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.

  In the first nine months of 2019, total demand response revenue decreased by $41.5 million, 9.5 percent, from $435.1 million in the first nine months of 2018 to $393.7 million in the first nine months of 2019. Emergency demand response revenue accounted for 98.8 percent of all demand response revenue, economic demand response for 0.2 percent, demand response in the Synchronized Reserve Market for 0.3 percent and demand response in the regulation market for 0.3 percent.

  Total emergency demand response revenue decreased by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. This decreased consisted entirely of capacity market revenue.[2]

  Economic demand response revenue decreased by $1.5 million, 65.3 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[3] Demand response revenue in the Synchronized Reserve Market decreased by $2.1 million, 50.1 percent, from $4.2 million in the first nine months of 2018 to $2.1 million in the first nine months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 20.9 percent, from $2.3 million in the first nine months of 2018 to $1.8 million in the first nine months of 2019.

- **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 demand response resources was highly concentrated in 2018 and the first nine months of 2019. The HHI for economic resource reductions increased by 535 points from 7541 in the first nine months 2018 to 8076 in the first nine months of 2019. The ownership of emergency demand response resources was moderately concentrated in the first nine months of 2019. The HHI for emergency demand response committed MW was 1808 for the 2018/2019 Delivery Year and 1838 for the 2019/2020 Delivery Year. In the 2018/2019 Delivery Year, the four largest companies owned 78.1 percent of all committed demand response UCAP MW. In the 2019/2020 Delivery Year, the four largest companies owned 78.8 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources that are not Capacity Performance, are dispatchable for mandatory reductions on a subzonal basis, defined by zip codes, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. Nodal dispatch of demand resources in a nodal market would

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

2 The total credits and MWh numbers for demand resources were calculated as of October 15, 2019 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. 82 (July 25, 2019).

improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources. With full implementation of the Capacity Performance rules in the capacity market starting with the 2020/2021 Delivery Year, PJM will be able to individually dispatch demand resources with no advanced notice, although PJM does not know the nodal location of demand resources.

Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to demand response in the Capacity Performance filing. The status of each recommendation reflects the status at September 30, 2019.

- 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. (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.)

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

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

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

- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with 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 Q2, 2019. Status: Not adopted.)

7 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

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. The Capacity Performance demand response product definition in the PJM Capacity Performance capacity market design is a significant step in that direction, although performance obligations are still not identical to other capacity resources. 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 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 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, 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 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 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 M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement

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 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 for the next three years. 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. 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). Under current rules, there is no functional difference between pre-emergency and emergency demand resources. Table 6-1 provides an overview of the key features of PJM demand response programs.

The current PRD rules do not align with the definition of capacity under the Capacity Performance construct despite PJM's attempt to create alignment.[12] The PJM proposed rule changes do not require reductions during PAI unless LMP is above the specified price threshold. PJM incorrectly values PRD capacity and measured performance.[13] Similar to emergency and pre-emergency demand response, PJM would limit the nominated MW for PRD resources to the lower of the Peak Load Contribution (PLC) minus the Firm Service Level (FSL) times the loss factor (LF) or the Winter Peak Load (WPL) multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) minus the winter Firm Service Level (wFSL) times the loss factor for each zone.

$$PRD\ Value = Min\{(PLC - FSL * LF), (WPL * ZWWAF - wFSL)\} * zonal\ loss\ factor$$

Use of the WPL would artificially limit the amount of MW that can participate as PRD if the WPL is less than the PLC. The Commission rejected PJM's filing regarding PRD on June 27, 2019 for these reasons.[14]

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.[15] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the regulation market.

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.[16] 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. 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.

12 See "Proposed Amendments to Price Response Demand Rules," Docket No. ER19-1012- (February 7, 2019).
13 See "Comments of the Independent Market Monitor for PJM," Docket No. ER19-1012 (February 28, 2019).
14 See 167 FERC ¶ 61,268 (June 27, 2019).
15 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.
16 OA Schedule 1 § 8.5.

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.[17] 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.[18]

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)				
Market	Capacity Only	Capacity and Energy	Energy Only	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
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA	RPM event or test compliance penalties
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	Avoided capacity costs
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.	NA

Participation in Demand Response Programs

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

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.[19] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits an end use customers' participation.[20] 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

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.

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

18 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>.

19 *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).

20 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.

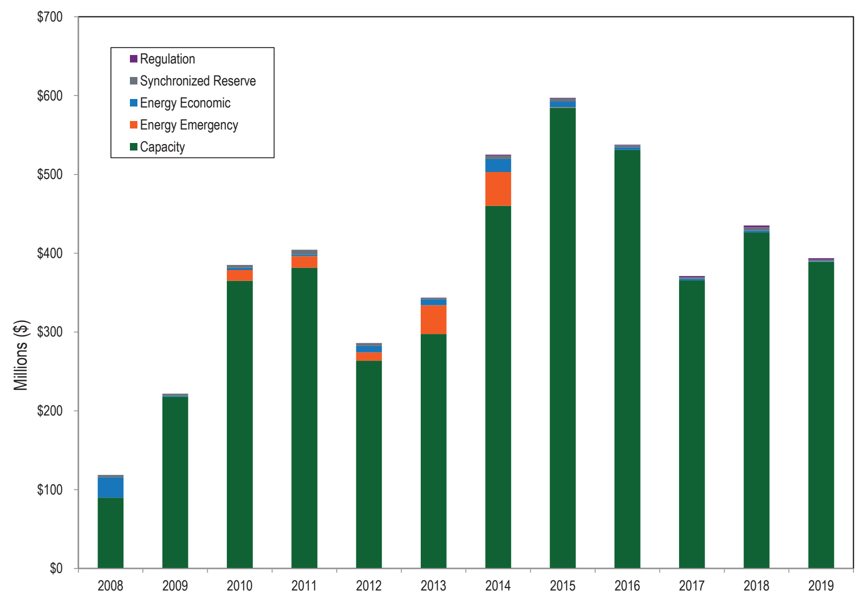
provide additional verification.[21] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program. There are 188 active RERRAs within PJM.

Figure 6-1 shows all revenue from PJM demand response programs by market for the first nine months of 2008 through 2019. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[22] In the first nine months of 2019, total demand response revenue decreased by $41.5 million, 9.5 percent, from $435.1 million in the first nine months of 2018 to $393.7 million in the first nine months of 2019. Total emergency demand response revenue decreased by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. This decrease consisted entirely of capacity market revenue.[23] In the first nine months of 2019, demand resource revenue, which includes capacity and emergency energy revenue, accounted for 98.8 percent of all revenue received by demand response providers, the economic program for 0.2 percent, synchronized reserve for 0.5 percent and the regulation market for 0.5 percent.

