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 increased by $155.9 million, 43.4 percent, from $359.2 million in 2020 to $515.1 million in 2021. Emergency demand response revenue accounted for 97.9 percent of all demand response revenue, economic demand response for 0.1 percent, demand response in the synchronized reserve market for 1.5 percent and demand response in the regulation market for 0.4 percent.

  Total emergency demand response revenue increased by $149.4 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in 2021.[2]

  Economic demand response revenue increased by $0.4 million, 128.4 percent, from $0.3 million in 2020 to $0.8 million in 2021.[3] Demand response revenue in the synchronized reserve market increased by $5.2 million, 215.1 percent, from $2.4 million in 2020 to $7.6 million in2021. Demand response revenue in the regulation market increased by $1.0 million, 70.8 percent, from $1.4 million in 2020 to $2.3 million in 2021.

- **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 2020 and 2021. The HHI for economic resource reductions decreased by 539 points from 9065 for 2020 to 8526 in 2021. The ownership of emergency load response resources was highly concentrated in 2020. The HHI for emergency load response committed MW was 2523 for the 2020/2021 Delivery Year. In the 2020/2021 Delivery Year, the four largest CSPs owned 88.4 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2584 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs own 89.0 percent of all committed demand response UCAP MW.

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

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 for demand resources were downloaded on January 10, 2022 and may change as a result of continued PJM billing updates.

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

4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 85 (Sep. 1, 2021).

Recommendations

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)

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

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 demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 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. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations. (Priority: Medium. New recommendation. 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.

Conclusion

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

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

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

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

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

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

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

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

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

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

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[8] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will 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. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement

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 March 6, 2019).

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 March 6, 2019).

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).

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

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

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

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic, emergency and pre-emergency programs, or Price Responsive Demand (PRD). Table 6-1 provides an overview of the key features of PJM demand response programs.

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

FERC Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[14] PJM implemented rules that require PJM to verify with EDCs that no law or 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.

12 577 U.S. 260 (2016).

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

14 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

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.

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	Limited, Annual, Base, Capacity Performance, Summer-Period Capacity Performance OATT Attachmend DD § 5.5A	Limited, Annual, Base, 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 Attachmnt 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

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 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.

PJM Demand Response Programs

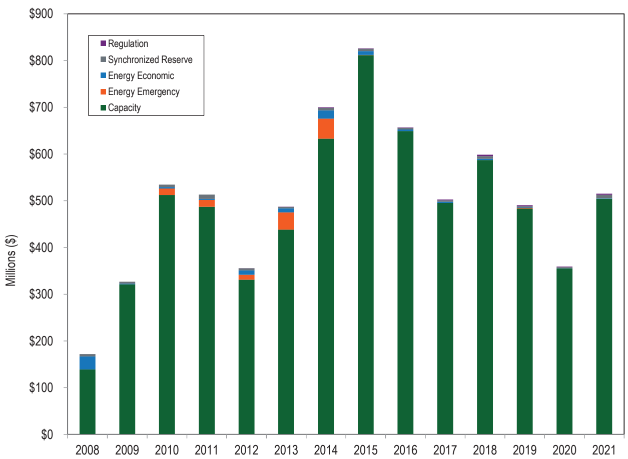
Figure 6-1 shows all revenue from PJM demand response programs by market for 2008 through 2021. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[17] In 2021, total demand response revenue increased by $155.9 million, 43.4 percent, from $359.2 million in 2020 to $515.1 million in 2021. Total emergency demand response revenue increased by $149.2 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in 2021. This increase consisted of capacity market revenue.[18] In 2021, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 97.9 percent of all revenue received by demand response providers, the economic program for 0.1 percent, synchronized reserve for 1.5 percent and the regulation market for 0.4 percent.

17 This includes both capacity market revenue and emergency energy revenue for capacity resources.
18 The total credits and MWh for demand resources were downloaded on January 10, 2022 and may change as a result of continued PJM billing updates.

Economic demand response revenue increased by $0.4 million, 128.4 percent, from $0.3 million in 2020 to $0.8 million in2021.[19] Demand response revenue in the synchronized reserve market increased by $5.2 million, 215.1 percent, from $2.4 million in 2020 to $7.6 million in 2021. Demand response revenue in the regulation market increased by $1.0 million, 70.8 percent, from $1.4 million in 2020 to $2.3 million in 2021.

Higher demand resource revenues were in part a result of higher capacity market prices in the 2020/2021 RPM and 2021/2022 RPM auctions compared to capacity market prices in 2019/2020.

Figure 6-1 Demand response revenue by market for 2008 to 2021



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.[20] 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.[21]

All capacity resources must respond during a Performance Assessment Interval (PAI). Demand resources are the only capacity performance resource that create 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 a other capacity resources. All other capacity resources must offer daily into the day-ahead energy market.

19 Economic credits are synonymous with revenue received for reductions under the economic load response program.
20 OA Schedule 1 § 8.5.
21 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM. *See* PJM OATT RAA Article 1.

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.[22]

Market Structure

The HHI for demand resources showed that ownership was highly concentrated for the 2020/2021 Delivery Year, with an HHI value of 2523. In the 2020/2021 Delivery Year, the four largest companies contributed 88.4 percent of all committed demand resources UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2021/2022 Delivery Year, with an HHI value of 2584. In the 2021/2022 Delivery Year, the four largest companies own 89.0 percent of all committed demand response UCAP MW.

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: 2020/2021 and 2021/2022 Delivery Years[23]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2020/2021	ATSI	719.8	2488	High
	ATSI-CLEVELAND	231.9	4438	High
	BGE	249.5	2344	High
	COMED	1,657.3	2819	High
	DAY	241.5	3648	High
	DEOK	184.7	3727	High
	DPL-SOUTH	72.6	3807	High
	EMAAC	757.3	2676	High
	MAAC	557.8	2905	High
	PEPCO	236.3	2921	High
	PPL	616.6	2694	High
	PS-NORTH	152.7	3213	High
	PSEG	186.3	2501	High
	RTO	3,581.4	2681	High
2021/2022	ATSI	924.0	2873	High
	ATSI-CLEVELAND	272.8	5910	High
	BGE	279.0	2363	High
	COMED	2,073.7	2769	High
	DAY	227.7	3042	High
	DEOK	220.5	2167	High
	DPL-SOUTH	66.3	5289	High
	EMAAC	904.7	2365	High
	MAAC	750.0	2539	High
	PEPCO	345.9	2625	High
	PPL	697.7	2747	High
	PS-NORTH	188.6	3641	High
	PSEG	221.9	2412	High
	RTO	4,254.9	2874	High

Market Performance

Table 6-3 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM increased by 1,982.0 MW, or 21.0 percent, from 9,445.7 MW in the 2020/2021 Delivery Year to 11,427.7 MW in the 2021/2022 Delivery Year. The DR percent of capacity increased by 1.1 percentage points, from 5.4 percent in the 2020/2021 Delivery Year to 6.5 percent in the 2021/2022 Delivery Year.

22 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).

