
20	433	571	32%	$28,506	$26,817	(6%)	$73.95	$47.15	(36%)
21	334	440	32%	$21,436	$19,866	(7%)	$72.33	$45.50	(37%)
22	283	178	(37%)	$18,007	$8,230	(54%)	$71.55	$46.08	(36%)
23 through 24	357	175	(51%)	$22,979	$6,048	(74%)	$69.81	$86.61	24%
Total	6,629	6,411	(3%)	$401,846	$312,479	(22%)	$70.24	$53.71	(22%)

Table 6-23 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in the first three months of 2023 and 2022. In the first three months of 2023, 0.7 percent of reported MWh reductions and 1.4 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-23 Frequency distribution of economic program zonal load-weighted average LMP (By hours): January through March, 2022 and 2023

	MWh Reductions			Program Credits		
LMP	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
$0 to $25	29	12	(58%)	$1,323	$221	(83%)
$25 to $50	2,378	4,223	78%	$118,979	$197,065	66%
$50 to $75	2,594	1,769	(32%)	$182,595	$90,041	(51%)
$75 to $100	788	273	(65%)	$57,256	$15,355	(73%)
$100 to $125	276	45	(84%)	$16,287	$2,331	(86%)
$125 to $150	119	45	(62%)	$6,966	$2,983	(57%)
$150 to $175	109	0	(100%)	$5,273	$0	(100%)
> $175	336	44	(87%)	$13,169	$4,483	(66%)
Total	6,629	6,411	(3%)	$401,846	$312,479	(22%)

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 the first two months of 2023, real-time scheduled exports have paid the highest Economic Load Response charges.

Table 6-24 Zonal Economic Load Response charge: January through February, 2023[69]

Zone	January	February	Total
AECO	$1,954	$100	$2,054
AEP	$34,662	$863	$35,526
APS	$18,119	$551	$18,670
ATSI	$15,268	$396	$15,663
BGE	$16,116	$413	$16,530
COMED	$13,709	$152	$13,860
DAY	$5,342	$138	$5,480
DUKE	$6,847	$141	$6,988
DUQ	$3,157	$115	$3,271
DOM	$41,259	$1,336	$42,595
DPL	$4,429	$246	$4,676
EKPC	$4,062	$88	$4,150
JCPLC	$3,814	$246	$4,061
MEC	$6,248	$203	$6,450
OVEC	$36	$1	$37
PECO	$6,195	$471	$6,666
PE	$4,356	$151	$4,507
PEPCO	$11,201	$300	$11,501
PPL	$8,671	$437	$9,108
PSEG	$7,069	$473	$7,542
REC	$236	$18	$254
Exports	$92,222	$668	$92,890
Total	$304,972	$7,506	$312,479

69 Load response charges were downloaded as of April 6, 2023 and may change as a result of continued PJM billing updates.

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

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

Zone	January	February	Zonal Average
ACEC	$0.003	$0.000	$0.001
AEP	$0.003	$0.000	$0.002
APS	$0.004	$0.000	$0.002
ATSI	$0.003	$0.000	$0.001
BGE	$0.006	$0.000	$0.003
COMED	$0.002	$0.000	$0.001
DAY	$0.004	$0.000	$0.002
DUKE	$0.003	$0.000	$0.002
DUQ	$0.003	$0.000	$0.001
DOM	$0.004	$0.000	$0.002
DPL	$0.003	$0.000	$0.002
EKPC	$0.003	$0.000	$0.002
JCPLC	$0.002	$0.000	$0.001
MEC	$0.000	$0.000	$0.000
OVEC	$0.003	$0.000	$0.002
PECO	$0.002	$0.000	$0.001
PE	$0.003	$0.000	$0.002
PEPCO	$0.005	$0.000	$0.002
PPL	$0.002	$0.000	$0.001
PSEG	$0.002	$0.000	$0.001
REC	$0.002	$0.000	$0.001
Exports	$0.021	$0.000	$0.011
Monthly Average	$0.004	$0.000	$0.002

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 increased by $44.1 thousand, 16.5 percent, from $267.3 thousand in the first two months of 2022 to $311.5 thousand in the first two months of 2023. The real-time Economic Load Response charges decreased $74.6 thousand, 98.7 percent, from $75.6 thousand in the first two months of 2022 to $1.0 thousand in the first two months of 2023.[70]

70 Load response charges were downloaded as of April 6, 2023, 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.

Table 6-26 Monthly day-ahead and real-time economic load response charge: January 2022 through February 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	$304,465	46.4%	$11,554	$507	(95.6%)
Feb	$59,319	$7,012	(88.2%)	$64,082	$495	(99.2%)
Mar	$17,440			$41,425		
Apr	$100,975			$30,536		
May	$264,451			$92,237		
Jun	$247,738			$278,463		
Jul	$1,574,857			$174,780		
Aug	$1,520,387			$151,364		
Sep	$772,279			$204,355		
Oct	$150,988			$4,205		
Nov	$757,878			$2,763		
Dec	$2,797,626			$9,227		
Total	$8,471,966	$311,477	(96.3%)	$1,064,991	$1,002	(99.9%)

Table 6-27 shows registered sites and MW for the last day of each month for the period January 1, 2019, through March 31, 2023. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations increased by 38, 11.7 percent, from 325 in the first three months of 2022 to 363 in the first three months of 2023. Average monthly registered MW increased by 452 MW, 19.8 percent, from 2,289 MW in the first three months of 2022 to 2,741 MW in the first three months of 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 106 economic registrations and 106 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,442.2 nominated economic MW and 1,160.7 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 March 2023[71]

	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	353	2,722
Feb	370	2,640	382	2,912	275	1,503	323	2,256	362	2,710
Mar	378	2,648	380	2,941	284	1,514	330	2,377	375	2,790
Apr	366	2,594	350	2,917	293	1,538	330	2,382		
May	372	3,193	308	2,824	319	1,658	326	2,377		
Jun	370	2,768	285	1,418	313	2,136	315	2,323		
Jul	376	2,899	283	1,453	312	2,105	310	2,412		
Aug	360	2,885	292	1,482	322	2,122	318	2,451		
Sep	368	2,954	297	1,566	322	2,256	329	2,565		
Oct	375	2,909	275	1,361	332	2,267	333	2,575		
Nov	379	3,051	280	1,375	333	2,270	338	2,593		
Dec	383	3,070	282	1,327	320	2,256	359	2,640		
Avg	373	2,855	316	2,040	309	1,927	328	2,432	363	2,741

71 Data for years 2010 through 2017 are available in the *2017 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 February 28, 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 in January and decreased in February of 2023 compared to the same months in 2022.[72]

Table 6-28 Sum of maximum MW reported reductions for all registrations per month: 2011 through February 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	16
Mar	81	72	127	369	198	120	111	71	38	12	20	30	
Apr	80	108	133	146	143	118	54	71	41	3	22	43	
May	98	143	192	151	161	131	169	70	22	12	9	53	
Jun	561	954	433	483	833	121	240	105	26	38	125	110	
Jul	561	1,631	1,088	665	1,362	1,316	936	518	770	135	134	151	
Aug	161	952	497	358	272	249	141	581	33	99	827	163	
Sep	84	451	530	795	816	263	140	112	76	31	35	88	
Oct	81	242	168	214	136	150	88	69	29	9	31	67	
Nov	86	165	155	166	127	116	81	54	35	12	31	58	
Dec	88	98	168	155	122	147	83	11	31	14	19	116	
Annual	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196	921	264	63

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: January through March, 2011 through 2023

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Number of Settlements	91	21	368	1,314	602	267	347	361	172	83	123	369	100

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 decreased by 5, 33.3 percent, from 15 in the first three months of 2022 to 10 in the first three months of 2023. All participants must be registered through a CSP.

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

(Jan-Mar)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Active CSPs	5	4	9	12	11	6	6	11	9	7	8	5	5
Active Participants	25	9	49	115	47	17	19	26	18	9	18	15	10

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[73] 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."[74] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price

72 Maximum MW reductions were downloaded on April 6, 2023, and may change as a result of continued PJM billing updates.

73 157 FERC ¶ 61,115 at P 139 (2016).

74 *Id.* at 8.

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.[75] 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.[76]

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 March 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 the first three months of 2023, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in a single month, January.

75 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 123 (Feb. 9, 2023).

76 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 123 (Feb. 9, 2023).

Table 6-31 Net benefits test threshold prices: August 2010 through March 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	
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01	$14.69	$21.40	$42.94	
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35	$44.29	
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59	$48.67	
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52	$44.08	
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06	$55.39	
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	$55.97	
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	
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	
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	$31.26

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.[77] In the first three months of 2023, the highest zonal LMP in PJM was higher than the NBT threshold price 1,526 hours out of 2,159 hours, or 70.7 percent of all hours. Reductions occurred in 250 hours, 16.4 percent, of those 1,526 hours in the first two months of 2023. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2022, through February 28, 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 the first two months of 2023.

Table 6-32 Hours with price higher than NBT and economic load response occurrences in those hours: 2021 through March 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%)	70.3%	36.9%	(33.4%)
Feb	672	672	663	412	(37.9%)	47.8%	19.7%	(28.2%)
Mar	743	743	742	656	(11.6%)	55.3%		
Apr	720		720			66.4%		
May	744		744			82.9%		
Jun	720		684			71.1%		
Jul	744		680			71.3%		
Aug	744		744			68.5%		
Sep	720		623			68.7%		
Oct	744		529			57.5%		
Nov	721		569			48.9%		
Dec	744		702			69.8%		
Total	8,760	2,159	8,124	1,526	(81.2%)	65.4%	16.4%	(49.0%)

77 The MWh for demand resources were downloaded as of April 6, 2023, and may change as a result of continued PJM billing updates.

Energy Efficiency

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not produce power, but are intended to reduce power consumption. The Nominated MW for EE resources are not measured, although they could be, but a calculated value based on a set of largely unverified and unverifiable assumptions. An installed EE resource may participate as a capacity resource for up to four consecutive delivery years.[78]

Prescriptive energy efficiency MW have an assumed savings calculated based on an assumed installation rate and the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM Capacity Market is prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement 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. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.[79] There is no evidence that the programs result in changed behavior or increases in savings.

The MMU recommends that Energy Efficiency Resources (EE) not continue to be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[80] EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets because to the extent that it 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.

The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. The purpose of the registration system is to prevent duplicative claims to capacity rights and to document installation periods of energy efficiency to verify eligibility for continued participation measures. Energy Efficiency projects should be clearly identified by retail customer account, year of project installation and a description of the Energy Efficiency project. Energy Efficiency Resources are eligible to participate as supply in RPM for up to four years following their installation. Beyond the fourth year, the energy savings benefit of an Energy Efficiency project is incorporated into the load forecast used for RPM Auctions.