Economic demand response revenue decreased by $1.5 million, 65.3 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[24] Demand response revenue in the Synchronized Reserve Market decreased by $2.1 million, 50.1 percent, from $4.2 million in the first nine months of 2018 to $2.1 million in the first nine months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 20.9 percent, from $2.3 million in the first nine months of 2018 to $1.8 million in the first nine months of 2019.

Lower demand resource revenues were in part a result of lower capacity market prices in the 2019/2020 RPM auction. The capacity revenue in 2018 is from 2017/2018 RPM and 2018/2019 RPM auction clearing prices and the capacity revenue in 2019 is from 2018/2019 RPM and 2019/2020 RPM auction clearing prices. The annual RTO capacity market prices decreased $64.77 per MW-day from $164.77 in the 2018/2019 Delivery Year to $100.00 in the 2019/2020 Delivery Year, a 39.3 percent increase.

Figure 6-1 Demand response revenue by market: January through September, 2008 through 2019



Economic Program

FERC Order No. 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[25] 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."[26] Demand resources participate in both the

21 PJM Operating Agreement Schedule 1 § 1.5A.3.1.
22 This includes both capacity market revenue and emergency energy revenue for capacity resources.
23 The total credits and MWh for demand resources were calculated as of October 15, 2019 and may change as a result of continued PJM billing updates. There was no emergency energy revenue in the first nine months of 2019.
24 Economic credits are synonymous with revenue received for reductions under the economic load response program.
25 157 FERC ¶ 61,115 (2016).
26 *Id.* at 8.

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 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.

Table 6-2 shows registered sites and MW for the last day of each month for the period January 1, 2015, through September 30, 2019. Registration is a prerequisite for CSPs to participate in the economic program. The monthly average number of registrations for economic demand response decreased and the monthly average registered MW increased in the first nine months of 2019 compared to the first nine months of 2018. Average monthly registrations decreased by 83, 18.3 percent, from 455 in the first nine months of 2018 to 372 in the first nine months of 2019. Average monthly registered MW increased by 218 MW, 8.4 percent, from 2,604 MW in the first nine months of 2018 to 2,822 MW in the first nine months of 2019.

Table 6-2 Economic program registrations on the last day of the month: 2015 through 2019[27]

	2015		2016		2017		2018		2019	
Month	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	2,652
Feb	1,076	2,956	835	2,557	842	2,578	537	2,628	370	2,640
Mar	1,075	2,949	834	2,556	850	2,576	519	2,641	378	2,648
Apr	1,076	2,938	832	2,556	897	2,574	501	2,624	366	2,595
May	980	2,846	829	2,545	977	2,626	471	2,615	372	3,193
Jun	871	2,614	518	2,500	577	1,305	397	2,576	370	2,769
Jul	870	2,609	519	2,421	589	1,548	374	2,591	376	2,900
Aug	869	2,609	805	2,569	590	1,541	382	2,609	361	2,888
Sep	867	2,608	831	2,608	588	1,663	378	2,580	378	3,112
Oct	858	2,568	822	2,564	574	1,660	382	2,584		
Nov	851	2,566	820	2,564	559	1,662	381	2,581		
Dec	850	2,566	807	2,561	556	1,659	392	2,671		
Avg	974	2,788	774	2,547	706	2,000	438	2,606	372	2,822

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 144 registrations and 991 nominated MW in the economic program, or 183 registrations and 573 nominated MW in the emergency program.

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 6-3 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through September 30, 2019. 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 dispatched MW. The peak dispatched MW for all economic demand response registered resources increased by 63 MW, 8.4 percent, from 755 MW in the first nine months of 2018 to 818 MW in the first nine months of 2019.[28] The peak dispatched MW in the first nine months of 2019, 770 MW, were 2,052 MW less than the average MW registered in the first nine months of 2019, 2,801 MW.

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

28 The total credits and MWh numbers for demand resources were calculated as of October 15, 2019 and may change as a result of continued PJM billing updates.

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through September 2019

	Sum of Peak MW Reductions for all Registrations per Month									
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan	183	132	110	193	446	169	139	123	142	88
Feb	121	89	101	119	307	336	128	83	70	58
Mar	115	81	72	127	369	198	120	111	71	38
Apr	111	80	108	133	146	143	118	54	71	41
May	172	98	143	192	151	161	131	169	70	22
Jun	209	561	954	433	483	833	121	240	105	26
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	770
Aug	794	161	952	497	358	272	249	141	581	28
Sep	276	84	451	530	795	816	263	140	112	8
Oct	118	81	242	168	214	136	150	88	69	
Nov	111	86	165	155	166	127	116	81	54	
Dec	114	88	98	168	155	122	147	83	11	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	818

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.[29] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions in the first nine months of 2010 through 2019. The average credits per MWh paid decreased by $11.05 per MWh, 20.9 percent, from $52.76 per MWh in the first nine months of 2018 to $41.71 per MWh in the first nine months of 2019. The PJM real-time load-weighted, average LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh. Curtailed energy for the economic program decreased by 25,207 MWh, 56.3 percent, from 44,735 MWh in the first nine months of 2018 to 19,528 MWh in the first nine months of 2019. Total credits paid for economic DR in the first nine months of 2018 decreased by $1.5 million, 65.5 percent, from $2.4 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.

Table 6-4 Credits paid to the PJM economic program participants: January through September, 2010 through 2019

(Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	121,381	$8,172,654	$67.33
2013	105,299	$7,387,658	$70.16
2014	118,007	$16,510,733	$139.91
2015	103,721	$7,355,263	$70.91
2016	67,516	$3,032,039	$44.91
2017	49,331	$2,167,590	$43.94
2018	44,735	$2,360,007	$52.76
2019	19,528	$814,484	$41.71

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.[30] 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.[31] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 1, 2010 through September 30, 2019.

29 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 82 (July 25, 2019).

30 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 107 (Sep. 26, 2019).

31 FERC Order No. 831.

Figure 6-2 Economic program credits and MWh by month: 2010 through September 2019

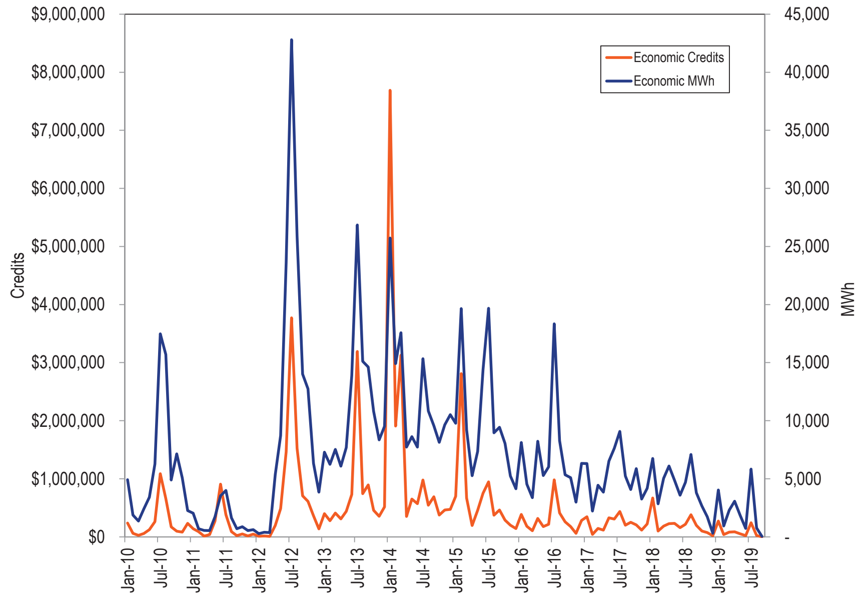


Table 6-5 shows performance for the first nine months of 2018 and 2019 in the economic program by control zone. Total reductions under the economic program decreased by 25,207 MWh, 56.3 percent, from 44,735 MW in the first nine months of 2018 to 19,528 MW in the first nine months of 2019. Total revenue under the economic program decreased by $1.5 million, 64.8 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[32]