23 The RTO LDA refers to the rest of RTO.

Table 6-3 Cleared Demand Resource UCAP MW: 2007/2008 through 2021/2022 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%

Table 6-4 shows zonal monthly capacity market revenue to demand resources for 2021. Capacity market revenue increased in 2021 by $149.4 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in2021. The capacity revenue amounts for 2020 include five months from the 2019/2020 Delivery Year and seven months from the 2020/2021 delivery year and the capacity revenue amounts for 2021 include five months from the 2020/2021 Delivery Year and seven months from the 2021/2022 Delivery Year.

Table 6-4 Zonal monthly demand resource capacity revenue: 2021

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
ACEC	$364,810	$329,506	$364,810	$353,042	$364,810	$414,657	$428,479	$428,479	$414,657	$428,479	$414,657	$428,479	$4,734,865
AEP, EKPC	$3,309,544	$2,989,265	$3,309,544	$3,202,784	$3,309,544	$7,761,321	$8,020,032	$8,020,032	$7,761,321	$8,020,032	$7,761,321	$8,020,032	$71,484,771
APS	$1,790,204	$1,616,959	$1,790,204	$1,732,456	$1,790,204	$4,296,522	$4,439,739	$4,439,739	$4,296,522	$4,439,739	$4,296,522	$4,439,739	$39,368,550
ATSI	$1,882,518	$1,700,339	$1,882,518	$1,821,792	$1,882,518	$5,909,358	$6,106,337	$6,106,337	$5,909,358	$6,106,337	$5,909,358	$6,106,337	$51,323,107
BGE	$468,186	$422,877	$468,186	$453,083	$468,186	$1,170,553	$1,209,572	$1,209,572	$1,170,553	$1,209,572	$1,170,553	$1,209,572	$10,630,463
COMED	$8,465,782	$7,646,513	$8,465,782	$8,192,692	$8,465,782	$10,830,893	$11,191,922	$11,191,922	$10,830,893	$11,191,922	$10,830,893	$11,191,922	$118,496,919
DAY	$465,983	$420,888	$465,983	$450,951	$465,983	$956,340	$988,218	$988,218	$956,340	$988,218	$956,340	$988,218	$9,091,680
DOM	$1,791,652	$1,618,266	$1,791,652	$1,733,857	$1,791,652	$4,805,706	$4,965,896	$4,965,896	$4,805,706	$4,965,896	$4,805,706	$4,965,896	$43,007,783
DPL	$972,021	$877,954	$972,021	$940,665	$972,021	$1,004,324	$1,037,801	$1,037,801	$1,004,324	$1,037,801	$1,004,324	$1,037,801	$11,898,858
DUKE	$586,115	$529,394	$586,115	$567,208	$586,115	$801,363	$828,075	$828,075	$801,363	$828,075	$801,363	$828,075	$8,571,334
DUQ	$383,237	$346,149	$383,237	$370,874	$383,237	$568,680	$587,636	$587,636	$568,680	$587,636	$568,680	$587,636	$5,923,318
JCPLC	$817,686	$738,555	$817,686	$791,309	$817,686	$846,714	$874,938	$874,938	$846,714	$874,938	$846,714	$874,938	$10,022,816
MEC	$644,939	$582,525	$644,939	$624,134	$644,939	$1,519,890	$1,570,553	$1,570,553	$1,519,890	$1,570,553	$1,519,890	$1,570,553	$13,983,358
PE	$826,762	$746,753	$826,762	$800,092	$826,762	$1,542,009	$1,593,409	$1,593,409	$1,542,009	$1,593,409	$1,542,009	$1,593,409	$15,026,795
PECO	$2,133,013	$1,926,593	$2,133,013	$2,064,206	$2,133,013	$2,219,456	$2,293,438	$2,293,438	$2,219,456	$2,293,438	$2,219,456	$2,293,438	$26,221,961
PEPCO	$432,443	$390,594	$432,443	$418,494	$432,443	$947,100	$978,670	$978,670	$947,100	$978,670	$947,100	$978,670	$8,862,398
PPL	$1,594,416	$1,440,118	$1,594,416	$1,542,983	$1,594,416	$2,884,710	$2,980,867	$2,980,867	$2,884,710	$2,980,867	$2,884,710	$2,980,867	$28,343,948
PSEG	$1,901,994	$1,717,930	$1,901,994	$1,840,640	$1,901,994	$2,503,407	$2,586,854	$2,586,854	$2,503,407	$2,586,854	$2,503,407	$2,586,854	$27,122,191
REC	$22,613	$20,424	$22,613	$21,883	$22,613	$28,837	$29,798	$29,798	$28,837	$29,798	$28,837	$29,798	$315,851
TOTAL	$28,853,918	$26,061,603	$28,853,918	$27,923,146	$28,853,918	$51,011,841	$52,712,236	$52,712,236	$51,011,841	$52,712,236	$51,011,841	$52,712,236	$504,430,968

Pre-Emergency and Emergency Load Response resources must register all resources to respond within 30, 60 or 120 minutes of a PJM dispatched event. The quick lead time, or 30 minute lead time, is the default lead time, unless a CSP submits an exception request for 60 or 120 minute notification time based on a physical constraint.[24] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18.[25] Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-5 shows the amount of nominated MW and locations by product type and lead time for the 2020/2021 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 3,096 locations, or 21.2 percent of all locations, which have 3,548.6.0 nominated MW, or 45.0 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2020/2021 Delivery Year.

24 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 51 (Oct. 20, 2021).
25 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 49 (Aug. 2021).

Table 6-5 Nominated MW and locations by product type and lead time: 2020/2021 Delivery Year

	Pre-Emergency MW		Emergency MW		
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	4,097.2	4,097.2	240.6	240.6	4,337.9
Short Lead (60 Minutes)	326.9	326.9	28.8	28.8	355.7
Long Lead (120 Minutes)	3,043.0	3,043.0	150.0	150.0	3,192.9
Total	7,467.1	7,467.1	419.4	419.4	7,886.5
	Pre-Emergency Locations		Emergency Locations		
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	11,025	11,025	473	473	11,498
Short Lead (60 Minutes)	316	316	39	39	355
Long Lead (120 Minutes)	2,466	2,466	275	275	2,741
Total	13,807	13,807	787	787	14,594

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2021/2022 Delivery Year. PJM approved 3,208 locations, or 20.9 percent of all locations, which have 3,645.6 nominated MW, or 45.7 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2021/2022 Delivery Year.

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

	Pre-Emergency MW		Emergency MW				
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total	Emergency Total	Total
Quick Lead (30 Minutes)	4,115.5	4,115.5	214.8	214.8	4,330.2	0.0	0.0
Short Lead (60 Minutes)	285.5	285.5	21.0	21.0	306.5	0.0	0.0
Long Lead (120 Minutes)	3,198.2	3,198.2	140.8	140.8	3,339.1	0.0	0.0
Total	7,599.2	7,599.2	376.6	376.6	7,975.8	0.0	0.0
	Pre-Emergency Locations		Emergency Locations				
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total	Emergency Total	Total
Quick Lead (30 Minutes)	11,699	11,699	458	458	12,157	0	0
Short Lead (60 Minutes)	334	334	37	37	371	0	0
Long Lead (120 Minutes)	2,650	2,650	187	187	2,837	0	0
Total	14,683	14,683	682	682	15,365	0	0

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).[26] 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.[27] 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.[28] 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.[29]

26 Real-time load is hourly metered load.

27 135 FERC ¶ 61,212 (2011).
28 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 51 (Oct. 20, 2021).
29 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 51 (Oct. 20, 2021).