A registration system would also serve the benefit of preventing multiple Energy Efficiency Providers from claiming capacity rights to the same project. The Energy Efficiency Resource Provider offering an Energy Efficiency Resource as a Capacity Resource into RPM must demonstrate to PJM that it has the legal authority to claim the demand associated with such Energy Efficiency Resource.[81] The Energy Efficiency Resource Provider can satisfy this requirement by submitting to PJM a written sworn, notarized statement of one of its corporate officers certifying that the Energy Efficiency Resource Provider has the legal authority to claim the demand reduction associated with the EE installations that constitute the Energy Efficiency Resource for the applicable delivery year. The Energy Efficiency Resource Provider can also satisfy this requirement by including a statement in their Energy Efficiency Post-Installation Measurement & Verification Report that they have legal authority to claim the demand reduction associated with the EE installations that constitute the Energy Efficiency Resource for the applicable delivery

78 PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 55 (Feb. 9, 2023).
79 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 05 (Sep. 21, 2022).
80 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).
81 EE Post-Installation Measurement & Verification Report Template, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/ee-post-installation-mv-report-template.ashx> *(Accessed Aug. 5, 2022).*

year. 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 Energy Efficiency installations as well as evidentiary requirements such as signed contracts with their customers conferring such rights. Energy efficiency resources are included in the PJM Capacity Market.

Table 6-33 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2011/2012 through 2022/2023 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[82] Only Kentucky has been authorized by the Commission.[83] The total MW of energy efficiency resources committed increased by 19.3 percent from 4,806.2 MW in the 2021/2022 Delivery Year to 5,734.8 MW in the 2022/2023 Delivery Year.[84]

Table 6-33 Energy efficiency resources (MW): 2011/2012 through 2022/2023 Delivery Years

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE Percent Cleared
2011/2012	76.4	134,139.6	0.1%
2012/2013	666.1	141,061.8	0.5%
2013/2014	904.2	159,830.5	0.6%
2014/2015	1,077.7	161,092.4	0.7%
2015/2016	1,189.6	173,487.4	0.7%
2016/2017	1,723.2	179,749.0	1.0%
2017/2018	1,922.3	180,590.3	1.1%
2018/2019	2,296.3	175,957.4	1.3%
2019/2020	2,528.5	177,040.6	1.4%
2020/2021	3,569.5	173,688.5	2.1%
2021/2022	4,806.2	174,713.0	2.8%
2022/2023	5,734.8	150,465.2	3.8%

82 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).
83 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).
84 See the *2021 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

Distributed Energy Resources

Distributed Energy Resources (DER) generally include small scale generation directly connected to the grid, generation connected to distribution level facilities, behind the meter generation and some energy storage facilities. FERC issued Order No. 2222 on September 17, 2020, with the goal of removing barriers for small distributed resources to enter the wholesale market by allowing them to aggregate in order to encourage competition.[85]

PJM made a compliance filing at FERC on February 1, 2022, and the MMU provided comments.[86] [87] FERC issued an order on March 1, 2023.[88] PJM submitted an informational filing and a 30-day compliance filing on March 31, 2023.[89]

In the March 1st Order, FERC directed PJM to file, within 30 days of the date of the issuance of the order, a further compliance filing to remove its proposal to exempt DER Capacity Aggregation Resources that include component DERs that are co-located with retail end-use load from the capacity market power mitigation rules.[90] FERC rejected the proposed rule because it requires reforms to existing capacity market power mitigation rules, which are outside the scope of the proceeding. The other directives, which are required to be filed by September 1, 2023,[91] include 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 pre-registration process and specifying utility review criteria.

PJM's March 31st Filing was not responsive to FERC's directive. PJM proposed to exempt a DER Capacity Aggregation Resource or a part of a DER Capacity

85 172 FERC ¶ 61,247 at PP 6–7 (2020).
86 Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022).
87 Comments of the Independent Market Monitor for PJM, Docket No. ER22-962 (April 1, 2022); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER22-962 (April 18, 2022); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER22-962 (May 19, 2022); Comments of the Independent Market Monitor for PJM, Docket No. ER22-962 (July 28, 2022).
88 182 FERC ¶ 61,143 (2023).
89 PJM Interconnection, L.L.C., Order No. 2222 Informational Update Regarding Effective Date Implementation, Docket No. ER22-962-001 (March 31, 2023); PJM Interconnection, L.L.C., Order No. 2222 30-Day Compliance Filing Docket No. ER22-962-002 (March 31, 2023).
90 Individual DERs in DER Aggregation Resources. See definitions in the February 1st Filing.
91 Notice of Extension of Time, Docket No. ER22-962-001 (April 11, 2023).

Aggregation Resource that consists solely of Component DER co-located with retail end-use load, from the capacity market power mitigation rules (MSOC and MOPR).

Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets.

The EDCs' dual role as the distribution system operator and as a DER aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is structurally not competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. The March 1st Order refused to prevent EDCs from serving as DER aggregators because Order 2222 requires RTOs/ISOs not limit the business models under which DER aggregators can operate. The March 1st Order, however, stated a possibility of revisiting the issue if FERC discovers "evidence of undue discrimination regarding the participation of DER aggregations in RTO/ISO markets."[92] The exercise of market power should be prevented, not fixed after the fact. The MMU continues to recommend that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

The PJM market is a nodal market because nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed. 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 have impact on a constraint (or multiple constraints) at another time. Aggregation behind a single node is feasible, will not threaten the nodal market principle, and will encourage competition. The MMU recommends that PJM use a nodal approach for DER participation in PJM markets.

Under the proposed DER rules, favorable treatment of resources that participate in the DER aggregation model over other resources includes: exemption from the PJM interconnection process; no must offer requirement in the capacity market; exemption from the RPM Minimum Offer Price Rule ("MOPR") when co-located with retail load; exemption from the market seller offer cap ("MSOC") when co-located with retail load; and ability to reduce load and inject power into the grid at the same time. These exemptions from basic market rules are not appropriate even for small participants and are not necessary to facilitate participation. But large DERs that are already capable of participating in the PJM markets under the current rules should not be given the option to exploit the new rules. The March 1st Order accepted PJM's proposed maximum size requirement of 5 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 the 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. 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 March 31st Filing exempts component DERs co-located with retail load from the capacity MSOC and the MOPR. 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.

92 The March 1st Order at P334.

Demand response resources are not the same as DER aggregation resources. Demand response resources cannot inject energy into the grid while DER aggregation resources can; demand response resources are modeled as load reduction while DER aggregation resources should be modeled as generation. The rules for demand response resources and the rules for DER aggregation resources should not be the same because the two resource types function very differently in the PJM market.

No resource should be paid more than once for its services. In most of the states in PJM, net energy metering means paying for resources on the distribution system at the full retail rate. As a result of the fact that retail rates include all 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.

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.[93] 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.[94] Any resource selling a PSA must reduce load on any day in which its trigger is met or exceeded. The trigger is based on the actual maximum daily temperature humidity index (THI) for the relevant PJM zone. When the trigger is met, the PSA must comply with its defined offer parameters including number of hours of interruption. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment value in future delivery years. Performance is measured based on the aggregated Customer Baseline (CBL). PJM applies a three year rolling average of the annual peak shaving performance ratings to the program's total participating MW in order to determine its peak shaving adjustment.

Performance Assessment Events

There were two performance assessment events in the last 12 months in PJM. The first event was in the AEP Marion Subzone and involved only demand resources. The second was a result of Winter Storm Elliott.

Definition of Performance

The definition of performance does not require an actual load reduction in response to a notice from PJM. What is termed an actual load reduction is measured as the difference between the amount of capacity paid for (PLC) and the metered load. 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.

For a Firm Service Level customer on a registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval in the summer period (June through October and May of the Delivery Year) is calculated as the end-use customer's Peak Load Contribution minus the hourly metered load multiplied by the loss factor.

93 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

94 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 35 (December 31, 2021).

For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Interval is calculated as the end-use customer's Winter Peak Load multiplied by the Zonal Winter Weather Adjustment Factor multiplied by the loss factor, minus the hourly metered load multiplied by the loss factor.

Performance Shortfalls

Nonperformance during a PAI is measured by comparing a resource's actual performance to their expected performance. The expected performance of a DR resource is its CP commitment in ICAP terms. The actual performance of a DR resource is defined as the demand response provided plus the resource's real-time reserve or regulation assignment, if any. Ancillary services are determined as the real-time regulation or reserves on the resource. The demand response, or load reduction, provided is defined as the PLC minus the metered load.

The expected and actual performance for DR resources are calculated as:[95]

Expected Performance = CP Capacity Commitment (ICAP)

Actual Performance = Load Reduction + Regulation/Reserve Assignment

If a resource's actual performance is less than the expected performance, the resource is assessed a nonperformance penalty.

Emergency Energy Credits

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.[96] 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. 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. The energy provided by a demand resource eligible for emergency energy payments is equal to the CBL less the RT metered load.

95 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).
96 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.1, Rev. 123 (Feb. 9, 2023).

Settlements

Nonperformance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year.[97] Monthly charges and credits are billed by dividing the total dollar amount due or owed by the number of months remaining in the delivery year.

Metered demand response data are not telemetered to PJM but rely on EDC meter reading cycles. That is the primary reason that demand response data is provided with such a long lag. Demand response data are provided to PJM through the DR Hub System 45 days after the end of the month in which a Performance Assessment Interval occurred.

For example, load management compliance data for Elliott were provided to PJM by February 14, 2023. Load management emergency energy settlement data were provided to PJM by February 21, 2023, for the event on December 23, 2022. Load management emergency energy settlement data were provided to PJM by February 22, 2023, for the event on December 24, 2022.

PJM bills charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included the Performance Assessment Intervals. Non-Performance Charges are amortized over the number of months remaining in the delivery year. If there are less than six months remaining in the current delivery year, PJM may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current delivery year plus up to six monthly bills into the following delivery year (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills).

97 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55(Feb. 9, 2023).

For the June 2022 performance assessment event, charges and credits were first billed starting in the September 2022 monthly bill, issued in October, and continue through the May 2023 monthly bill.

For any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect to divide the total amount of Non-Performance Charges by either the number of remaining monthly bills in the current Delivery Year, or the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (nine bills). For an election under the second option, the monthly Non-Performance Charges are levelized, including interest for the six-month period following the current Delivery Year. The interest rate is electric interest rate established by the Federal Energy Regulatory Commission at the time of such election.[98]

Performance Assessment Event – AEP_Marion Subzone

On June 14, 15 and 16, 2022, PJM dispatched Pre-Emergency and Emergency DR resources in the Columbus, Ohio area of the AEP Zone defined as the AEP_MARION Load Management Subzone. These actions triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action Area for each applicable five minute interval (PAI).[99]

On June 14, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1550 EPT and ended on June 14, 2022 at 2200 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1620 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1650 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1750 EPT.