32 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-5. Payments for Economic demand response reductions are settled monthly.

Table 6-5 PJM economic program participation by zone: January through September, 2018 and 2019

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
AECO	$0.00	$1,353.78	NA	115	41	(64.5%)	NA	$33.27	NA
AEP	$931.88	$3,848.34	313.0%	19	86	349.7%	$48.98	$44.98	(8.2%)
APS	$53,209.17	$70.19	(99.9%)	967	2	(99.8%)	$55.02	$42.15	(23.4%)
ATSI	$941,309.96	$9,355.23	(99.0%)	18,659	157	(99.2%)	$50.45	$59.71	18.4%
BGE	$152,018.22	$96,681.98	(36.4%)	2,692	2,352	(12.6%)	$56.47	$41.11	(27.2%)
ComEd	$172,215.00	$5,068.30	(97.1%)	4,685	176	(96.2%)	$36.76	$28.73	(21.8%)
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DEOK	$0.00	$2,922.39	NA	341	53	(84.4%)	NA	$55.16	NA
Dominion	$38,249.51	$267.33	(99.3%)	177	4	(97.9%)	$216.31	$71.78	(66.8%)
DPL	$0.00	$4,916.92	NA	(183)	150	(182.2%)	NA	$32.74	NA
DLCO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPL	$250,025.99	$16,793.13	(93.3%)	3,612	338	(90.6%)	$69.22	$49.66	(28.3%)
Met-Ed	$38,665.88	$29,103.14	(24.7%)	821	664	(19.2%)	$47.09	$43.86	(6.9%)
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$48,523.81	$125,165.86	157.9%	696	2,133	206.4%	$69.71	$58.68	(15.8%)
PENELEC	$122,502.06	$112,801.68	(7.9%)	4,000	3,464	(13.4%)	$30.62	$32.56	6.3%
Pepco	$0.00	$10,392.56	NA	(164)	313	(291.5%)	NA	$33.18	NA
PPL	$126,224.03	$143,383.61	13.6%	1,118	2,297	105.4%	$112.86	$62.43	(44.7%)
PSEG	$372,007.61	$252,359.64	(32.2%)	7,179	7,436	3.6%	$51.82	$33.94	(34.5%)
Total	$2,315,883.13	$814,484.08	(64.8%)	44,735	19,664	(56.0%)	$51.77	$41.42	(20.0%)

Table 6-6 shows total settlements submitted for the first nine months of 2010 through 2019. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted in the economic program: January through September, 2010 through 2019

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Settlements	3,367	703	5,334	2,358	2,425	1,851	1,524	1,417	1,263	875

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the first nine months of 2010 through 2019. The number of active participants decreased by seven, 12.1 percent, from 58 in the first nine months of 2018 to 51 in the first nine months of 2019. All participants must be registered through a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through September, 2010 through 2019

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Active CSPs	16	15	22	20	16	18	12	13	13	12
Active Participants	257	203	428	273	154	114	58	72	58	51

The ownership of economic demand response resources was highly concentrated in 2018 through September 2019.[33] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2018 through September 30, 2019. Table 6-8 also lists the share of reductions provided by, and the share of credits claimed by the four largest companies in each year. In the first nine months of 2019, 79.8 percent of all economic DR reductions and 72.3 percent of economic DR revenue were attributable to the four largest companies. The HHI for economic demand response increased by 535 from 7541 for the first nine months of 2018 to 8076 for the first nine months of 2019.

Table 6-8 Average hourly MWh HHI and market concentration in the economic program: January 2018 through September 2019[34]

	Average Hourly MWh HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2018	2019	Percent Change	2018	2019	Change in Percent	2018	2019	Change in Percent
Jan	6576	6884	4.7%	92.3%	82.1%	10.2%	88.6%	78.1%	10.5%
Feb	8304	9382	13.0%	99.2%	94.7%	4.5%	99.1%	90.7%	8.4%
Mar	7498	7758	3.5%	96.1%	99.3%	(3.3%)	95.7%	99.1%	(3.4%)
Apr	6828	7457	9.2%	97.3%	99.4%	(2.1%)	97.2%	99.8%	(2.6%)
May	6688	7875	17.8%	98.3%	99.9%	(1.6%)	97.9%	99.9%	(2.0%)
Jun	8375	9623	14.9%	97.4%	99.9%	(2.5%)	96.2%	99.9%	(3.7%)
Jul	8256	8035	(2.7%)	90.2%	88.8%	1.4%	90.3%	86.1%	4.2%
Aug	7588	9364	23.4%	90.0%	99.9%	(9.9%)	89.3%	99.9%	(10.6%)
Sep	9306	9890	6.3%	97.4%			96.9%		
Oct	6805			95.6%			93.9%		
Nov	7038			91.6%			91.8%		
Dec	8082								
Total	7541	8076	7.1%	84.9%	79.9%	(5.0%)	84.5%	72.3%	(12.2%)

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2018 and 2019. In the first nine months of 2018, 88.1 percent of reductions and 85.8 percent of credits occurred in hours ending 0900 to 2100, and in the first nine months of 2019, 89.2 percent of reductions and 85.5 percent of credits occurred in hours ending 0900 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January through September, 2018 and 2019