The capacity market is an annual market. A Capacity Performance resource has an annual commitment. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of 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.[30] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[31] 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.[32] 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 6-7 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 6-7 Reduction 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	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,225.2	1,954.3	196.0	689.4	3,851.0	17.7	40.6	7,974.3	99.98%
Guaranteed Load Drop	0.3	1.0	0.0	0.0	0.0	0.0	0.3	1.5	0.02%
Total	1,225.5	1,955.3	196.0	689.4	3,851.0	17.7	40.9	7,975.8	100.0%
Percent by method	15.4%	24.5%	2.5%	8.6%	48.3%	0.2%	0.5%	100.0%	

Table 6-8 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, 1,225.5 MW of the 7,975.8 nominated MW, 15.4 percent, used onsite generation. Of the 1,225.5 MW, 84.0 percent used diesel and 16.0 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-8 Onsite generation fuel type (MW): 2021/2022 Delivery Year

	2021/2022	
Fuel Type	MW	Percent
Diesel	1,029.9	84.0%
Natural Gas, Gasoline, Oil, Propane, Waste Products	195.6	16.0%
Total	1,225.5	100.0%

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

Table 6-9 shows the MW registered by measurement and verification method and by technology type for the 2020/2021 Delivery Year. For the 2020/2021 Delivery Year, 99.9 percent use the FSL method and 0.1 percent use the GLD measurement and verification method.

respond. PJM does not measure compliance when demand response is dispatched in a subzone created on the same day as the dispatch. Subzonal dispatch creates a PAI for the subzone, even if PJM does not measure compliance for demand resources.

Table 6-9 Reduction MW by each demand response method: 2020/2021 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	1,219.5	1,877.5	196.4	689.8	3,790.6	61.6	44.9	7,880.4	99.9%
Guaranteed Load Drop	0.3	1.1	0.0	0.0	4.4	0.0	0.3	6.1	0.1%
Total	1,219.7	1,878.6	196.4	689.8	3,795.1	61.6	45.2	7,886.5	100.0%
Percent by method	15.5%	23.8%	2.5%	8.7%	48.1%	0.8%	0.6%	100.0%	

Table 6-10 shows the fuel type used in the onsite generators for the 2020/2021 Delivery Year in the emergency and pre-emergency programs. For the 2020/2021 Delivery Year, 1,219.7 MW of the 7,886.5 nominated MW, 15.5 percent, use onsite generation. Of the 1,219.7 MW, 87.0 percent use diesel and 13.0 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-10 Onsite generation fuel type (MW): 2020/2021 Delivery Year

	2020/2021	
Fuel Type	MW	Percent
Diesel	1,061.4	87.0%
Natural Gas, Gasoline, Oil, Propane, Waste Products	158.3	13.0%
Total	1,219.7	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity Performance 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.[33] A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, the entire registration must

33 OATT Attachment DD, Section 11.

There are currently five dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, and JCPL_REDBANK.[34] Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance, which does not require predefined subzones for mandatory dispatch.[35]

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

34 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed March 4, 2022).

35 OATT Attachment DD, Section 10A.

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>.

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 RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs.

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 or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance.

Capacity Performance 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 Performance 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. Each capacity performance demand response product should measure compliance on a five minute basis to accurately report reductions during demand response events. The current rules for demand response use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each five minute interval of the event and is inconsistent with the measurement of generation resources. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance.[38]

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).[39] 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 6-11 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2020/2021 and 2021/2022 Delivery Years. There are 10,283.9 nominated MW of demand response for the 2021/2022 Delivery Year, 51.0 percent of the required reserve margin and 36.7 percent of the actual reserve margin for the 2021/2022 Delivery Year.[40]

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," § 8.7A, Rev. 51 (Oct. 20, 2021).
39 OATT § 1 (Performance Assessment Hour).
40 *2021 State of the Market Report for PJM: January through June*, Section 5: Capacity, Table 5-7.

Table 6-11 Demand response nominated MW compared to reserve margin: 2020/2021 and 2021/2022 Delivery Years[41]

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
2020/2021	8,524.2	21,127.9	40.3%	33,039.8	25.8%
2021/2022	10,283.9	20,176.5	51.0%	28,005.0	36.7%

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).[42 43] 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.

41 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.

42 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clear 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.

43 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 51 (Oct. 20, 2021).

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. PJM's interpretation of load management event rules allows over compliance to be reported when there is no actual over compliance. Settlement locations with a negative load reduction value (load increase) are not netted by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a negative performance value. PJM limits compliance shortfall values to zero MW. This is not explicitly stated in the Tariff or supporting Manuals and the compliance formulas for FSL and GLD customers do allow negative values.[44]

Limiting compliance to only positive values incorrectly calculates compliance. For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

44 OA Schedule 1 § 8.9.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[45] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

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.[46] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage. The MMU recommends the RRMSE test be required for all demand resources with a CBL.

45 OA Schedule 1 § 8.9.

46 157 FERC ¶ 61,067 (2016).

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends capping demand reductions based entirely on behind the meter generation at the lower of economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[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

47 OA Schedule 1 § 8.2.

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.[50] A CSP picks the testing day, for one hour, on any non-holiday weekday during the applicable mandatory window. A CSP is able to retest if a resource fails to provide the required reduction by less than 25 percent. 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 6-12 shows the test penalties by delivery year by product type for the 2016/2017 Delivery Year through the 2020/2021 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. The testing window is open through the end of the delivery year.

Table 6-12 Test penalties by delivery year by product type: 2016/2017 through 2020/2021

	2016/2017			2017/2018			2018/2019			2019/2020			2020/2021		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	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
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

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. 51 (Oct. 20, 2021).

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.

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 2021/2022 Delivery Year registered under the full program option. There are 1.9 percent of nominated MW for the 2021/2022 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[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 6-13 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2020/2021 Delivery Year. The majority of participants, 76.2 percent of locations and 52.8 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2020/2021 Delivery Year. Almost all registrations, 98.3 percent of locations and 97.1 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 $156.16 per location and $137.58 per nominated MW.

Table 6-13 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2020/2021 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	243	1.7%	222.4	2.9%	$68.14	$30.96
$1,000-$1,275	2,763	19.5%	3,102.7	39.9%	$156.16	$137.58
$1,275-$1,550	356	2.5%	345.0	4.4%	$53.78	$55.49
$1,550-$1,849	10,792	76.2%	4,099.2	52.8%	$55.80	$146.91
Total	14,154	100.0%	7,769.3	100.0%	$75.55	$137.65

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, 77.4 percent of locations and 52.2 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the

52 *Id.*
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. 39 (Jan. 18, 2022).