98 OATT, Attachment DD § 10A
99 OATT, Attachment DD § 10A

Table 6-34 Load management reduction action event times for June 14, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30 min)	1550	1620	2200
Emergency and Pre-Emergency	Short (60 min)	1550	1650	2200
Emergency and Pre-Emergency	Long (120 min)	1550	1750	2200

On June 15, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1050 EPT and ended on June 15, 2022 at 2200 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1120 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1150 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1250 EPT.

Table 6-35 Load management reduction action event times for June 15, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30 min)	1050	1120	2200
Emergency and Pre-Emergency	Short (60 min)	1050	1150	2200
Emergency and Pre-Emergency	Long (120 min)	1050	1250	2200

On June 16, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1230 EPT and ended on June 16, 2022 at 1700 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1300 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1330 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1430 EPT.

Table 6-36 Load management reduction action event times for June 16, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30 min)	1230	1300	1700
Emergency and Pre-Emergency	Short (60 min)	1230	1330	1700
Emergency and Pre-Emergency	Long (120 min)	1230	1430	1700

Performance

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).

The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response.

Immediately preceding the call for Load Management resources on June 14, 56 percent of registrations were already at load levels equal to or, below, their Peak Load Contribution. Immediately preceding the call for Load Management resources on June 15th, 62 percent of registrations were already at load levels equal to or, below, their Peak Load Contribution. Immediately preceding the call for Load Management resources on June 16th, 54 percent of registrations were already at load levels equal to or, below, their Peak Load Contribution.

Nonperformance Charges

Nonperformance charge rates applied during PAI are calculated on a modeled LDA basis for the relevant delivery year. The nonperformance charge rate for a specific resource is based on the Net CONE expressed in $/MW-day in ICAP for the LDA in which the resource is modeled and is calculated as:[100]

Nonperformance Charge Rate ($/MW-5-Minute Interval) = [(Net CONE x Number of Days in Delivery Year) / 30 Hours] / 12 Intervals

The applicable charge rate for the June 2022 PAI for those resources modeled in the AEP Zone (Rest of RTO LDA) for the 2022/2023 Delivery Year is shown in Table 6-37.[101]

100 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 55 (Feb. 9, 2023).
101 PJM, Planning Period Parameters for Base Residual Auction, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-planning-period-parameters-for-base-residual-auction.ashx> (Accessed Oct 6, 2022).

Table 6-37 Nonperformance Charge Rate

Zone	LDA	Net CONE (ICAP)	Charge Rate
AEP	RTO	$247.26	$250.69

This charge rate is multiplied by the performance shortfall in each PAI to determine the nonperformance financial penalty for committed CP resources. The nonperformance charge is calculated as:[102]

*Nonperformance Charge = Performance Shortfall MW * Nonperformance Charge Rate*

Table 6-38 Nonperformance Charges

Day	Avg Shortfall (MW/Interval)	Charges
June 14, 2022	5.9	$99,787.16
June 15, 2022	18.4	$590,567.72
June 16, 2022	35.1	$422,337.72
Total		$1,112,692.60

Figure 6-3 through Figure 6-5 show the aggregate nonperformance charge, expected reduction value and actual reduction value, by interval, of demand resources dispatched during the PAI events on June 14 through June 16, 2022.

102 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 55 (Feb. 9, 2023).

Figure 6-3 Nonperformance charges, expected and actual reduction values: June 14, 2022

Figure 6-4 Nonperformance charges, expected and actual reduction values: June 15, 2022

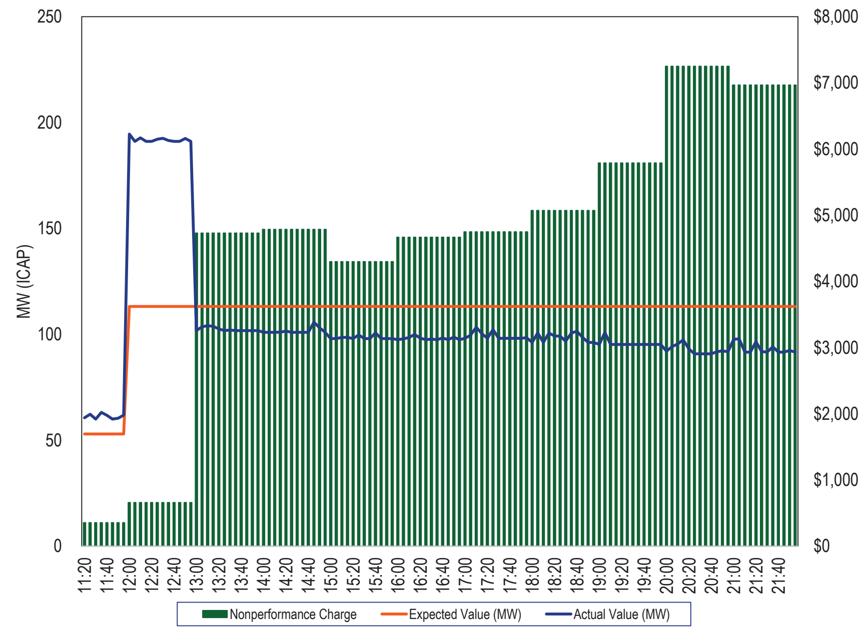
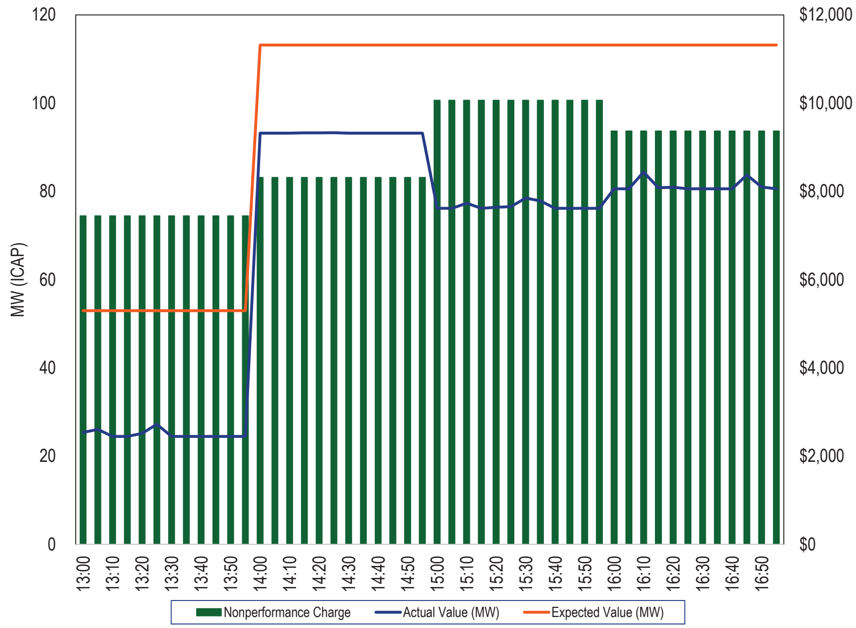


Figure 6-5 Nonperformance charges, expected and actual reduction values: June 16, 2022



Actual performance across all resources in the Emergency Action Area included the performance by resources that did not have a performance obligation, and over performance by some resources that did have a CP obligation. Demand Resources that are not capacity resources do not have an obligation to respond during an emergency and therefore do not contribute to the expected value. Table 6-39 shows the daily average actual performance as a percent of expected performance, with and without the contribution of resources that did not have an obligation to perform (non-CP resources).

The response overshot the expected response in the early part of each event and then leveled off or declined within each event. The performance declined significantly over the three day period.

Table 6-39 Daily average actual performance as a percent of expected performance: June 14, 15, and 16, 2022

Day	Including non-CP resources	Excluding non-CP resources
14-Jun-22	99.0%	96.3%
15-Jun-22	89.3%	86.8%
16-Jun-22	63.6%	62.3%

Bonus Performance

A resource with actual performance above its expected performance is assigned a share of the collected nonperformance charge revenues as a bonus performance credit. When calculating bonus megawatts, the actual performance of a dispatchable resource is capped at the megawatt level at which the resource was scheduled and dispatched by PJM during the performance assessment event.

The expected and actual performance calculations for bonus megawatt evaluations for load DR is:[103]

Expected Performance = CP Capacity Commitment (ICAP)

Actual Performance = Load Reduction + Reserve/Regulation Assignment

Table 6-40 Bonus performance credits: June 14, 15, and 16, 2022

Day	Avg Bonus (MW/Interval)	Credits
June 14, 2022	11.0	$99,787.16
June 15, 2022	13.3	$590,567.72
June 16, 2022	6.0	$422,337.72
Total		$1,112,692.60

Figure 6-6 through Figure 6-8 show the bonus MW and bonus credit, by interval, of demand resources dispatched during the PAI events on June 14 through June 16, 2022.

103 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).