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
1 through 6	1,270	522	(59%)	$92,768	$31,808	(66%)
7	1,031	264	(74%)	$65,777	$17,158	(74%)
8	1,683	471	(72%)	$97,804	$29,217	(70%)
9	2,114	786	(63%)	$101,228	$32,979	(67%)
10	2,341	908	(61%)	$103,253	$33,546	(68%)
11	2,485	1,004	(60%)	$112,382	$38,085	(66%)
12	2,668	1,048	(61%)	$117,939	$33,185	(72%)
13	2,621	1,094	(58%)	$125,559	$37,501	(70%)
14	3,397	1,431	(58%)	$155,813	$50,468	(68%)
15	3,464	1,479	(57%)	$173,739	$51,749	(70%)
16	3,588	1,672	(53%)	$193,752	$59,574	(69%)
17	4,272	1,985	(54%)	$235,971	$77,238	(67%)
18	4,078	1,996	(51%)	$220,545	$102,582	(53%)
19	3,080	1,706	(45%)	$173,300	$73,861	(57%)
20	2,863	1,264	(56%)	$145,088	$52,278	(64%)
21	2,437	1,186	(51%)	$127,545	$53,341	(58%)
22	862	537	(38%)	$46,977	$24,961	(47%)
23 through 24	482	309	(36%)	$26,446	$14,954	(43%)
Total	44,735	19,664	(56%)	$2,315,883	$814,484	(65%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first nine months of 2018 and 2019. In the first nine months of 2019, 1.0 percent of MWh reductions and 3.9 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

33 All HHI calculations in this section are at the parent company level. Parent companies may own one CSP or multiple CSPs.
34 December 2018 and September 2019 reduction and credit share percent are redacted based on confidentiality rules.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through September, 2018 and 2019

	MWh Reductions			Program Credits		
LMP	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
$0 to $25	3,876	4,282	10%	$69,164	$107,730	56%
$25 to $50	26,579	11,758	(56%)	$971,020	$431,293	(56%)
$50 to $75	6,238	2,052	(67%)	$360,293	$125,601	(65%)
$75 to $100	3,376	722	(79%)	$269,879	$55,223	(80%)
$100 to $125	1,449	394	(73%)	$142,668	$36,529	(74%)
$125 to $150	1,077	136	(87%)	$120,499	$11,657	(90%)
$150 to $175	563	124	(78%)	$69,726	$14,682	(79%)
> $175	1,578	196	(88%)	$312,632	$31,768	(90%)
Total	44,735	19,664	(56%)	$2,315,883	$814,484	(65%)

Following 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.[35] 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 reductions.

Table 6-11 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when Order No. 745 was implemented in PJM, through September 2019. The NBT threshold price has never exceeded the lowest historical test result of $34.07 per MWh.

Table 6-11 Net benefits test threshold prices: August 2010 through September 2019

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)							
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15
Apr		$36.76	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.80

Table 6-12 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 the first nine months of 2019, the highest zonal LMP in PJM was higher than the NBT threshold price 5,630 hours out of 6,551 hours, or 85.9 percent of all hours. Reductions occurred in 1,949 hours, 34.6 percent, of those 5,630 hours in the first nine months of 2019. The last three columns illustrate how often

35 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 107 (Sep. 26, 2019).

economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2018 through October 31, 2019. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reductions occurred in 0.05 percent (1 hour) of the hours in which LMP was below the NBT threshold price in the first nine months of 2019, and none of the hours in which LMP was below the NBT threshold price in 2018.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2018 through September 2019

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2018	2019	2018	2019	Percent Change	2018	2019	Percent Change
Jan	744	744	665	503	(24.4%)	62.9%	51.9%	(11.0%)
Feb	672	672	485	582	20.0%	44.7%	22.9%	(21.9%)
Mar	743	743	713	711	(0.3%)	58.3%	40.5%	(17.8%)
Apr	720	720	663	559	(15.7%)	73.8%	55.1%	(18.7%)
May	744	744	611	579	(5.2%)	62.7%	45.1%	(17.6%)
Jun	720	720	503	488	(3.0%)	64.0%	25.2%	(38.8%)
Jul	744	744	549	744	35.5%	74.0%	46.9%	(27.0%)
Aug	744	744	560	744	32.9%	72.5%	28.6%	(43.9%)
Sep	720	720	643	720	12.0%	64.2%	1.8%	(62.4%)
Oct	744		699			50.9%		
Nov	721		702			43.9%		
Dec	744		627			12.1%		
Total	8,760	6,551	7,420	5,630	(24.1%)	56.7%	34.6%	(22.1%)

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges paid in each zone and paid by exports. Real-time loads in AEP paid the highest DR charges in the first nine months of 2019.

Table 6-13 Zonal DR charge: January through September, 2019

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$3,107	$402	$813	$712	$370	$251	$3,794	$304	$1	$5,655
AEP	$43,073	$6,115	$12,606	$14,331	$8,719	$3,283	$33,639	$3,595	$5	$88,128
APS	$18,269	$2,567	$5,104	$5,370	$3,330	$1,253	$12,897	$1,379	$2	$35,893
ATSI	$20,920	$3,150	$6,706	$7,709	$4,429	$1,672	$18,840	$1,934	$3	$44,587
BGE	$12,438	$1,635	$3,148	$3,355	$2,170	$924	$9,829	$976	$1	$23,670
ComEd	$18,936	$4,237	$8,395	$9,312	$5,596	$2,441	$30,921	$3,069	$3	$48,916
DAY	$6,000	$837	$1,776	$2,122	$1,188	$480	$4,974	$527	$1	$12,403
DEOK	$7,798	$1,224	$2,557	$2,943	$1,869	$762	$7,784	$828	$1	$17,153
Dominion	$36,308	$4,935	$9,651	$10,745	$7,510	$2,882	$29,996	$3,041	$5	$72,029
DPL	$7,438	$901	$1,691	$1,522	$706	$447	$6,093	$489	$1	$12,704
DLCO	$4,108	$623	$1,264	$1,464	$965	$366	$3,953	$418	$1	$8,790
EKPC	$4,559	$614	$1,299	$1,289	$817	$318	$3,477	$360	$1	$8,897
JCPL	$7,427	$911	$1,989	$1,863	$883	$566	$8,636	$681	$1	$13,639
Met-Ed	$5,815	$775	$1,522	$1,530	$814	$387	$4,433	$438	$1	$10,843
OVEC	$38	$6	$13	$13	$8	$3	$25	$3	$0	$81
PECO	$14,213	$1,755	$3,650	$3,583	$1,471	$903	$12,546	$1,012	$2	$25,575
PENELEC	$5,304	$860	$1,751	$1,940	$1,071	$410	$4,328	$454	$1	$11,336
Pepco	$11,147	$1,511	$2,897	$3,118	$2,155	$880	$9,303	$929	$1	$21,707
PPL	$15,052	$2,006	$4,004	$3,848	$1,699	$887	$10,966	$1,017	$2	$27,495
PSEG	$15,476	$1,711	$3,783	$3,709	$1,753	$1,034	$14,582	$1,206	$2	$27,467
RECO	$424	$59	$125	$136	$66	$42	$567	$47	$0	$852
Exports	$14,962	$1,827	$4,862	$5,507	$3,388	$990	$10,143	$1,029	$2	$31,536
Total	$272,811	$38,661	$79,605	$86,121	$50,976	$21,182	$241,725	$23,737	$35	$549,357

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in the first nine months of 2019.