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 have the highest average at $162.68 per location and $143.75 per nominated MW.

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

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	107	0.7%	207.8	2.7%	$97.45	$20.58
$1,000-$1,275	2,898	19.4%	3,214.4	41.3%	$162.68	$143.75
$1,275-$1,550	370	2.5%	295.3	3.8%	$43.71	$54.76
$1,550-$1,849	11,529	77.4%	4,059.1	52.2%	$50.71	$144.03
Total	14,904	100.0%	7,776.7	100.0%	$72.64	$139.22

PRD

The PRD rules are more aligned with the Capacity Performance construct effective December 30, 2019, although the rules still fall short.[58] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[59] 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 will correctly value 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.[60]

PJM's filing still fell short of completely aligning PRD with the Capacity Performance product. PRD resources will not have to respond during a PAI if the PAI'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.

PRD does not receive direct capacity or energy payments. PRD reduces the amount of capacity that must be purchased by the LSE and therefore reduces the LSE's payments for capacity. When PRD load is not on the system, that load also avoids paying for the associated energy. PRD meets its obligation by responding when LMP is at or above price thresholds defined in the PRD plan.[61] PRD does not have to respond during performance assessment intervals (PAI) and therefore is inferior to other capacity resources and is not a substitute for other capacity resources in the capacity performance construct. The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and cleared for the 2021/2022 Delivery Year and 2022/2023 Delivery Year.[62]

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 6-15 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2020, through December 31, 2021. The ownership of economic

58 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).

59 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).

60 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

61 The Demand Response Subcommittee (DRS) is currently working to align PRD with the CP designed products.

62 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>.

demand response resources was highly concentrated in 2020 and 2021.[63] Table 6-15 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. In 2021, 70.1 percent of all economic DR reported reductions and 65.2 percent of economic DR revenue were attributable to the four largest CSPs. The HHI for economic demand response was highly concentrated for 2021. The annual HHI for economic demand response decreased by 539 from 9065 for 2020 to 8526 for 2021.

Table 6-15 Average hourly MWh HHI and market concentration in the economic program: January 2020 through December 2021[64]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2020	2021	Percent Change	2020	2021	Change in Percent	2020	2021	Change in Percent
Jan	8983	9305	3.6%	98.1%	99.3%	1.2%	98.3%	98.6%	0.3%
Feb	9652	7601	(21.3%)	100.0%	92.8%	(7.2%)	100.0%	90.5%	(9.5%)
Mar	9857	9700	(1.6%)	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
Apr	10000	9339	(6.6%)		100.0%			100.0%	
May	9926	9732	(2.0%)		100.0%			100.0%	
Jun	8976	8087	(9.9%)	100.0%	88.6%	(11.4%)	99.9%	83.6%	(16.3%)
Jul	8442	8238	(2.4%)	88.8%	91.5%	2.7%	90.2%	90.1%	(0.1%)
Aug	8344	8121	(2.7%)	93.5%	89.1%	(4.5%)	93.1%	90.1%	(3.0%)
Sep	8893	7940	(10.7%)	100.0%	95.3%	(4.7%)	100.0%	96.3%	(3.7%)
Oct	9400	8803	(6.4%)		96.9%			96.1%	
Nov	8121	8914	9.8%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
Dec	7745	9596	23.9%		100.0%			100.0%	
Total	9065	8526	(6.0%)	82.3%	70.1%	(12.2%)	82.8%	65.2%	(17.6%)

Market Performance

Table 6-16 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in 2010 through 2021. The average credits per MWh paid increased by $25.01 per MWh, 70.0 percent, from $35.72 per MWh in 2020 to $60.73 per MWh in 2021. The PJM real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh. Curtailed energy for the economic program increased by 9,527 MWh, 103.4 percent, from 9,213 MWh in 2020 to 18,740 MWh in 2021. Total credits paid for the economic load response program in 2021 increased by $0.8 million, 245.8 percent, from $0.3 million in 2020 to $1.1 million in 2021.

Table 6-16 Credits paid to economic program participants: 2010 through 2021

	Total MWh	Total Credits	$/MWh
2010	72,757	$3,088,049	$42.44
2011	17,398	$2,052,996	$118.00
2012	144,285	$9,278,942	$64.31
2013	133,963	$8,711,873	$65.03
2014	146,301	$17,820,063	$121.80
2015	121,129	$7,983,488	$65.91
2016	81,908	$3,550,535	$43.35
2017	62,622	$2,709,335	$43.27
2018	49,441	$2,548,575	$51.55
2019	24,306	$979,348	$40.29
2020	9,213	$329,119	$35.72
2021	18,740	$1,138,038	$60.73

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 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 December 31, 2021.

63 All HHI calculations in this section are at the parent company level.

64 April, May, October and December 2020 reduction and credit share values, and March and April 2021 reduction and credit share values are redacted based on confidentiality rules.

65 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 117 (Nov. 1, 2021).

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").

Figure 6-2 Economic program credits and MWh by month: 2010 through 2021

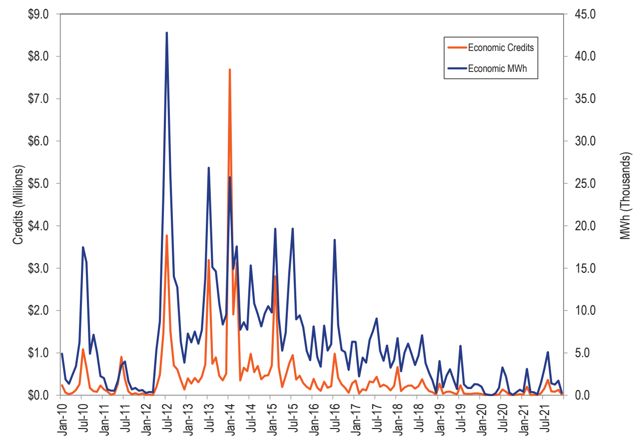


Table 6-17 shows performance for 2020 and 2021 in the economic program by control zone. Total reported reductions under the economic program increased by 8,344 MWh, 122.8 percent, from 6,796 MWh in 2020 to 15,140 MWh in 2021. Total revenue under the economic program increased by $0.7 million, 273.4 percent, from $0.3 million in2020 to $0.9 million in 2021.[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 6-17.