Figure 6-6 Bonus performance by interval: June 14, 2022

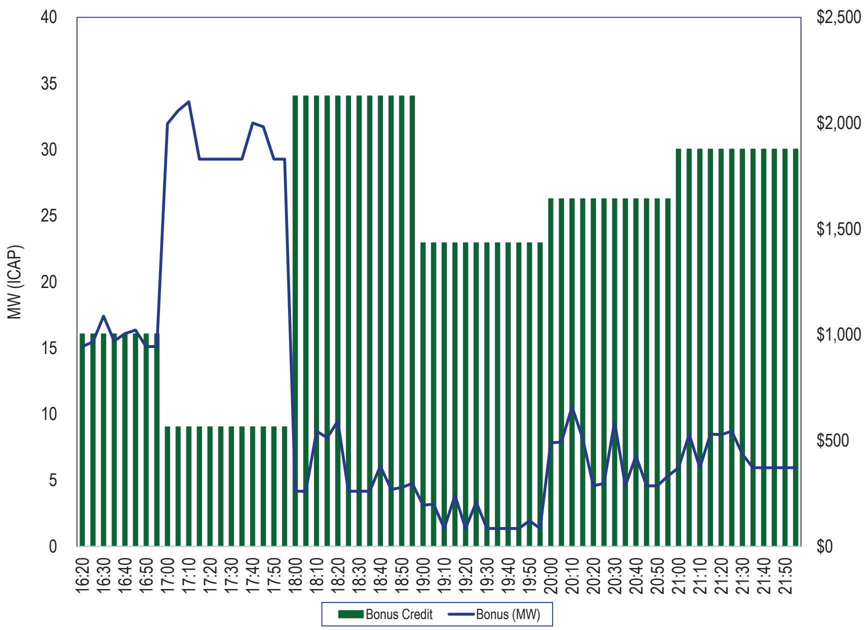


Figure 6-7 Bonus performance by interval: June 15, 2022

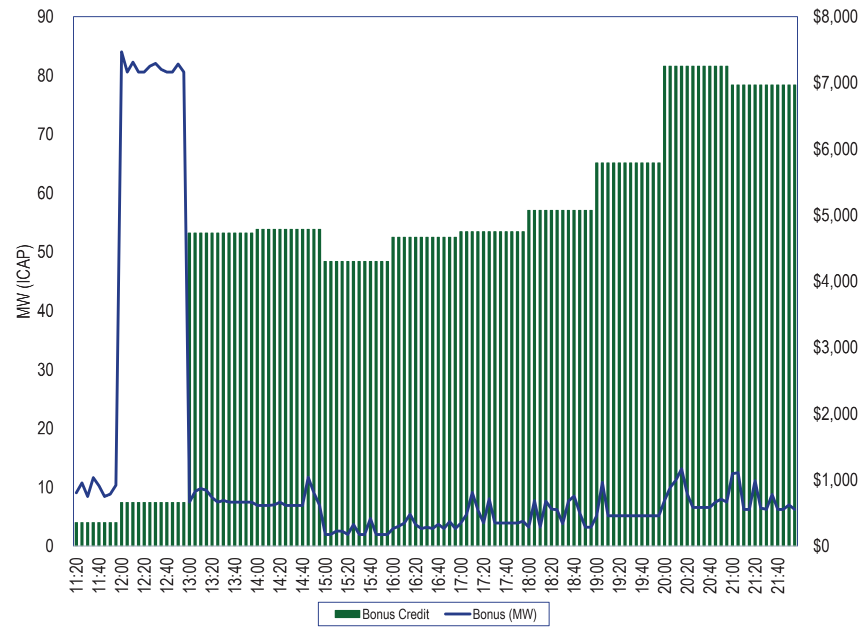
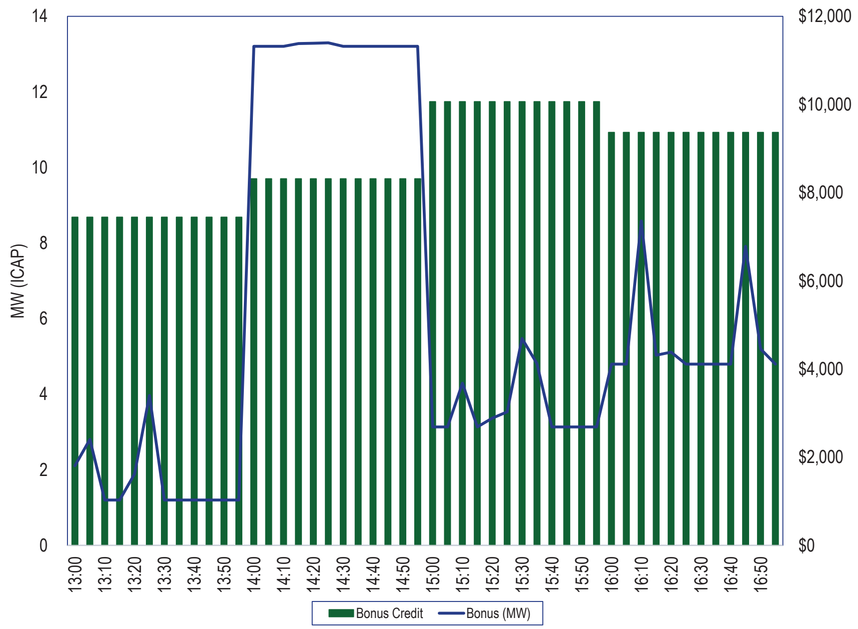


Figure 6-8 Bonus performance by interval: June 16, 2022



Emergency Energy Credits

Table 6-41 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices in the AEP Marion Load Management Subzone. The majority of participants, 79.2 percent of locations and 39.7 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. All registrations had a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $166.68 per location and $176.37 per nominated MW.

Table 6-41 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch price

Range of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost per Nominated MW (ICAP)
$1,000-$1,275	69	19.1%	65.2	53.9%	$166.68	$176.37
$1,275-$1,550	6	1.7%	7.7	6.3%	$0.00	$0.00
$1,550-$1,849	286	79.2%	48.0	39.7%	$2.21	$13.17
Total	361	100.0%	120.9	100.0%	$168.89	$189.54

The relief provided by a demand resource eligible for emergency energy payments is equal to the estimated load that would have occurred (CBL) less the RT metered load. Table 6-42 shows the total emergency energy credits, by day, paid to demand response resources dispatched during the PAI events on June 14 through June 16, 2022.

Table 6-42 Emergency energy credits

Day	Credits
14-Jun-22	$80,311
15-Jun-22	$221,289
16-Jun-22	$45,571
Total	$347,171

Figure 6-9 through Figure 6-11 show the aggregate emergency energy credits, customer baseline (CBL) and metered load of demand resources dispatched during the PAI events on June 14 through June 16, 2022.

Figure 6-9 Emergency energy credits, CBL and metered load: June 14, 2022

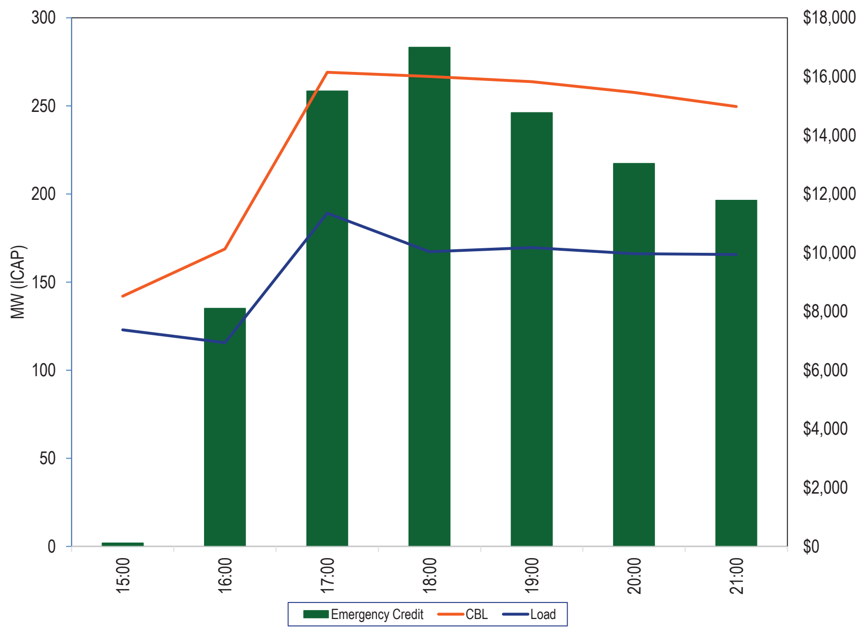


Figure 6-10 Emergency energy credits, CBL and metered load: June 15, 2022

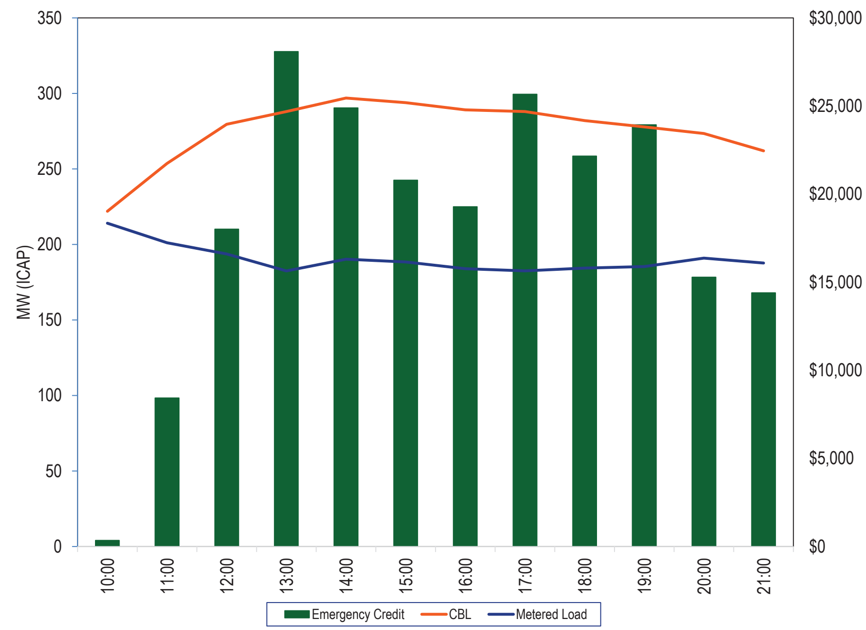
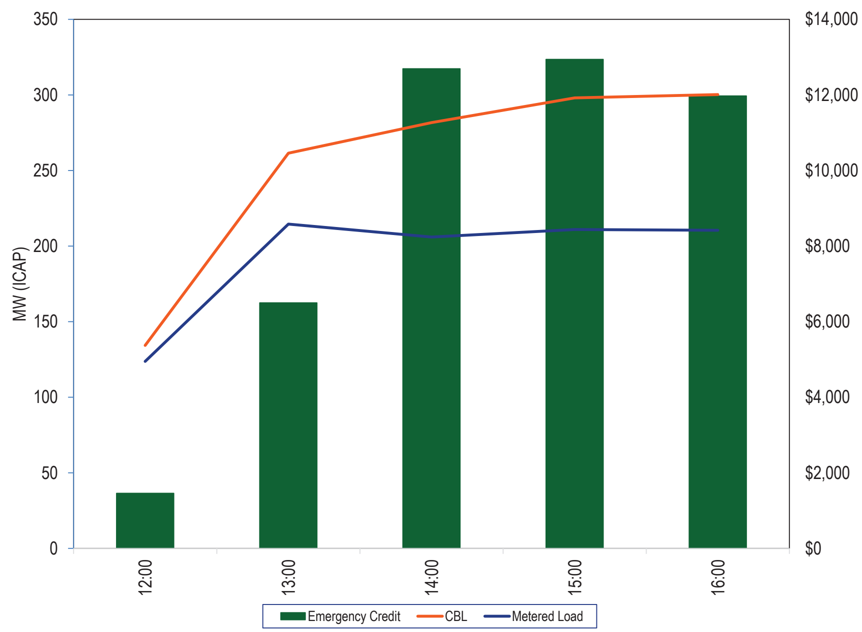


Figure 6-11 Emergency energy credits, CBL and metered load: June 16, 2022



In order to provide relief, a dispatched registration must be operating at a load level below their CBL. Table 6-43 through Table 6-45 show the numbers of registrations, and associated MW quantities, with load below versus above their CBL, by hour, during the PAI events.