Table 6-14 Zonal DR charge per MWh of load and exports: January through September 2019

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
AEP	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
APS	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
ATSI	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
BGE	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
ComEd	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
DAY	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
DEOK	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
Dominion	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
DPL	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
DLCO	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
EKPC	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
JCPL	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
Met-Ed	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
OVEC	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
PECO	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
PENELEC	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
Pepco	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
PPL	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
PSEG	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
RECO	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
Exports	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
Monthly Average	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges for 2018 through September 2019. The day-ahead DR charges decreased by $0.2 million, 32.3 percent, from $0.8 million in the first nine months of 2018 to $0.5 million in the first nine months of 2019. The real-time DR charges decreased $1.2 million, 79.9 percent, from $1.6 million in the first nine months of 2018 to $0.3 million in the first nine months of 2019.

Table 6-15 Monthly day-ahead and real-time economic DR charge: 2018 through September 2019

	Day-ahead DR Charge			Real-time DR Charge		
Month	2018	2019	Percent Change	2018	2019	Percent Change
Jan	$287,093	$150,139	(47.7%)	$381,071	$122,303	(67.9%)
Feb	$22,479	$22,811	1.5%	$77,584	$15,850	(79.6%)
Mar	$58,245	$71,143	22.1%	$125,482	$8,462	(93.3%)
Apr	$85,711	$84,808	(1.1%)	$140,688	$1,313	(99.1%)
May	$87,376	$47,488	(45.7%)	$143,598	$3,488	(97.6%)
Jun	$56,538	$18,261	(67.7%)	$101,014	$2,921	(97.1%)
Jul	$45,087	$81,306	80.3%	$153,191	$160,418	4.7%
Aug	$60,540	$19,893	(67.1%)	$308,315	$3,844	(98.8%)
Sep	$29,144	$0	(100.0%)	$152,727	$35	(100.0%)
Oct	$57,842			$40,317		
Nov	$32,131			$42,017		
Dec	$9,890			$6,369		
Total	$832,077	$495,849	(40.4%)	$1,672,373	$318,635	(80.9%)

Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer, annual and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year will require all emergency or pre-emergency demand resource to be registered as an annual capacity resource. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[36] With the implementation of Capacity Performance, a performance assessment interval (PAI) occurs when emergency or pre-emergency is dispatched. PJM effectively eliminated the difference between pre-emergency and emergency by making both trigger a PAI. To participate as an emergency or pre-emergency demand resource, the CSP must clear MW in an RPM auction. Emergency and pre-emergency resources receive capacity revenue from the capacity market and also receive energy revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency or pre-emergency event. 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.

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 that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[37]

The HHI for demand resources showed that ownership was highly concentrated for the 2018/2019 and 2019/2020 delivery years, with an HHI value of 1807 and 1838. In the 2018/2019 Delivery Year, the four largest companies contributed 78.1 percent of all committed demand resources UCAP MW and 78.8 percent of all committed demand resources UCAP MW in the 2019/2020 Delivery Year.

Table 6-16 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.

36 Summer period demand response has the same obligations as extended summer demand response. It must be available for June through October and the following May between 10:00AM and 10:00PM. *See* PJM OATT RAA Article 1.

37 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-16 HHI value for committed UCAP MW by LDA by delivery year: 2018/2019 and 2019/2020 delivery years[38]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2018/2019	RTO	3,387.6	2018	High
	MAAC	447.5	2473	High
	EMAAC	1,315.5	2156	High
	PSEG	143.4	2252	High
	PS-NORTH	95.6	2924	High
	PEPCO	533.7	5464	High
	ATSI	622.8	2573	High
	ATSI-CLEVELAND	150.5	4050	High
	COMED	1,938.6	2438	High
	BGE	493.2	5597	High
	PPL	496.2	2264	High
	DPL-SOUTH	500.4	8707	High
2019/2020	RTO	3,576.3	2018	High
	MAAC	463.8	2473	High
	EMAAC	900.3	2156	High
	PSEG	149.8	2252	High
	PS-NORTH	89.9	2924	High
	PEPCO	479.8	5464	High
	ATSI	705.9	2573	High
	ATSI-CLEVELAND	210.8	4050	High
	COMED	2,016.5	2438	High
	BGE	208.2	5597	High
	PPL	532.5	2264	High
	DPL-SOUTH	50.4	8707	High

Table 6-17 shows the committed demand response UCAP MW by delivery year. Total committed demand response UCAP MW in PJM increased by 257.6 MW, or 3.0 percent, from 8,727.0 MW in the 2018/2019 Delivery Year to 8,984.6 MW in the 2019/2020 Delivery Year. The DR percent of capacity increased by 0.1 percent, from 4.9 percent in the 2018/2019 Delivery Year to 5.0 percent in the 2019/2020 Delivery Year.

38 The RTO LDA refers to the rest of RTO.

Table 6-17 Committed demand response UCAP MW for PJM: 2011/2012 through 2019/2020 delivery year

Delivery Year	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
2011/2012	2,509.1	1.4%
2012/2013	7,632.4	4.4%
2013/2014	8,218.3	4.6%
2014/2015	8,665.9	4.8%
2015/2016	11,340.2	6.4%
2016/2017	8,862.6	5.0%
2017/2018	8,458.4	4.6%
2018/2019	8,727.0	4.9%
2019/2020	8,984.6	5.0%

Table 6-18 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2019. Capacity market revenue decreased in the first nine months of 2019 by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. Lower demand resource revenues were in part a result of lower capacity market prices in the 2019/2020 RPM auction. The capacity revenue in the first nine months of 2018 is from 2017/2018 RPM and 2018/2019 RPM auction clearing prices and the capacity revenue in the first nine months of 2019 is from 2018/2019 RPM and 2019/2020 RPM auction clearing prices. The annual capacity market prices decreased $64.77 per MW-day from $164.77 in the 2018/2019 Delivery Year to $100.00 in the 2019/2020 Delivery Year, a 39.3 percent increase.