Table 6-17 Economic program participation by zone: 2020 and 2021

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2020	2021	Percent Change	2020	2021	Percent Change	2020	2021	Percent Change
ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$880.95	$378,207.22	42,831.7%	18	5,979	33,123.1%	$48.95	$63.26	29.2%
APS	$12,356.22	$13,965.80	13.0%	210	197	(6.3%)	$58.74	$70.88	20.7%
ATSI	$26,170.70	$29,286.94	11.9%	302	358	18.6%	$86.77	$81.85	(5.7%)
BGE	$0.00	$50,122.22	NA	0	641	NA	NA	$78.18	NA
COMED	$125,412.82	$32,908.38	(73.8%)	3,899	643	(83.5%)	$32.16	$51.16	59.0%
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$0.00	$232.58	NA	0	0	NA	NA	NA	NA
DOM	$2,226.86	$10,465.15	370.0%	46	80	71.8%	$48.10	$131.56	173.5%
DPL	$10,800.39	$28,300.73	162.0%	138	522	278.7%	$78.37	$54.23	(30.8%)
JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
MEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$27,814.61	$153,641.75	452.4%	589	2,655	350.5%	$47.20	$57.86	22.6%
PE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PEPCO	$97.49	$16,841.27	17,174.9%	2	297	18,305.1%	$60.39	$56.68	(6.1%)
PPL	$3,716.95	$130,792.33	3,418.8%	76	2,255	2,880.2%	$49.12	$58.00	18.1%
PSEG	$42,086.74	$94,578.87	124.7%	1,516	1,513	(0.2%)	$27.76	$62.52	125.2%
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$251,563.73	$939,343.24	273.4%	6,796	15,140	122.8%	$37.02	$62.05	67.6%

67 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-17. Payments for Economic demand response reductions are settled monthly.

68 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 85 (Sep. 1, 2021).

Table 6-18 shows average reported MWh reductions and credits by hour for 2020 and 2021. 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 2020, 97.2 percent of the reported reductions and 96.5 percent of credits occurred in hours ending 0900 to 2100, and in 2021, 89.1 percent of the reported reductions and 89.7 percent of credits occurred in hours ending 0900 to 2100.

Table 6-18 Hourly frequency distribution of economic program reported MWh reductions and credits: 2020 and 2021

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2020	2021	Percent Change	2020	2021	Percent Change	2020	2021	Percent Change
1 through 6	7	472	6,985%	$264	$26,363	9,885%	$37.30	$62.05	66%
7	30	281	825%	$1,360	$18,327	1,248%	$40.03	$76.25	90%
8	141	372	164%	$5,996	$24,092	302%	$41.52	$87.98	112%
9	212	604	185%	$6,756	$32,847	386%	$29.85	$63.93	114%
10	242	635	162%	$7,195	$31,153	333%	$27.49	$54.35	98%
11	258	699	171%	$6,895	$33,315	383%	$27.86	$54.14	94%
12	555	823	48%	$15,191	$39,936	163%	$27.68	$52.75	91%
13	764	931	22%	$21,137	$47,189	123%	$29.83	$55.76	87%
14	907	1,321	46%	$29,694	$77,558	161%	$33.51	$62.58	87%
15	1,084	1,462	35%	$36,260	$86,863	140%	$37.03	$63.05	70%
16	1,101	1,748	59%	$38,897	$120,773	210%	$38.37	$68.25	78%
17	1,251	2,112	69%	$51,157	$153,604	200%	$43.03	$77.13	79%
18	1,226	2,614	113%	$56,196	$165,633	195%	$43.50	$82.22	89%
19	969	1,598	65%	$36,483	$111,456	206%	$36.19	$74.40	106%
20	258	1,237	380%	$7,610	$70,336	824%	$28.32	$63.26	123%
21	127	910	617%	$4,013	$50,006	1,146%	$27.75	$58.50	111%
22	52	546	943%	$2,818	$28,672	917%	$29.24	$55.87	91%
23 through 24	29	376	1,184%	$1,197	$19,912	1,563%	$24.62	$105.70	329%
Total	9,213	18,740	103%	$329,119	$1,138,038	246%	$33.51	$67.68	106%

Table 6-19 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in 2020 and 2021. In 2021, 1.8 percent of reported MWh reductions and 2.5 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-19 Frequency distribution of economic program zonal load-weighted average LMP (By hours): 2020 and 2021

	MWh Reductions			Program Credits		
LMP	2020	2021	Percent Change	2020	2021	Percent Change
$0 to $25	3,697	980	(73%)	$96,190	$27,120	(72%)
$25 to $50	4,193	8,158	95%	$153,988	$390,466	154%
$50 to $75	759	5,532	628%	$34,543	$354,493	926%
$75 to $100	189	1,817	863%	$5,567	$150,693	2,607%
$100 to $125	168	1,375	718%	$10,447	$144,507	1,283%
$125 to $150	68	342	404%	$8,792	$31,725	261%
$150 to $175	46	207	353%	$3,368	$10,850	222%
> $175	93	329	253%	$16,223	$28,184	74%
Total	9,213	18,740	103%	$329,119	$1,138,038	246%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-20 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. Real-time loads in AEP paid the highest Economic Load Response charges in 2021.

Table 6-20 Zonal Economic Load Response charge: 2021[69]

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
ACEC	$142	$2,082	$75	$28	$34	$1,005	$2,485	$5,616	$1,275	$1,012	$1,482	$135	$15,371
AEP	$2,443	$30,173	$1,562	$1,987	$683	$10,648	$22,654	$50,098	$13,673	$12,720	$21,112	$2,537	$170,291
APS	$980	$12,123	$672	$476	$262	$4,296	$8,892	$19,835	$5,158	$4,798	$8,386	$1,021	$66,899
ATSI	$1,214	$14,678	$878	$1,092	$357	$6,006	$12,324	$27,841	$7,274	$6,805	$10,546	$1,229	$90,243
BGE	$586	$7,600	$635	$494	$156	$3,011	$6,543	$14,407	$3,634	$3,131	$5,007	$635	$45,840
COMED	$1,578	$21,412	$829	$1,115	$484	$7,775	$18,880	$43,052	$10,981	$9,707	$12,662	$1,430	$129,905
DAY	$329	$4,140	$268	$348	$95	$1,563	$3,282	$7,299	$1,941	$1,797	$2,839	$344	$24,244
DUKE	$499	$6,349	$326	$427	$146	$2,479	$5,236	$11,694	$3,072	$2,761	$4,188	$511	$37,689
DUQ	$241	$2,937	$140	$212	$77	$1,301	$2,644	$5,880	$1,506	$1,392	$2,073	$240	$18,643
DOM	$2,135	$25,913	$1,612	$1,655	$554	$9,738	$21,178	$46,654	$12,336	$11,152	$17,836	$2,208	$152,971
DPL	$313	$4,634	$199	$584	$66	$1,714	$4,081	$8,788	$2,177	$1,828	$2,818	$314	$27,515
EKPC	$273	$3,854	$161	$190	$62	$1,091	$2,366	$5,440	$1,363	$1,249	$2,354	$269	$18,673
JCPLC	$298	$4,851	$186	$68	$104	$2,567	$5,467	$12,749	$2,798	$2,216	$3,457	$381	$35,141
MEC	$243	$3,719	$153	$151	$79	$1,403	$3,027	$6,910	$1,758	$1,553	$2,617	$322	$21,936
OVEC	$2	$28	$1	$2	$0	$7	$15	$34	$10	$11	$19	$2	$132
PECO	$606	$9,083	$315	$132	$144	$3,708	$8,245	$18,667	$4,605	$3,863	$5,770	$610	$55,747
PE	$333	$4,001	$197	$130	$90	$1,412	$2,906	$6,618	$1,752	$1,741	$2,885	$347	$22,411
PEPCO	$488	$6,970	$510	$405	$149	$2,779	$5,947	$12,870	$3,349	$2,936	$4,498	$565	$41,465
PPL	$658	$10,063	$335	$284	$200	$3,502	$7,524	$16,917	$4,345	$3,986	$6,947	$857	$55,618
PSEG	$785	$9,360	$425	$133	$198	$4,398	$9,295	$21,469	$5,176	$4,322	$6,604	$715	$62,879
REC	$25	$292	$14	$4	$8	$184	$356	$842	$183	$144	$215	$24	$2,291
Exports	$681	$18,547	$931	$2,184	$175	$3,832	$8,946	$18,386	$3,918	$3,941	$4,752	$918	$67,210
Total	$14,851	$202,811	$10,424	$12,098	$4,122	$74,417	$162,294	$362,067	$92,286	$83,066	$129,066	$15,612	$1,163,113

Table 6-21 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in 2021.