Table 6-43 Registration performance vs CBL: June 14, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
15:00	99	29.8	57	10.0
16:00	183	57.2	36	2.6
17:00	213	84.2	31	2.0
18:00	215	102.9	39	0.9
19:00	225	97.6	35	0.9
20:00	225	96.2	33	1.9
21:00	216	89.2	34	2.7

Table 6-44 Registration performance vs CBL: June 15, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
10:00	111	13.6	57	5.4
11:00	200	56.0	35	1.8
12:00	239	89.4	35	1.2
13:00	263	109.1	26	0.9
14:00	256	110.3	39	1.0
15:00	260	109.1	31	0.9
16:00	263	108.8	26	1.0
17:00	257	109.1	28	0.9
18:00	252	101.2	33	1.0
19:00	255	95.8	30	1.0
20:00	238	85.9	33	1.3
21:00	224	78.0	30	1.8

Table 6-45 Registration performance vs CBL: June 16, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
12:00	118	12.7	53	1.9
13:00	214	49.3	35	1.1
14:00	245	78.4	28	0.7
15:00	260	89.7	26	0.3
16:00	266	92.9	21	0.8

Emergency Action Area

The Emergency Action Area for the June 14 through June 16, 2022 performance assessment events, the AEP_MARION Load Management Subzone, is defined by the zip codes shown in Table 6-46.[104]

Table 6-46 AEP_Marion Subzone zip codes

Zone	Subzone	Zip Code		
AEP	MARION	43015	43081	43064
AEP	MARION	43215	43146	43235
AEP	MARION	43125	43035	43220
AEP	MARION	43210	43082	43224
AEP	MARION	43207	43016	43202
AEP	MARION	43228	43026	43223
AEP	MARION	43213	43017	43212
AEP	MARION	43230	43240	43214
AEP	MARION	43085	43204	43232
AEP	MARION	43054	43004	43222
AEP	MARION	43219	43221	43162
AEP	MARION	43229	43209	43227
AEP	MARION	43201	43065	43211
AEP	MARION	43123	43068	43110
AEP	MARION	43205	43231	

Performance Assessment Event – Winter Storm Elliott

At 1730 EPT on December 23, 2022, PJM began issuing Load Management Reduction Actions. Quick Lead Time Pre-Emergency load management resources were required to fully implement their load reductions by 1800 EPT and were released between 2200 and 2215 EPT. Quick Lead Time Emergency load management resources were required to fully implement their load reductions by 1815 EPT and were released at 2130 EPT. Short Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 1900 EPT and were released between 2130 and 2215 EPT. Long Lead Time load management resources were not deployed by PJM on December 23, 2022. The mandatory response time for Capacity Performance DR is limited to June through October and the following May from 10:00AM to 10:00PM EPT (1000 to 2200) and November through April from 6:00AM to 9:00PM EPT (0600 to 2100). Load management resources performing outside of these time periods are not subject to performance assessment but may be eligible for bonus payments.

At 0420 EPT on December 24, 2022, PJM began issuing Load Management Reduction Actions. Long Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 0620 EPT and were released between 1930 and 2030 EPT. Short Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 0600 EPT and were released between 1930 and 2030 EPT. Quick Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 0600 EPT and were released between 1930 and 2030 EPT.

104 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed June 14, 2022).

Table 6-47 Load management action event times: December 23 and 24, 2022

Date	Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)	Zones
23-Dec-22	Pre-Emergency	Quick (30min)	1730	1800	2200	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
			1730	1800	2215	AEP, APS, ATSI, COMED, DAY, DEOK, DOM, DUQ, EKPC, PSEG, RECO
23-Dec-22	Emergency	Quick (30min)	1745	1815	2130	AEP, APS, ATSI, BGE, COMED, DAY, DEOK, DOM, DPL, DUQ, EKPC, JCPL, PECO, PENELEC, PEPCO
23-Dec-22	Emergency	Short (60min)	1800	1900	2130	AEP, ATSI, COMED, DOM, DPL, PENELEC
23-Dec-22	Pre-Emergency	Short (60min)	1800	1900	2200	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
			1800	1900	2215	AEP, APS, ATSI, COMED, DAY, DEOK, DOM, DUQ, EKPC, PSEG
24-Dec-22	Emergency	Long (120 min)	0420	0620	1930	COMED, DAY
			0420	0620	1945	APS, ATSI, DOM
			0420	0620	2015	AEP
			0420	0620	2030	BGE, DPL, PPL
24-Dec-22	Pre-Emergency	Long (120 min)	0420	0620	1930	COMED, DAY, DEOK, DUQ, EKPC
			0420	0620	1945	APS, ATSI, DOM
			0420	0620	2015	AEP, PSEG
			0420	0620	2030	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
24-Dec-22	Emergency	Short (60min)	0500	0600	1930	COMED
			0500	0600	1945	ATSI, DOM
			0500	0600	2015	AEP
			0500	0600	2030	DPL, PENELEC
24-Dec-22	Pre-Emergency	Short (60min)	0500	0600	1930	COMED, DAY, DEOK, DUQ, EKPC
			0500	0600	1945	APS, ATSI, DOM
			0500	0600	2015	AEP, PSEG
			0500	0600	2030	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
24-Dec-22	Emergency	Quick (30min)	0530	0600	1930	COMED, DAY, DEOK, DUQ, EKPC
			0530	0600	1945	APS, ATSI, DOM
			0530	0600	2015	AEP
			0530	0600	2030	BGE, DPL, JCPL, PECO, PENELEC, PEPCO
24-Dec-22	Pre-Emergency	Quick (30min)	0530	0600	1930	COMED, DAY, DEOK, DUQ, EKPC
			0530	0600	1945	APS, ATSI, DOM
			0530	0600	2015	AEP, PSEG, RECO
			0530	0600	2030	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL

On a nominated ICAP basis, there were only 4,940.7 MW of Demand Response dispatched under the Load Management Reduction Actions on December 23, 2022, comprised of 4,565.9 MW of Quick Lead Time and 374.8 MW of Short Lead Time resources. Long Lead Time load management resources (3,721.0 MW) were not deployed by PJM on December 23, 2022, as a result of the combination of the 120 minute lead time and the fact that demand response performance obligations ended at 2100.

Table 6-48 Dispatched demand response resources by lead time: December 23, 2022

	Nominated ICAP (MW)			
Zone	Quick Lead Time	Short Lead Time	Long Lead Time	Total
AECO	45.2	4.3	0.0	49.5
AEP	729.7	121.0	0.0	850.6
APS	374.7	13.2	0.0	388.0
ATSI	388.1	30.3	0.0	418.3
BGE	116.9	6.1	0.0	123.1
COMED	1,125.9	38.4	0.0	1,164.2
DAY	119.9	5.8	0.0	125.7
DEOK	121.6	4.2	0.0	125.8
DOM	220.5	48.3	0.0	268.8
DPL	97.2	4.6	0.0	101.8
DUQ	77.4	7.2	0.0	84.6
EKPC	24.4	18.2	0.0	42.7
JCPL	80.4	3.3	0.0	83.7
METED	113.6	11.8	0.0	125.4
PECO	217.5	16.5	0.0	234.0
PENELEC	97.4	13.1	0.0	110.5
PEPCO	149.5	1.4	0.0	150.9
PPL	255.2	21.8	0.0	277.0
PSEG	208.2	5.3	0.0	213.5
RECO	2.7	0.0	0.0	2.7
Total	4,565.9	374.8	0.0	4,940.7

Included in the 4,940.7 MW of Demand Response resources dispatched on December 23, 2022, were 96.8 MW of Summer Only resources. Summer Only Demand Response resources are not obligated to respond during the months of November through April, but are eligible for bonus payments.

Table 6-49 Annual vs Summer Only Demand Response Resources: December 23, 2022

CP Commitment Type	Number of Registrations	MW (ICAP)
Annual	12,101	4,843.9
Summer Only	1,770	96.8
Total	13,871	4,940.7

On a nominated ICAP basis, there were 8,661.8 MW of Demand Response dispatched under the Load Management Reduction Actions on December 24, 2022, comprised of 4,565.9 MW of Quick Lead Time, 374.8 MW of Short Lead Time and 3,721.0 MW of Long Lead Time resources.

Table 6-50 Dispatched Demand Response Resources by Lead Time: December 24, 2022

	Nominated ICAP (MW)			
Zone	Quick Lead Time	Short Lead Time	Long Lead Time	Total
AECO	45.2	4.3	6.6	56.1
AEP	729.7	121.0	733.3	1,583.9
APS	374.7	13.2	235.2	623.1
ATSI	388.1	30.3	473.3	891.6
BGE	116.9	6.1	43.6	166.7
COMED	1,125.9	38.4	442.7	1,606.9
DAY	119.9	5.8	52.6	178.3
DEOK	121.6	4.2	91.0	216.8
DOM	220.5	48.3	493.6	762.4
DPL	97.2	4.6	153.8	255.6
DUQ	77.4	7.2	38.8	123.3
EKPC	24.4	18.2	218.9	261.6
JCPL	80.4	3.3	30.1	113.8
METED	113.6	11.8	57.3	182.7
PECO	217.5	16.5	82.9	316.9
PENELEC	97.4	13.1	141.9	252.4
PEPCO	149.5	1.4	180.4	331.3
PPL	255.2	21.8	196.0	473.0
PSEG	208.2	5.3	49.0	262.5
RECO	2.7	0.0	0.0	2.7
Total	4,565.9	374.8	3,721.0	8,661.8

Included in the 8,661.8 MW of Demand Response resources dispatched on December 24, 2022, were 487.9 MW of Summer Only resources. Summer Only Demand Response resources are not obligated to respond during the months of November through April, but are eligible for bonus payments.

Table 6-51 Annual vs Summer Only Demand Response Resources: December 24, 2022

CP Commitment Type	Number of Registrations	MW (ICAP)
Annual	14,532	8,173.9
Summer Only	1,781	487.9
Total	16,313	8,661.8

Table 6-52 and Table 6-53 shows the amount of nominated MW and registrations by lead time and reduction method dispatched for December 23 and December 24, 2022. Nominated MW are Pre-Emergency or Emergency

Load Response registrations used to satisfy a CSP's committed MW position for a delivery year.