Table 6-18 Zonal monthly capacity revenue: January through September, 2019

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$1,063,052	$960,176	$1,063,052	$1,028,760	$1,063,052	$436,515	$451,066	$451,066	$436,515	$6,953,251
AEP, EKPC	$7,363,738	$6,651,118	$7,363,738	$7,126,198	$7,363,738	$3,867,902	$3,996,832	$3,996,832	$3,867,902	$51,597,996
APS	$4,638,234	$4,189,373	$4,638,234	$4,488,614	$4,638,234	$2,285,119	$2,361,289	$2,361,289	$2,285,119	$31,885,504
ATSI	$4,254,499	$3,842,773	$4,254,499	$4,117,257	$4,254,499	$2,344,392	$2,422,538	$2,422,538	$2,344,392	$30,257,388
BGE	$1,471,812	$1,329,378	$1,471,812	$1,424,334	$1,471,812	$630,148	$651,153	$651,153	$630,148	$9,731,748
ComEd	$11,763,628	$10,625,212	$11,763,628	$11,384,156	$11,763,628	$9,639,882	$9,961,211	$9,961,211	$9,639,882	$96,502,438
DAY	$1,082,665	$977,891	$1,082,665	$1,047,740	$1,082,665	$533,882	$551,678	$551,678	$533,882	$7,444,747
DEOK	$996,130	$899,730	$996,130	$963,997	$996,130	$608,291	$628,567	$628,567	$608,291	$7,325,835
DLCO	$3,841,793	$3,470,007	$3,841,793	$3,717,864	$3,841,793	$1,760,122	$1,818,792	$1,818,792	$1,760,122	$25,871,078
Dominion	$2,760,840	$2,493,662	$2,760,840	$2,671,780	$2,760,840	$1,133,435	$1,171,216	$1,171,216	$1,133,435	$18,057,265
DPL	$1,229,930	$1,110,904	$1,229,930	$1,190,255	$1,229,930	$599,460	$619,442	$619,442	$599,460	$8,428,752
JCPL	$1,324,124	$1,195,983	$1,324,124	$1,281,410	$1,324,124	$605,867	$626,062	$626,062	$605,867	$8,913,624
Met-Ed	$1,527,708	$1,379,865	$1,527,708	$1,478,427	$1,527,708	$775,740	$801,598	$801,598	$775,740	$10,596,093
OVEC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PECO	$3,342,110	$3,018,680	$3,342,110	$3,234,300	$3,342,110	$1,582,953	$1,635,718	$1,635,718	$1,582,953	$22,716,652
PENELEC	$1,811,449	$1,636,148	$1,811,449	$1,753,015	$1,811,449	$830,090	$857,760	$857,760	$830,090	$12,199,210
Pepco	$806,881	$728,796	$806,881	$780,853	$806,881	$142,570	$147,322	$147,322	$142,570	$4,510,076
PPL	$2,314,965	$2,090,936	$2,314,965	$2,240,289	$2,314,965	$1,801,961	$1,862,026	$1,862,026	$1,801,961	$18,604,095
PSEG	$2,521,890	$2,277,836	$2,521,890	$2,440,539	$2,521,890	$1,157,439	$1,196,021	$1,196,021	$1,157,439	$16,990,965
RECO	$48,971	$44,232	$48,971	$47,392	$48,971	$30,889	$31,919	$31,919	$30,889	$364,154
Total	$54,164,419	$48,922,701	$54,164,419	$52,417,179	$54,164,419	$30,766,656	$31,792,211	$31,792,211	$30,766,656	$388,950,870

Table 6-19 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2012/2013 through 2018/2019 delivery years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[39] Only Kentucky has been authorized by the Commission.[40] Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources committed increased by 20.2 percent from 2,117.9 MW in the 2017/2018 Delivery Year to 2,545.1 MW in the 2018/2019 Delivery Year.[41]

Table 6-19 Energy efficiency resources (MW): June 1, 2012 to June 1, 2018

	UCAP (MW)
	RPM Commitments
01-Jun-12	631.2
01-Jun-13	1,024.8
01-Jun-14	1,282.4
01-Jun-15	1,525.5
01-Jun-16	1,784.3
01-Jun-17	2,117.9
01-Jun-18	2,545.1

Figure 6-3 shows the amount of installed EE MW in PJM by technology for the 2018/2019 and 2019/2020 delivery years. An installed EE resource may participate as a capacity resource for up to a maximum of four consecutive delivery years.[42] The lighting category consists of more efficient lighting technology installed, HVAC consists of more efficient HVAC technology installed, new construction consists of more efficient equipment than the industry average for individual components, appliances consists of more efficient appliances and prescriptive consists of more efficient equipment procured by an incentive program for lighting, HVAC or appliances. Prescriptive energy efficiency MW have an assumed savings calculated by an expected installation rate dependent on units sold and the difference between the current average electricity usage of what is being replaced and the new product. For example, if 100 lights are sold, an expected installation rate could be that 95 are installed and replacing a light that consumes more electricity. Instead of measuring each light replaced, the EE provider takes the difference between the industry average and the new light. Prescriptive energy efficiency MW comprise 87.2 percent of all energy efficiency MW in the 2018/2019 Delivery Year and 86.5 percent in the 2019/2020 Delivery Year. The measurement and verification method for prescriptive energy efficiency projects relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant.

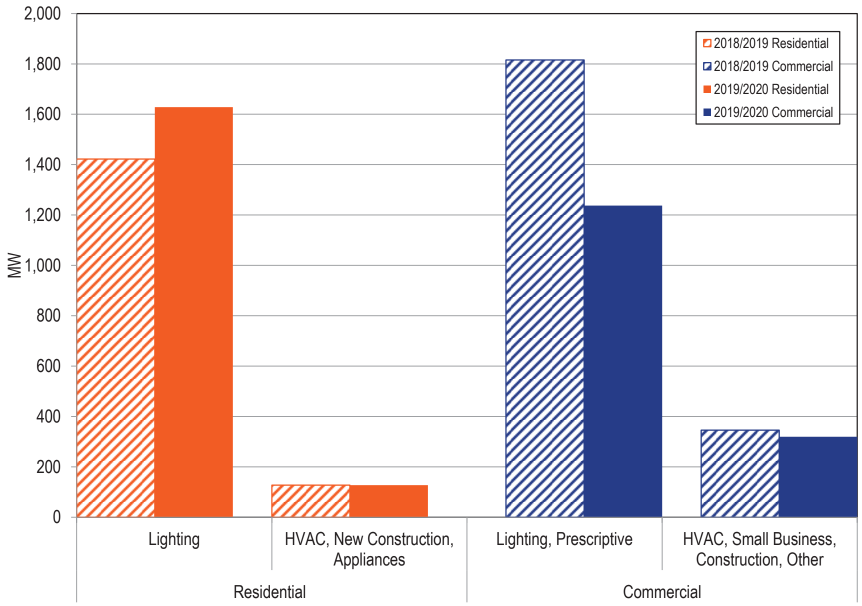
39 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).
40 The Commission made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE, explaining that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 67.
41 See the *2018 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.
42 PJM. "Manual 18: Capacity Market," § 4.4, Rev. 42 (July 25, 2019).

All EE resources must submit pre and post installation M&V plans that include the variables that affect the project's electrical demand, baseline consumption, post installation consumption, and specifications of the equipment or types of equipment used in the project. The nonprescriptive measurement and verification methods do not use full metering but rely on samples and assumptions and only for limited periods.[43] The nominated EE value is the expected average demand reduction during: the peak hours ending 15:00 EPT through 18:00 EPT for June 1 through August 31; and the peak hours ending 8:00 EPT through 9:00 EPT and 19:00 EPT through 20:00 EPT for all days between January 1 and February 28, of the relevant delivery year.[44] The calculated MW are offered in PJM's Capacity Market as EE. The installed EE resources for the 2018/2019 Delivery Year include any installed EE resource between June 1, 2014 and May 31, 2018, and installed EE resources for the 2019/2020 Delivery Year include any installed EE resources between June 1, 2015 and May 31, 2019.