Table 6-21 Zonal economic load response charge per GWh of load and exports: 2021

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.178	$2.826	$0.110	$1.365	$0.048	$1.073	$2.127	$4.824	$1.452	$1.403	$2.114	$0.176	$1.556
AEP	$0.211	$2.800	$0.156	$1.320	$0.072	$1.010	$2.004	$4.284	$1.384	$1.354	$2.105	$0.242	$1.471
APS	$0.212	$2.837	$0.170	$1.348	$0.072	$1.073	$2.071	$4.469	$1.403	$1.353	$2.129	$0.245	$1.517
ATSI	$0.216	$2.768	$0.172	$1.332	$0.072	$1.052	$2.037	$4.375	$1.392	$1.352	$2.082	$0.229	$1.491
BGE	$0.208	$2.907	$0.271	$1.406	$0.071	$1.109	$2.106	$4.653	$1.468	$1.421	$2.163	$0.253	$1.578
COMED	$0.201	$2.814	$0.118	$1.291	$0.070	$0.894	$2.059	$4.378	$1.411	$1.375	$1.810	$0.191	$1.471
DAY	$0.216	$2.848	$0.203	$1.364	$0.074	$1.067	$2.071	$4.418	$1.436	$1.382	$2.114	$0.248	$1.522
DUKE	$0.216	$2.883	$0.164	$1.357	$0.073	$1.054	$2.051	$4.434	$1.427	$1.397	$2.110	$0.244	$1.518
DUQ	$0.216	$2.839	$0.141	$1.352	$0.075	$1.101	$2.067	$4.435	$1.425	$1.390	$2.078	$0.227	$1.517
DOM	$0.220	$2.887	$0.198	$1.362	$0.070	$1.052	$2.032	$4.462	$1.417	$1.400	$2.127	$0.249	$1.522
DPL	$0.183	$2.903	$0.142	$1.395	$0.050	$1.054	$2.120	$4.690	$1.463	$1.422	$2.028	$0.208	$1.555
EKPC	$0.200	$2.952	$0.158	$1.390	$0.069	$1.096	$2.088	$4.673	$1.426	$1.361	$2.184	$0.264	$1.561
JCPLC	$0.159	$2.807	$0.115	$1.431	$0.065	$1.215	$2.258	$5.216	$1.505	$1.404	$2.166	$0.216	$1.641
MEC	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
OVEC	$0.194	$2.667	$0.131	$1.168	$0.058	$0.823	$1.682	$3.669	$1.197	$1.221	$1.988	$0.217	$1.288
PECO	$0.178	$2.875	$0.105	$1.345	$0.051	$1.066	$2.081	$4.723	$1.449	$1.379	$1.994	$0.194	$1.541
PE	$0.217	$2.825	$0.140	$1.311	$0.071	$1.019	$1.994	$4.333	$1.354	$1.327	$2.103	$0.242	$1.474
PEPCO	$0.194	$2.955	$0.242	$1.391	$0.073	$1.108	$2.080	$4.528	$1.454	$1.433	$2.152	$0.253	$1.558
PPL	$0.171	$2.853	$0.099	$1.336	$0.067	$1.041	$2.053	$4.524	$1.406	$1.351	$2.126	$0.244	$1.506
PSEG	$0.221	$2.854	$0.134	$1.368	$0.064	$1.109	$2.092	$4.757	$1.436	$1.369	$2.123	$0.211	$1.559
REC	$0.223	$2.854	$0.138	$1.456	$0.075	$1.273	$2.304	$5.324	$1.499	$1.387	$2.128	$0.222	$1.683
Exports	$0.216	$3.660	$0.280	$1.353	$0.063	$0.875	$1.951	$4.169	$1.104	$1.209	$1.802	$0.180	$1.519
Monthly Average	$0.193	$2.755	$0.154	$1.293	$0.064	$1.008	$1.969	$4.334	$1.341	$1.304	$1.983	$0.216	$1.457

69 Load response charges were downloaded March 4, 2022 and may change as a result of continued PJM billing updates.

Table 6-22 shows the monthly day-ahead and real-time Economic Load Response charges for 2020 and 2021. The day-ahead Economic Load Response charges increased by $552.8 thousand, 219.0 percent, from $252.4 thousand in 2020 to $805.2 thousand in2021. The real-time Economic Load Response charges increased $256.1 thousand, 333.9 percent, from $76.7 thousand in 2020 to $332.8 thousand in 2021.

Table 6-22 Monthly day-ahead and real-time economic load response charge: 2020 through 2021

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2020	2021	Percent Change	2020	2021	Percent Change
Jan	$28,908	$14,204	(50.9%)	$1,391	$648	(53.5%)
Feb	$2,317	$160,337	6,821.1%	$335	$42,474	12,591.2%
Mar	$936	$10,287	999.3%	$237	$136	(42.6%)
Apr	$0	$8,332	NA	$197	$3,766	1,814.3%
May	$4,315	$2,060	(52.3%)	$1,846	$2,062	11.7%
Jun	$11,138	$37,802	239.4%	$5,458	$11,412	109.1%
Jul	$87,384	$120,863	38.3%	$49,176	$41,559	(15.5%)
Aug	$70,100	$178,881	155.2%	$14,727	$183,186	1,143.9%
Sep	$10,140	$80,272	691.6%	$525	$12,014	2,188.3%
Oct	$1,694	$64,685	3,717.9%	$331	$18,381	5,457.1%
Nov	$10,064	$115,233	1,044.9%	$1,596	$13,833	766.6%
Dec	$25,410	$12,238	(51.8%)	$894	$3,373	277.5%
Total	$252,407	$805,194	219.0%	$76,712	$332,843	333.9%

Table 6-23 shows registered sites and MW for the last day of each month for the period January 1, 2015, through December 31, 2021. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations decreased by 7, 2.3 percent, from 316 in 2020 to 309 in 2021. Average monthly registered MW decreased by 114 MW, 5.6 percent, from 2,040 MW in 2020 to 1927 MW in 2021.