Table 6-52 Demand Response Resources Called by Lead Time and Reduction Method: December 23, 2022

Product Type	Lead Time	Number of Registrations	Load Backed DR MW (ICAP)	Gen Backed DR MW (ICAP)	Total DR MW (ICAP)
Emergency	Long (120 min)	0	0.0	0.0	0.0
Emergency	Short (60 min)	10	3.8	17.2	21.0
Emergency	Quick (30 min)	229	17.6	174.1	191.7
Pre-Emergency	Long (120 min)	0	0.0	0.0	0.0
Pre-Emergency	Short (60 min)	307	321.3	32.6	353.8
Pre-Emergency	Quick (30 min)	13,325	3,971.9	402.3	4,374.2
Total		13,871	4,314.6	626.1	4,940.7

Table 6-53 Demand Response Resources Called by Lead Time and Reduction Method: December 24, 2022

Product Type	Lead Time	Number of Registrations	Load Backed DR MW (ICAP)	Gen Backed DR MW (ICAP)	Total DR MW (ICAP)
Emergency	Long (120 min)	60	13.4	133.5	146.9
Emergency	Short (60 min)	10	3.8	17.2	21.0
Emergency	Quick (30 min)	229	17.6	174.1	191.7
Pre-Emergency	Long (120 min)	2,382	3,091.7	482.4	3,574.1
Pre-Emergency	Short (60 min)	307	321.3	32.6	353.8
Pre-Emergency	Quick (30 min)	13,325	3,971.9	402.3	4,374.2
Total		16,313	7,419.8	1,242.0	8,661.8

Table 6-54 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices dispatched on December 23 and December 24, 2022. The majority of participants, 80.3 percent of locations and 51.7 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,850 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.8 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $163.04 per location and $132.39 per nominated MW.

Table 6-54 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: December 23 and 24, 2022

Range 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-$1000	119	0.7%	187.1	2.2%	$80.65	$51.31
$1,000-$1,275	2,854	16.9%	3,514.7	41.7%	$163.04	$132.39
$1,275-$1,550	352	2.1%	370.9	4.4%	$42.65	$40.48
$1,550-$1,849	13,523	80.3%	4,353.4	51.7%	$41.89	$130.13
Total	16,848	100.0%	8,426.1	100.0%	$62.71	$125.38

The top four Curtailment Service Providers accounted for 86.6 percent of Demand Response MW dispatched under the Load Management Reduction Actions on December 23, 2022. The top for Curtailment Service Providers accounted for 78.2 percent of Demand Response MW dispatched under the Load Management Reduction Actions on December 24, 2022.

Performance

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).

The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response.

Immediately preceding the call for Load Management resources on December 23, 83 percent of registrations were already at load levels equal to or, below, their Winter Peak Loads. Immediately preceding the call for Load Management resources on December 24th, 90 percent of registrations were already at load levels equal to or, below, their Winter Peak Loads.

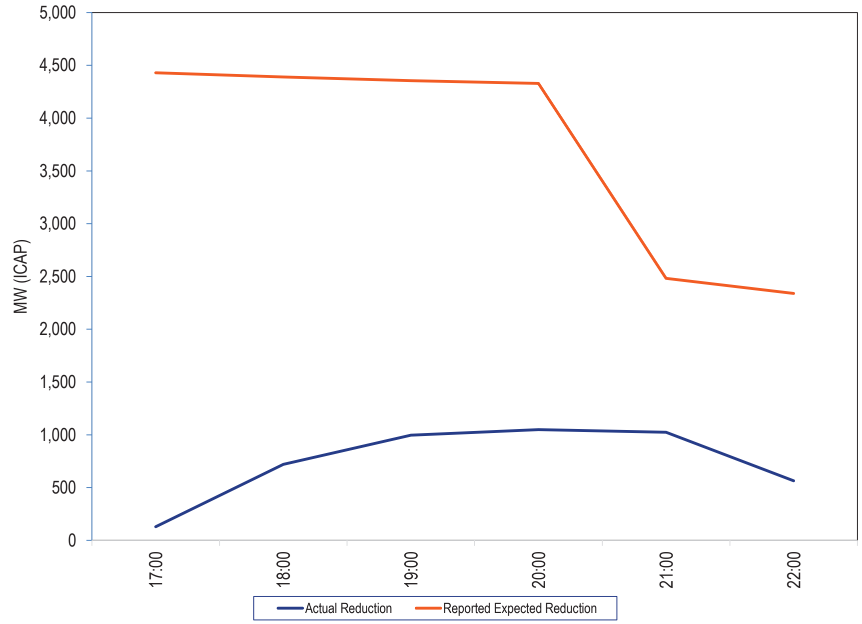
Expected Load Reduction Reporting

CSPs are required to report accurate expected real time energy load reductions by pre emergency/emergency status, lead time, product, and zone.[105] Expected real time energy load reductions are the amount of energy that the CSP expects will be reduced based on the difference between the CBL and expected load. If a registered location's load is already low and will not be reduced further, the CSP should report the expected reduction as zero. Reported expected load reductions do not affect emergency energy settlements. PJM uses the expected load reductions to determine the amount of DR to dispatch and to evaluate the expected response.

Prior to the start of a month, CSPs must upload expected reduction data for all Load Management registrations. Data should be reviewed daily throughout the month and updates, if any, are due by 1600 EPT on the day prior to each operating day. The review and update frequency increases to hourly (from 1000 thru 1900 EPT) when PJM has issued Maximum Emergency Generation or Load Management Alerts or Actions.

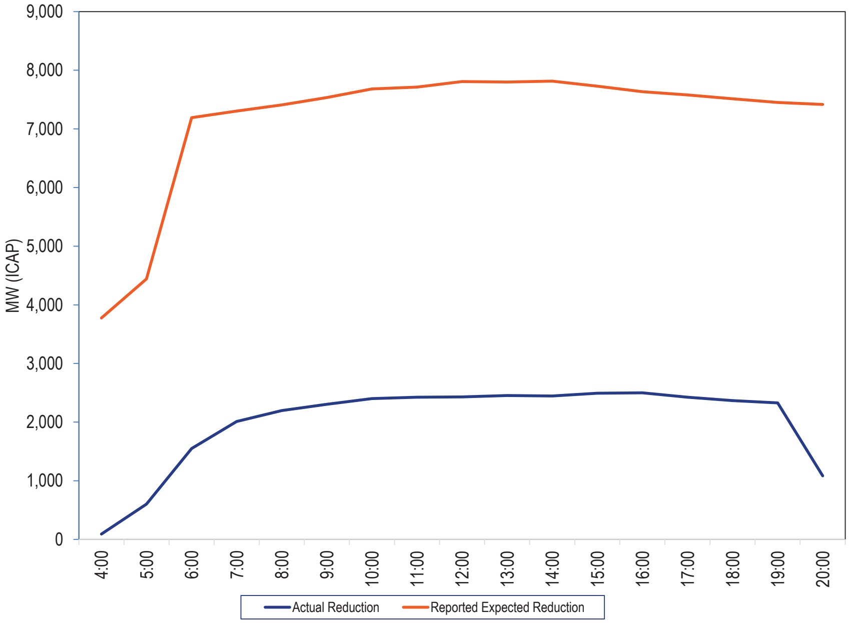
Figure 6-12 and Figure 6-13 show that the CSP forecasted real-time energy reductions were significantly greater than the actual energy load reductions provided on both December 23, 2022, and December 24, 2022.

Figure 6-12 Reported Expected vs Actual Reduction: December 23, 2022



105 See "Expected Reduction Upload Template," <https://pjm.com/-/media/etools/dr-hub/expected-reduction-reporting-template.ashx> (Accessed April 20, 2023).

Figure 6-13 Reported Expected vs Actual Reduction: December 24, 2022



Nonperformance Charges

Nonperformance charge rates are calculated on a modeled LDA basis for the relevant delivery year. The nonperformance charge rate for a specific resource is based on the Net CONE expressed in $/MW-day in ICAP for the LDA in which the resource is modeled and is calculated as:[106]

Nonperformance Charge Rate ($/MW-5-Minute Interval) = [(Net CONE x Number of Days in Delivery Year) / 30 Hours] / 12 Intervals

Table 6-55 shows the nonperformance charge rates for the 2022/2023 Delivery Year.

106 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 55 (Feb. 9, 2023).

Table 6-55 Nonperformance Charge Rates for the 2022/2023 Delivery Year

LDA	Net CONE (ICAP)	Charge Rate
ATSI	$218.79	$221.83
ATSI-CLEVELAND	$218.79	$221.83
BGE	$214.87	$217.85
COMED	$235.27	$238.54
DAY	$214.82	$217.80
DEOK	$212.27	$215.22
DPL-SOUTH	$224.18	$227.29
EMAAC	$246.18	$249.60
MAAC	$232.67	$235.90
PEPCO	$246.34	$249.76
PPL	$237.69	$240.99
PS-NORTH	$254.80	$258.34
PSEG	$254.80	$258.34
RTO	$247.26	$250.69
SWMAAC	$230.61	$233.81

The charge rate is multiplied by the performance shortfall in each PAI to determine the nonperformance financial penalty for committed CP resources.[107] The nonperformance charge is calculated as:[108]

*Nonperformance Charge = Performance Shortfall MW * Nonperformance Charge Rate*

Table 6-56 Nonperformance Charges

Day	Charges
23-Dec-22	$875,477.34
24-Dec-22	$573,754.07
Total	$1,449,231.41

Figure 6-14 and Figure 6-15 show the aggregate nonperformance charge, expected reduction value and actual reduction value, by interval, of demand resources dispatched during the PAI events on December 23 through December 24, 2022.

107 Demand Response performance metrics, unless otherwise noted, exclude those committed to FRR and PRD.
108 The IMM identified a billing error in which PJM assessed nonperformance charges to Demand Resources on December 23rd beyond the end of their mandatory compliance time of 2100 EPT. PJM will correct the issue in the April monthly bill issued in May 2023. The IMM will update the penalty, bonus and overall performance metrics based on PJM's revised billing.