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. Energy efficiency measures reduce energy usage and capacity usage directly. The reduced market payments are the appropriate compensation. PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag.

43 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 3 (November 17, 2016).
44 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 1.1 Rev. 3 (November 17, 2016).

Figure 6-3 Installed energy efficiency MW by type: 2018/2019 and 2019/2020 delivery years



FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[45] The quick lead time demand response was defined after demand resources cleared in the RPM base residual auctions for the 2014/2015, 2015/2016, 2016/2017 and 2017/2018 delivery years. PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[46] The quick lead time is the default lead time starting June 1, 2015, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[47] 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.[48] Once a location is granted a longer lead time,

45 See 147 FERC ¶ 61,103 (2014).
46 See PJM Interconnection, L.L.C., Docket No. ER14-135-000 (October 20, 2014).
47 See "PJM Manual 18: Capacity Market," § 4.3.1, Rev. 42 (July 25, 2019).
48 "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 42 (July 25, 2019).

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 6-20 shows the amount of nominated MW and locations by product type and lead time for the 2018/2019 Delivery Year. PJM approved 3,022 locations, or 20.6 percent of all locations, which have 3,944.1 nominated MW, or 43.9 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2018/2019 Delivery Year.[49]

Table 6-20 Nominated MW and locations by product type and lead time: 2018/2019 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Annual	Base	Capacity Performance	Pre-Emergency Total	Limited	Annual	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	311.9	6.8	4,179.5	305.2	4,803.3	0.2	0.0	221.6	18.9	240.7	5,044.0
Short Lead (60 Minutes)	23.2	0.0	367.8	65.5	456.5	0.0	0.0	26.4	0.0	26.4	483.0
Long Lead (120 Minutes)	122.8	0.0	2,666.4	527.7	3,316.9	0.0	0.0	144.2	0.0	144.2	3,461.1
Total	457.8	6.8	7,213.6	898.4	8,576.7	0.2	0.0	392.3	18.9	411.4	8,988.1
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Annual	Base	Capacity Performance	Pre-Emergency Total	Limited	Annual	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	167	2	10,154	732	11,055	4	0	518	57	579	11,634
Short Lead (60 Minutes)	12	0	297	30	339	0	0	42	0	42	381
Long Lead (120 Minutes)	33	0	2,010	379	2,422	0	0	219	0	219	2,641
Total	212	2	12,461	1,141	13,816	4	0	779	57	840	14,656

Table 6-21 shows the amount of nominated MW and locations by product type and lead time for the 2019/2020 Delivery Year. PJM approved 3,106 locations, or 20.9 percent of all locations, which have 3,902.1 nominated MW, or 40.6 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2019/2020 Delivery Year.

Table 6-21 Nominated MW and locations by product type and lead time: 2019/2020 Delivery Year

	Pre-Emergency MW			Emergency MW			
Lead Type	Base	Capacity Performance	Pre-Emergency Total	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	5,298.4	159.1	5,457.5	238.4	17.7	256.1	5,713.6
Short Lead (60 Minutes)	326.7	36.3	363.0	27.2	0.0	27.2	390.3
Long Lead (120 Minutes)	2,933.8	428.2	3,362.0	148.3	1.4	149.8	3,511.8
Total	8,558.9	623.6	9,182.6	414.0	19.1	433.1	9,615.7
	Pre-Emergency Locations			Emergency Locations			
Lead Type	Base	Capacity Performance	Pre-Emergency Total	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	10,886	356	11,242	514	26	540	11,782
Short Lead (60 Minutes)	288	8	296	53	0	53	349
Long Lead (120 Minutes)	2,048	425	2,473	281	3	284	2,757
Total	13,222	789	14,011	848	29	877	14,888

49 For analysis of the 2017/2018 Delivery Year, *see 2018 Quarterly State of the Market Report: January through September*, Section 6: Demand Response, at Emergency and Pre-Emergency Programs. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm-sec6.pdf>.

There are two different 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 real-time load, multiplied by the loss factor (LF).[50] 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.[51] 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.[52] 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.[53]

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.[54] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[55] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

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

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

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

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

Table 6-22 shows the MW registered by measurement and verification method and by technology type for the 2018/2019 Delivery Year. For the 2018/2019 Delivery Year, 99.7 percent use the FSL method and 0.3 percent use the GLD measurement and verification method.

50 Real-time load is hourly metered load.
51 135 FERC ¶ 61,212.
52 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 42 (July 25, 2019).
53 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev.42 (July 25, 2019).
54 OATT Attachment DD.5.11.
55 OATT Attachment M-2.

Table 6-22 Reduction MW by each demand response method: 2018/2019 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	1,056.4	2,857.5	178.8	849.5	3,856.2	116.6	45.7	8,960.6	99.7%
Guaranteed Load Drop	0.8	8.8	0.0	0.7	16.4	0.1	0.5	27.4	0.3%
Total	1,057.2	2,866.3	178.8	850.2	3,872.6	116.6	46.2	8,988.0	100.0%
Percent by method	11.8%	31.9%	2.0%	9.5%	43.1%	1.3%	0.5%	100.0%	

Table 6-23 shows the MW registered by measurement and verification method and by technology type for the 2019/2020 Delivery Year. For the 2019/2020 Delivery Year, 99.7 percent use the FSL method and 0.3 percent use the GLD measurement and verification method.

Table 6-23 Reduction MW by each demand response method: 2019/2020 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	1,053.1	3,239.0	187.8	940.3	3,923.8	122.5	51.1	9,517.6	99.7%
Guaranteed Load Drop	0.4	12.3	0.0	1.4	15.1	0.1	0.3	29.5	0.3%
Total	1,053.5	3,251.2	187.8	941.8	3,938.8	122.6	51.4	9,547.1	100.0%
Percent by method	11.0%	34.1%	2.0%	9.9%	41.3%	1.3%	0.5%	100.0%	

Table 6-24 shows the fuel type used in the onsite generators for the 2018/2019 Delivery Year in the emergency and pre-emergency programs. During the 2018/2019 Delivery Year, 1,057.2 MW of the 8,988.0 MW of nominated MW, 11.8 percent, used onsite generation. Of the 1,057.2 MW, 82.7 percent of MW are diesel and 17.3 percent of MW are natural gas, gasoline, oil, propane or waste products. For the 2018/2019 Delivery Year, there was 354.5 MW of the 411.4 MW, 86.2 percent, registered with an onsite generator in the emergency program.