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 85 economic registrations and 92 capacity registrations in the emergency program that share the same location ids in both programs. There are 1,013 nominated economic MW and 796 nominated capacity MW in the emergency program that share the same location ids in both programs

Table 6-23 Economic program registrations on the last day of the month: 2015 through 2021[70]

	2015		2016		2017		2018		2019		2020		2021	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,078	2,960	838	2,557	871	2,603	537	2,570	374	2,651	377	2,909	277	1,495
Feb	1,076	2,956	835	2,557	842	2,578	537	2,628	370	2,640	382	2,912	275	1,503
Mar	1,075	2,949	834	2,556	850	2,576	519	2,641	378	2,648	380	2,941	284	1,514
Apr	1,076	2,938	832	2,556	897	2,574	501	2,624	366	2,594	350	2,917	293	1,538
May	980	2,846	829	2,545	977	2,626	471	2,615	372	3,193	308	2,824	319	1,658
Jun	871	2,614	518	2,500	577	1,305	397	2,576	370	2,768	285	1,418	313	2,136
Jul	870	2,609	519	2,421	589	1,548	374	2,591	376	2,899	283	1,453	312	2,105
Aug	869	2,609	805	2,569	590	1,541	382	2,609	360	2,885	292	1,482	322	2,122
Sep	867	2,608	831	2,608	588	1,663	378	2,580	368	2,954	297	1,566	322	2,256
Oct	858	2,568	822	2,564	574	1,660	382	2,584	375	2,909	275	1,361	332	2,267
Nov	851	2,566	820	2,564	559	1,662	381	2,581	379	3,051	280	1,375	333	2,270
Dec	850	2,566	807	2,561	556	1,659	392	2,671	383	3,070	282	1,327	320	2,256
Avg	974	2,788	774	2,547	706	2,000	438	2,606	373	2,855	316	2,040	309	1,927

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 6-24 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through December 31, 2021. The monthly peak is the sum of each registration's monthly noncoincident peak dispatched MW and annual peak is the sum of each registration's annual noncoincident peak

70 Data for years 2010 through 2014 are available in the *2018 State of the Market Report for PJM.*

dispatched MW. The peak dispatched MW for all economic demand response registered resources increased by 724.9 MW, 370.1 percent, from 195.9 MW 2020 to 920.8 MW in 2021.[71] The largest monthly peak MW reduction in 2021, 827 MW in August, was 1,100 MW less than the average MW registered in 2021, 1,927 MW.

Table 6-24 Sum of peak MW reported reductions for all registrations per month: 2010 through 2021

	Sum of Peak MW Reductions for all Registrations per Month											
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan	183	132	110	193	446	169	139	123	142	88	28	21
Feb	121	89	101	119	307	336	128	83	70	58	11	86
Mar	115	81	72	127	369	198	120	111	71	38	12	20
Apr	111	80	108	133	146	143	118	54	71	41	3	22
May	172	98	143	192	151	161	131	169	70	22	12	9
Jun	209	561	954	433	483	833	121	240	105	26	38	125
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	770	135	134
Aug	794	161	952	497	358	272	249	141	581	33	99	827
Sep	276	84	451	530	795	816	263	140	112	76	31	35
Oct	118	81	242	168	214	136	150	88	69	29	9	31
Nov	111	86	165	155	166	127	116	81	54	35	12	31
Dec	114	88	98	168	155	122	147	83	11	31	14	19
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196	921

Table 6-25 shows total settlements submitted for 2010 through 2021. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-25 Settlements submitted in the economic program: 2010 through 2021

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Number of Settlements	3,781	732	5,835	2,846	3,014	2,173	1,958	1,884	1,524	1,066	520	931

Table 6-26 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for 2010 through 2021. The number of active participants increased by 8, 27.6 percent, from 29 in 2020 to 37 in 2021. All participants must be registered through a CSP.

Table 6-26 Participants and CSPs submitting settlements in the economic program by year: 2010 through 2021

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Active CSPs	16	15	22	20	18	18	12	13	14	13	11	11
Active Participants	258	203	428	276	165	116	58	72	59	53	29	37

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[72] 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."[73] 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

71 Peak MW reductions were downloaded on March 4, 2022 and may change as a result of continued PJM billing updates.
72 157 FERC ¶ 61,115 at P 139 (2016).
73 *Id.* at 8.

rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load. PJM calculates the NBT price threshold by first taking the generation offers from the same month of the previous year. For example, the NBT price calculation for February 2017 was calculated using generation offers from February 2016. PJM then adjusts these offers to account for changes in fuel prices and uses these adjusted offers to create an average monthly supply curve. PJM estimates a function that best fits this supply curve and then finds the point on this curve where the elasticity is equal to one.[74] The price at this point is the NBT threshold price.

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 reported reductions.

Table 6-27 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when FERC Order No. 745 was implemented in PJM, through December 2021. The historical test was used as justification for the method of calculating the NBT for future months. The NBT threshold price has exceeded the lowest historical test result of $34.07 per MWh one time, in March 2014 when the NBT threshold price was $34.93.

Table 6-27 Net benefits test threshold prices: August 2010 through December 2021

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)									
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82
Apr		$36.76	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01	$14.69	$21.40
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.64	$16.87	$23.03

Table 6-28 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. In 2021, the highest zonal LMP in PJM was higher than the NBT threshold price 8,218 hours out of 8,760 hours, or 93.8 percent of all hours. Reductions occurred in 3,032 hours, 36.9 percent, of those 8,218 hours in 2021. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2020, through December 31, 2021. There are no economic

74 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 117 (Nov. 1, 2021).

payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reported reductions occurred in none of the hours in which LMP was below the NBT threshold price in 2021, and 0.1 percent (1 hour) of the hours in which LMP was below the NBT threshold price in 2020.

Table 6-28 Hours with price higher than NBT and economic load response occurrences in those hours: 2020 through 2021

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2020	2021	2020	2021	Percent Change	2020	2021	Percentage Change
Jan	744	744	569	741	30.2%	38.1%	11.9%	(26.3%)
Feb	696	672	513	667	30.0%	15.0%	50.2%	35.2%
Mar	743	743	558	698	25.1%	9.0%	12.5%	3.5%
Apr	720	720	606	618	2.0%	2.0%	21.4%	19.4%
May	744	744	635	636	0.2%	19.5%	24.4%	4.8%
Jun	720	720	495	592	19.6%	36.4%	44.9%	8.6%
Jul	744	744	675	727	7.7%	50.1%	49.1%	(1.0%)
Aug	744	744	695	744	7.1%	24.9%	54.7%	29.8%
Sep	720	720	648	720	11.1%	7.4%	43.2%	35.8%
Oct	744	744	676	744	10.1%	3.3%	48.5%	45.3%
Nov	721	721	607	721	18.8%	14.2%	52.6%	38.4%
Dec	744	744	712	610	(14.3%)	18.7%	25.2%	6.6%
Total	8,784	8,760	7,389	8,218	11.2%	19.8%	36.9%	17.1%

Energy Efficiency

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not produce power, but reduce power consumption. The Nominated MW for EE resources are not measured, although they could be, but a calculated value based on a set of largely unverified and unverifiable assumptions. An installed EE resource may participate as a capacity resource for up to four consecutive delivery years.[75]

Prescriptive energy efficiency MW have an assumed savings calculated based on an assumed installation rate and the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM capacity market is prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement or verification but instead relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.[76] There is no evidence that the programs result in changed behavior or increases in savings.