Figure 6-14 Nonperformance charges, expected and actual reduction values: December 23, 2022

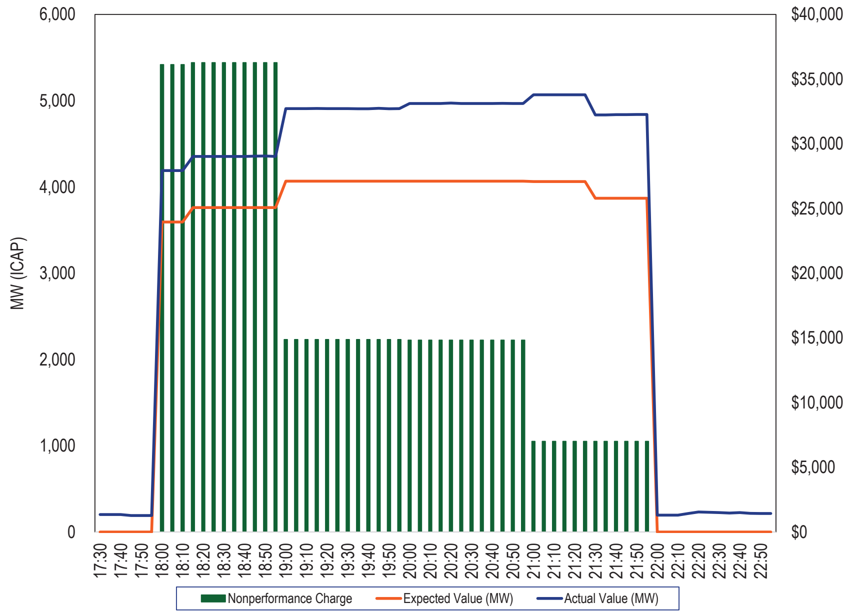
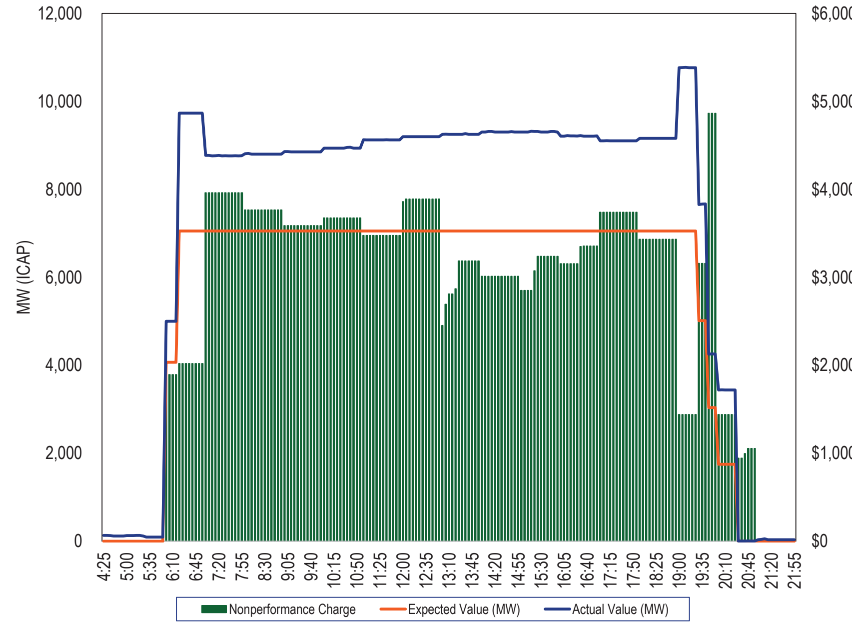


Figure 6-15 Nonperformance charges, expected and actual reduction values: December 24, 2022



Actual performance across all resources in the Emergency Action Area included the performance by resources that did not have a performance obligation, and over performance by some resources that did have a CP obligation. Demand Resources that are not capacity resources do not have an obligation to respond during an emergency and therefore do not contribute to the expected value. Table 6-57 shows the daily average actual performance as a percent of expected performance, with and without the contribution of resources that did not have an obligation to perform (non-CP resources).

Table 6-57 Daily average actual performance as a percent of expected performance: December 23 and 24, 2022

Day	Including non-CP resources	Excluding non-CP resources
23-Dec-22	120.9%	116.1%
24-Dec-22	132.0%	126.2%

Bonus Performance

A resource with actual performance above its expected performance is assigned a share of the collected nonperformance charge revenues as a bonus performance credit. When calculating bonus megawatts, the actual performance of a dispatchable resource is capped at the megawatt level at which the resource was scheduled and dispatched by PJM during the performance assessment event.

The expected and actual performance calculations for bonus megawatt evaluations for load DR is:[109]

Expected Performance = CP Capacity Commitment (ICAP)

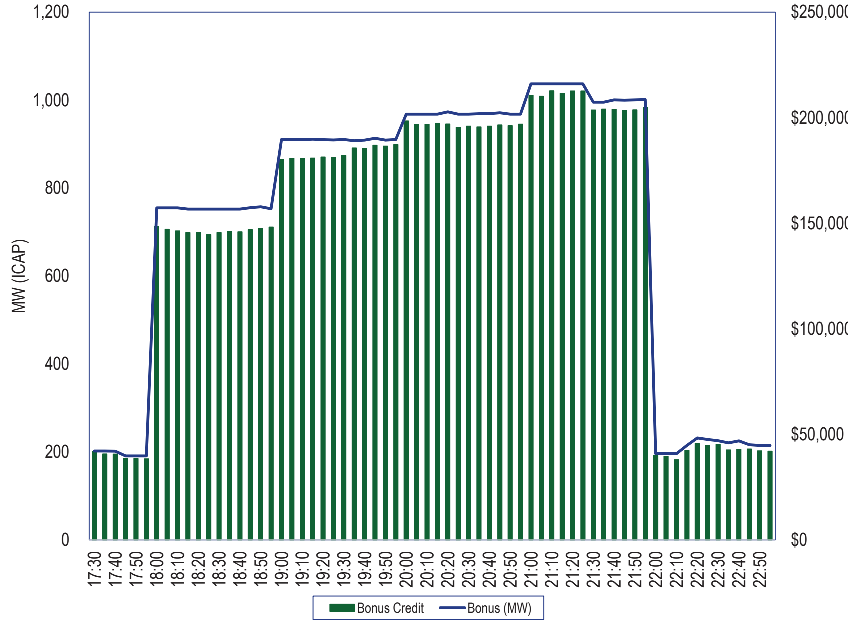
Actual Performance = Load Reduction + Reserve/Regulation Assignment

Table 6-58 Bonus Credits

Day	Bonus
23-Dec-22	$9,557,942.71
24-Dec-22	$69,341,298.87
Total	$78,899,241.58

Figure 6-6 through Figure 6-8 show the bonus MW and bonus credit, by interval, of demand resources dispatched during the PAI events on December 23 and 24, 2022.

Figure 6-16 Bonus performance by interval: December 23, 2022



109 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).

Figure 6-17 Bonus performance by interval: December 24, 2022

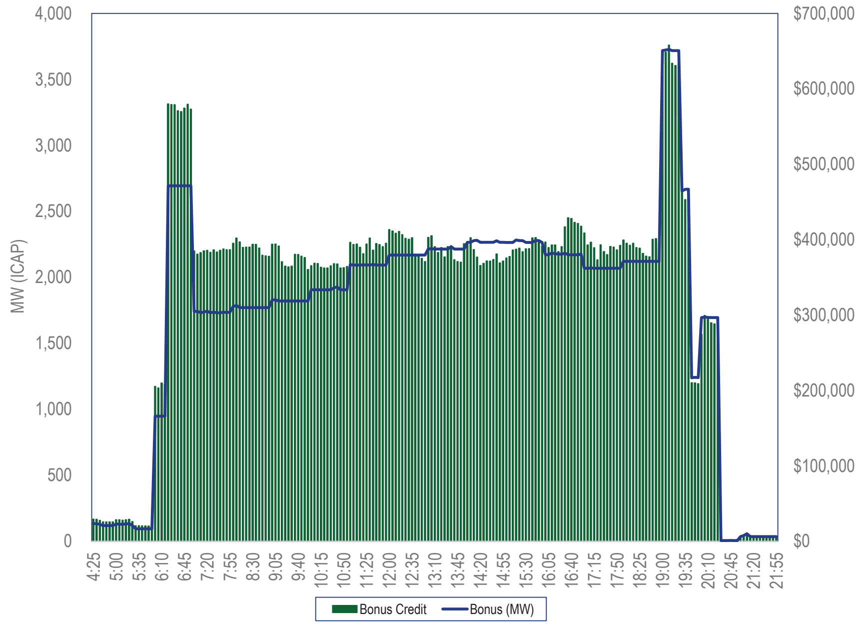
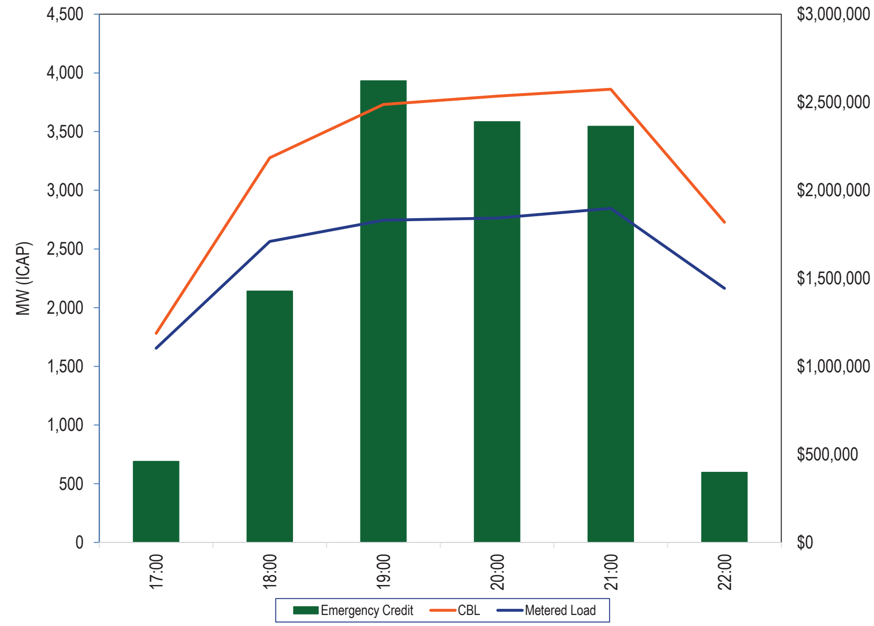


Figure 6-18 Emergency energy credits, CBL and metered load: December 23, 2022



Emergency Energy Credits

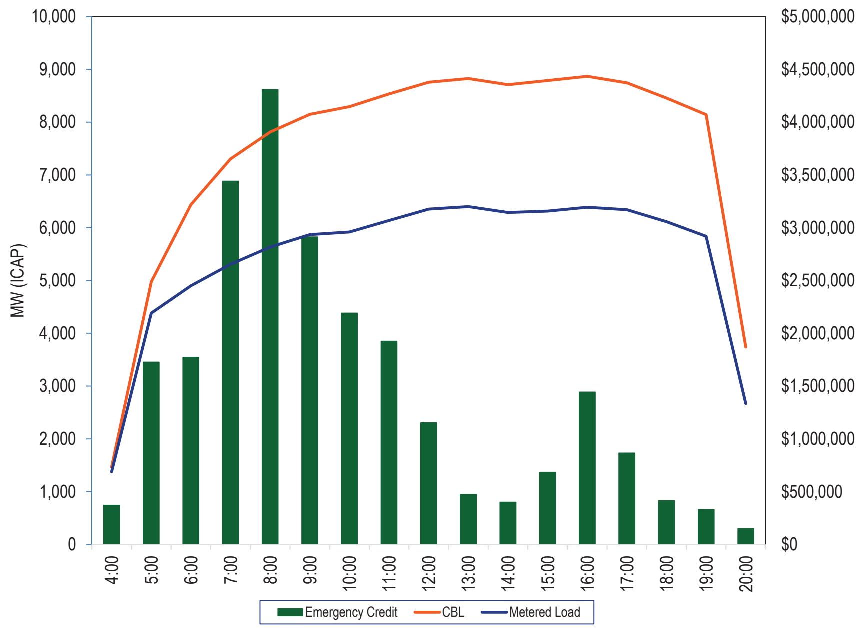
Table 6-59 shows the total emergency energy credits, by day, paid to demand response resources dispatched during the PAI events on December 23 and 24, 2022.

Table 6-59 Emergency energy credits: December 23 and 24, 2022

Day	Credits
23-Dec-22	$9,660,329
24-Dec-22	$24,560,940
Total	$34,221,268

Figure 6-18 and Figure 6-19 show the aggregate emergency energy credits, customer baseline and metered load of demand resources dispatched during the PAI events on December 23 and 24, 2022.

Figure 6-19 Emergency energy credits, CBL and metered load: December 24, 2022



In order to provide relief, a dispatched registration must be operating at a load level below their CBL. Table 6-60 and Table 6-61 show the numbers of registrations, and associated MW quantities, with load below versus above their CBL, by hour, during the PAI events.

Table 6-60 Registration performance vs CBL: December 23, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
17:00	1,726	186.2	1,066	57.0
18:00	3,487	768.9	1,059	48.9
19:00	4,101	1,050.6	1,047	54.2
20:00	4,325	1,112.3	1,126	63.3
21:00	4,369	1,087.5	1,190	64.1
22:00	2,604	618.1	874	53.3

Table 6-61 Registration performance vs CBL: December 24, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
4:00	4,852	657.7	1,554	56.7
6:00	6,200	1,587.3	1,416	38.1
7:00	7,186	2,048.5	1,309	36.7
8:00	8,129	2,254.6	1,137	57.6
9:00	8,825	2,345.7	1,096	40.6
10:00	9,386	2,437.8	1,078	35.6
11:00	9,719	2,463.3	1,113	38.0
12:00	9,900	2,494.3	1,186	63.5
13:00	10,106	2,507.4	1,208	53.9
14:00	10,252	2,514.8	1,209	67.8
15:00	10,336	2,553.1	1,214	59.6
16:00	10,414	2,551.6	1,163	51.9
17:00	10,187	2,478.7	1,292	53.7
18:00	10,216	2,440.3	1,124	72.4
19:00	9,954	2,392.7	1,111	64.3
20:00	5,020	1,134.1	526	50.1

PRD

PRD compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point where demand reduction is expected.[110] A PRD registration is not assessed when the PRD Curve associated with such registration in the real-time energy market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval. The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's Peak Load Contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the Peak Load Contribution. The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration. For each registration in an Emergency Action Area, the Actual Performance is equal to the actual load reduction for such registration for the Performance Assessment Interval. The Actual Performance for a PRD Provider in the Emergency Action Area for the Performance Assessment Interval is

110 See "PJM Manual 18: PJM Capacity Market," § 3A.6.2A, Rev. 55 (Feb. 9, 2023).

equal to the sum of the Actual Performance of the PRD registrations that were measured for compliance for such Emergency Action Area and Performance Assessment Interval. The Expected Performance for a PRD Provider for the Emergency Action Area and Performance Assessment Interval is equal to the Nominal PRD Value committed by the PRD Provider in the Emergency Action Area, adjusted to account for any PRD registrations in the Emergency Action Area that were not subject to compliance measurement. The Performance Shortfall for a PRD Provider is calculated as the Expected Performance minus the Actual Performance. Unlike Demand Response resources registered in the full program option, PRD registrations are not eligible for emergency energy settlements.

Figure 6-20 PRD Nonperformance charges, expected and actual reduction values: December 23, 2022

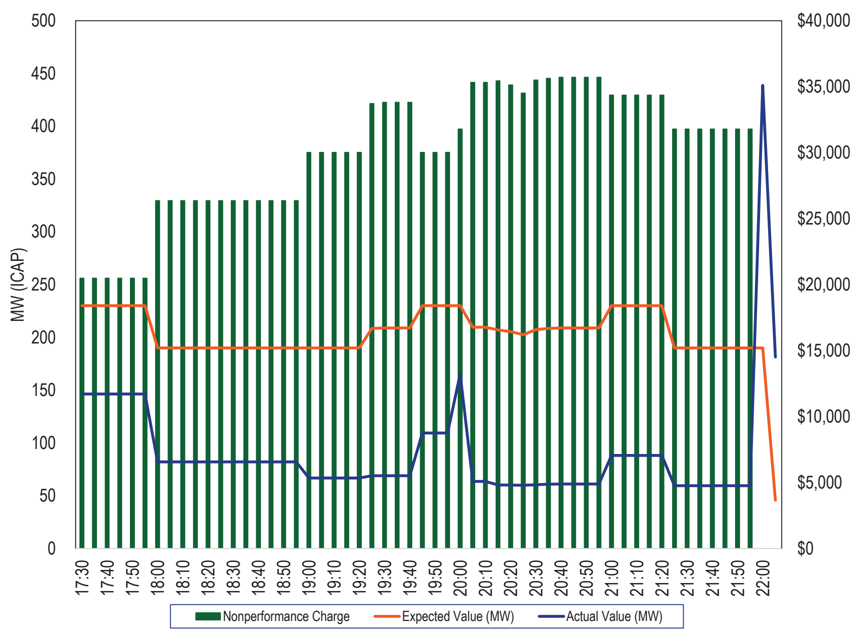


Figure 6-21 PRD Nonperformance charges, expected and actual reduction values: December 24, 2022

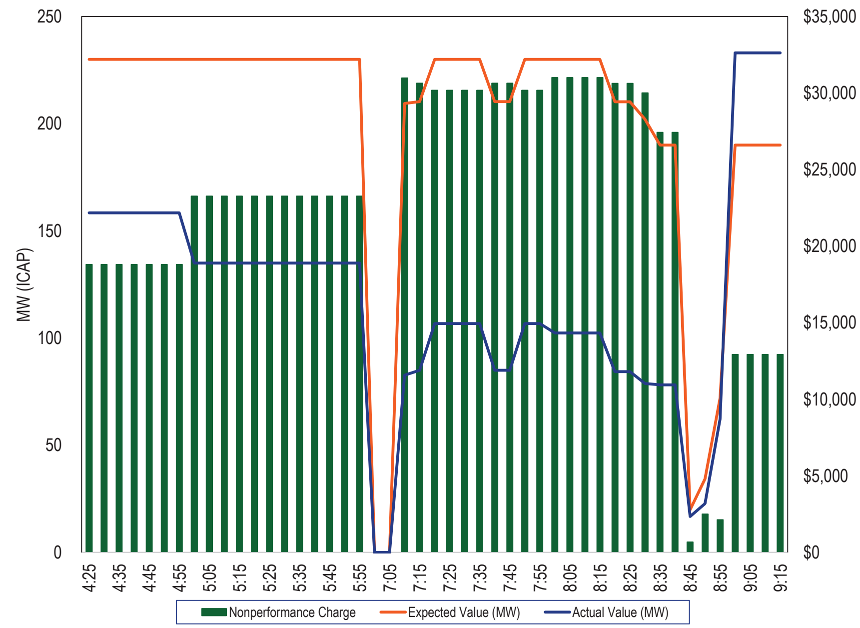


Table 6-62 shows the average daily performance of PRD resources on December 23 and 24, 2022.

Table 6-62 PRD Daily average actual performance as a percent of expected performance: December 23 and 24, 2022

Day	Percent Performance
23-Dec-22	49.7%
24-Dec-22	60.7%

Table 6-63 shows the daily nonperformance charges for PRD resources on December 23 and 24, 2022.

Table 6-63 PRD Nonperformance Charges: December 23 and 24, 2022

Day	Charges
23-Dec-22	$1,630,413.84
24-Dec-22	$1,042,231.96
Total	$2,672,645.80

Table 6-64 shows the daily bonus performance credits of PRD resources on December 23 and 24, 2022.

Table 6-64 PRD Bonus Credits: December 23 and 24, 2022

Day	Bonus
23-Dec-22	$93,208.55
24-Dec-22	$87,887.83
Total	$181,096.38

Energy Efficiency

The Expected Performance of an Energy Efficiency resource during a Performance Assessment Interval is determined as the resources' committed capacity without making any adjustment for the Forecast Pool Requirement. The actual performance of an Energy Efficiency resource with an RPM Capacity Performance commitment is not measured during a Performance Assessment Interval. The Actual Performance of an Energy Efficiency resource Energy Efficiency Resource is determined as the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation M&V Report.[111] Any approved M&V quantity in excess of the resource's Expected Performance during a Performance Assessment event is treated as Actual Performance, and is eligible for bonus credits. No Energy Efficiency resources were assessed a nonperformance charge during December 23 and 24, 2022. Energy Efficiency resources in aggregate, were credited with 1,710.8 MW, 34.3 percent in excess of their RPM committed values per interval, during December 23 and 24, 2022. Due to the compressed RPM auction schedule, only two of the four otherwise eligible Energy Efficiency Installation period's resources were eligible to offer into the 2022/2023 RPM Base Residual Auction. The ineligible installation period resources were however eligible to be included in the participant's 2022/2023 Post-Installation M&V reports. This approved resource capability in excess of the participant's RPM commitment contributed to the excess Actual Performance, and subsequent bonus payments, to Energy Efficiency resources on December 23 and 24, 2022.

111 See "PJM Manual 18: PJM Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).

Table 6-65 EE Daily Percent Performance, Shortfall and Bonus: December 23 and 24, 2022

Day	Expected Performance MW	Actual Performance MW	Shortfall MW	Bonus MW	Bonus MW Percent of Expected Performance	Bonus Credits
23-Dec-22	4,987.5	6,698.3	0.0	1,710.8	34.3%	$22,607,295.74
24-Dec-22	4,987.5	6,698.3	0.0	1,710.8	34.3%	$68,925,583.76