The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market. The measurement and verification protocols for energy efficiency are too imprecise to rely on as a source of capacity. Effective energy efficiency measures reduce energy usage and capacity usage directly. The reduced market payments are the appropriate compensation.

Energy efficiency resources are included in the PJM Capacity Market. Table 6-29 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.[77] Only Kentucky has been authorized by the Commission.[78] The total MW of energy efficiency resources committed increased by 0.1 percent from 4,806.2 MW in the 2021/2022 Delivery Year to 4,810.6 MW in the 2022/2023 Delivery Year.[79]

75 PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 51 (Oct. 20, 2021).

76 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 04 (August 22, 2019).

77 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

78 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).

79 See the *2021 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

Table 6-29 Energy efficiency resources (MW): Delivery Years 2011/2012 through 2022/2023

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE Percent Cleared
2011/2012	76.4	134,139.6	0.1%
2012/2013	666.1	141,061.8	0.5%
2013/2014	904.2	159,830.5	0.6%
2014/2015	1,077.7	161,092.4	0.7%
2015/2016	1,189.6	173,487.4	0.7%
2016/2017	1,723.2	179,749.0	1.0%
2017/2018	1,922.3	180,590.3	1.1%
2018/2019	2,296.3	175,957.4	1.3%
2019/2020	2,528.5	177,040.6	1.4%
2020/2021	3,569.5	173,688.5	2.1%
2021/2022	4,806.2	174,713.0	2.8%
2022/2023	4,810.6	144,477.3	3.3%

Distributed Energy Resources

Distributed Energy Resources (DER) are not well defined, but generally include small scale generation directly connected to the grid, generation connected to distribution level facilities and behind the meter generation.[80] For example, Table 6-10 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2019/2020 Delivery Year. Clear rules for defining DERs and for defining the ways in which DERs will interact with the wholesale power markets do not yet exist, although the development of those rules is under active discussion.[81] [82] DERs should be treated like other resources. Creating preferential treatment for DERs could create an incentive to move resources behind the meter in a manner inconsistent with efficiency and competitive markets. FERC directed that DER aggregation be as geographically broad as technically feasible.[83]

The current demand response rules appropriately restrict demand response from injecting power into the grid and receiving demand response revenue. At the January 30, 2019, Demand Response Subcommittee meeting, PJM, without a stakeholder process or FERC approval, decided to allow some economic load response payments when economic load response resources injects power into the grid. PJM's test compares the total benefits of running the generator which includes generation payments and assumed retail rate savings against the total cost of the generator. If the total cost of the generator is greater than the benefits, then the resource would receive economic load response payments while injecting. The use of a retail rate in calculating wholesale power market benefits raises significant issues analogous to net metering that require discussion and tariff changes. PJM should not include retail rate benefits in the definition of demand response without approval of FERC.

Aggregation to a single node is technically feasible. Allowing DER aggregation across nodes is not necessary and is not consistent with the nodal market design. 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.

FERC issued Order No. 2222 on September 17, 2020, requiring RTOs and ISOs to revise their tariffs to accommodate participation of distributed energy resources (DERs) in the wholesale market.[84] FERC Order No. 2222 defined DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter" and included demand response resources in the definition. The goal of FERC Order No. 2222 is to remove barriers for small distributed resources to enter the wholesale market by allowing them to aggregate and relaxing some qualification and performance requirements. The order states that removing barriers would encourage competition which can increase the efficiency of the RTO markets and reduce the risk of over procurement by including DERs in RTOs' planning.[85] PJM made a compliance filing at FERC on February 1, 2022.

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 fact that DERs' impact on the transmission system is currently negligible should not be an excuse to create inefficient rules. An increase in DERs will change flows

80 Some energy storage facilities may be DERs. FERC Order No. 841 requires that energy storage resources have access to capacity, energy and ancillary service markets. *See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 at P 1 (2018).

81 In PJM, the Distributed Energy Resources Subcommittee (DERSC) is currently discussing these issues. *Distributed Energy Resources Subcommittee*, PJM, <http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx>.

82 See "Notice of Technical Conference," Docket No. RM18-9-000 and AD18-10-000 (February 15, 2018); "Technical Conference Distributed Energy Resources," Docket No. RM18-9-000 and AD18-10-000 (April 10, 2018).

83 162 FERC ¶ 32,718 at P 139 (2016).

84 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020).

85 Id. PP 6-7.

on the power grid. No rules, jurisdictional issues or the lack of a transmission interconnection process should prevent PJM from acquiring all necessary information to protect the reliability and the efficiency of the wholesale power markets.

The new DER market rules should not threaten the nodal market principle or the reliability of the transmission system. Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed. PJM proposed a single node aggregation, which is consistent with nodal market design. But the accuracy of the selection of the primary node, especially in real time, is not guaranteed. PJM's proposal does not include regular updates to the primary node information that is provided during the registration process. PJM should have accurate information about a resource's location and to have the ability to update the information as needed for system reliability and correct nodal pricing.

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 proposed design would give EDCs market power. EDCs can also control competitors' access to sensitive market data including meter data. For example, EDCs have an inherent advantage over their competitors due to their knowledge of the best potential locations on their distribution system for DERs. EDCs already have metering equipment in place for retail use while competitors will need to install new equipment. EDCs can recover the cost of deploying any necessary metering devices through cost of service ratemaking, which guarantees return on investment, while competitors face market risks. This dual role would give EDCs market power. The result will be uncompetitive wholesale market rates. The role of the EDCs as it affects the wholesale power market is within FERC's authority to ensure just and reasonable wholesale rates. The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

The same standards should apply to DER Aggregation Resources as apply to all other resources in the PJM markets. Under the proposed DER rules, favorable treatment of resources that participate in the DER aggregation model over other market participants includes: exemption from the PJM interconnection process; no must offer requirement in the capacity market; exemption from the RPM Minimum Offer Price Rule (MOPR); exemption from the market seller offer cap 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 for DER Aggregation Resources to avoid the obligations of market participation. PJM proposed the maximum size requirement of 5 MW for component DERs but did not propose a maximum size requirement for DER Aggregation Resources.[86] This loophole would allow large DERs to divide one large resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource. The goal of FERC Order No. 2222 is to remove barriers for small distributed resources. To avoid this loophole, there should be a maximum size requirement on the DER Aggregation Resource. The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations.

Energy injections from resources that also reduce load should be treated the same as any energy injection from other resource types. PJM has not proposed tariff language changes regarding demand response resources with energy injection capability. Rules for demand response resources and rules for generation resources are different and often conflicting. Resources that can both curtail load and inject energy require a distinct set of rules to ensure that they are not compensated for capacity and energy beyond their actual capability. For example, the tariff should clearly define how the customer baseline ("CBL") is calculated for demand response resources with injection capability.

86 Individual DERs in DER Aggregation Resources. See definitions in the PJM compliance filing.