Table 6-24 Onsite generation fuel type (MW): 2018/2019 Delivery Year

	2018/2019	
Fuel Type	MW	Percent
Diesel	874.4	82.7%
Natural Gas, Gasoline, Oil, Propane, Waste Products	182.8	17.3%
Total	1,057.2	100.0%

Table 6-25 shows the fuel type used in the onsite generators for the 2019/2020 Delivery Year in the emergency and pre-emergency programs. During the 2019/2020 Delivery Year, 1,053.5 MW of the 9,547.1 MW of nominated MW, 11.0 percent, used onsite generation. Of the 1,053.5 MW, 85.9 percent of MW are diesel and 14.1 percent of MW are natural gas, gasoline, oil, propane or waste products. For the 2019/2020 Delivery Year, there were 284.9 MW of the 433.1 MW, 65.7 percent, registered with an onsite generator in the emergency program.

Table 6-25 Onsite generation fuel type (MW): 2019/2020 Delivery Year

	2019/2020	
Fuel Type	MW	Percent
Diesel	905.3	85.9%
Natural Gas, Gasoline, Oil, Propane, Waste Products	148.2	14.1%
Total	1,053.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

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.[56] PJM does not measure compliance when demand response is dispatched in a subzone created on the same day as the dispatch. There are thirteen dispatchable subzones in PJM effective September 21, 2018: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK.[57] 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.[58]

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 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.[59] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources 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.[60] 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 limited, extended summer and annual 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. Limited, extended summer and annual 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 limited, extended summer and annual 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

56 OATT Attachment DD, Section 11.
57 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed February 25, 2019).
58 OATT Attachment DD, Section 10A.
59 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 in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).
60 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.

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 limited, extended summer and annual 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.[61]

Annual and capacity performance demand response currently assign annual reduction capability by registration, which is measured as the lower of the summer and winter reduction capability. Starting with the 2019/2020 Delivery Year, CSPs will assign the annual reduction capability by portfolio rather than registration, which is measured as the lower of the summer and winter reduction capability by portfolio.[62] Allowing CSPs to aggregate to the portfolio level further weakens the locational aspect of registered demand resources and artificially inflates the level of demand response. For example, imagine a CSP has two registrations in a zonal portfolio, with one registration capable of reducing 5 MW in summer and 2 MW in winter, and the second registration capable of reducing 1 MW in summer and 5 MW in winter. Before the 2019/2020 Delivery Year, the first registration would have an annual capability of 2 MW and the second registration would have an annual capability of 1 MW resulting in a 3 MW total reduction capability. After the 2019/2020 Delivery Year, individual registration capability is ignored resulting in the portfolio capability of 6 MW in summer and 7 MW in winter. This creates a 6 MW total reduction capability within the zone. Without any change to either registration, the CSP was able to add 3 MW to their annual reduction capability. The locational availability of demand resources, at a nodal level, will vary. This treatment is unique to demand resources.

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).[63] 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 6-26 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin as of June 1, for 2017, 2018 and 2019. There are 8,988.1 nominated MW of demand response for the 2018/2019 Delivery Year, which is 40.0 percent of the required reserve margin and 28.1 percent of the actual reserve margin on June 1, 2018.[64] There are 9,547.1 nominated MW of demand response for the 2019/2020 Delivery Year, which is 42.8 percent of the required reserve margin and 24.2 percent of the actual reserve margin on June 1, 2019.

Table 6-26 Demand response nominated MW compared to reserve margin: June 1, 2017 through 2019

	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
01-Jun-17	9,154.7	23,305.2	39.3%	33,828.1	27.1%
01-Jun-18	8,998.1	22,487.7	40.0%	31,987.5	28.1%
01-Jun-19	9,547.1	22,297.5	42.8%	39,401.6	24.2%

PJM will dispatch demand resources by zone or subzone for limited, extended summer and annual 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

61 "PJM Manual 18: Capacity Market," § 8.7A, Rev. 42 (July 25, 2019).
62 The seasonal DR registration aggregation received endorsement at the September 27, 2018 MRC meeting, <https://www.pjm.com/-/media/committees-groups/committees/mc/20180927/20180927-consent-agenda-item-b-seasonal-dr-registration-aggregation-draft-oatt-revisions.ashx>.
63 OATT § 1 (Performance Assessment Hour).
64 *2018 State of the Market Report for PJM*, Volume 2, Section 5: Capacity, Table 5-7.

(EAA).[65] [66] 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.

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.[67]

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.

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

65 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.

66 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 42 July 25, 2019).

67 OA Schedule 1 § 8.9.

a zero MW reduction value.[68] 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.[69] 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.

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 that demand reductions based entirely on behind the meter generation be capped 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."[70] 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 DR 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.[71] 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

68 OA Schedule 1 § 8.9.
69 157 FERC ¶ 61,067 (2016).
70 OA Schedule 1 § 8.2.
71 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>.

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.[72]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[73] 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 6-27 shows the test penalties by delivery year by product type for the 2015/2016 Delivery Year through the 2018/2019 Delivery Year. 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 for the limited product is open through September. The testing window for the extended summer, annual and Capacity Performance product is open through the end of the delivery year.

Emergency 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.[74] There were 98.2 percent of nominated MW for the 2017/2018 Delivery Year and 98.8 percent of nominated MW for the 2018/2019 Delivery Year registered under the full program option. There were 1.8 percent of nominated MW for the 2017/2018 Delivery Year and 1.2 percent of nominated MW for the 2018/2019 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

Table 6-27 Test penalties by delivery year by product type: 2015/2016 through 2018/2019

	2015/2016			2016/2017			2017/2018			2018/2019		
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
Limited	96.4	$165.35	$5,836,255	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665	0.0	$179.80	$2,100
Extended Summer	1.9	$163.70	$113,835	7.3	$138.14	$370,290	10.5	$142.86	$547,928			
Annual	3.7	$184.67	$250,621	4.8	$137.45	$241,406	16.3	$144.00	$855,940			
Base DR and EE										16.3	$186.80	$1,110,134
Capacity Performance				2.1	$160.80	$124,310	0.6	$181.80	$40,146			
Total	102.0	$166.02	$6,200,711	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678	16.3	$186.79	$1,112,234

72 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.

73 The mandatory response time for Limited DR is June through September between 12:00PM to 8:00PM EPT, for Extended Summer is June through October and the following May between 10:00AM to 10:00PM EPT, for Annual DR is June through October and the following May between 10:00AM to 10:00PM and is November through April between 6:00AM to 9:00PM EPT, for Base Capacity DR is June through September between 10:00AM to 10:00PM EPT, 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: Capacity Market," Rev. 42 (July 25, 2019).

74 *Id.*

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."[75] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2017/2018 Delivery Year and the 2018/2019 Delivery Year.[76] [77] 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.[78] 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.[79]

Table 6-28 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2018/2019 Delivery Year. The majority of participants, 76.8 percent of locations and 53.9 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2018/2019 Delivery Year, 2.3 percent of locations and 4.0 percent of nominated MW have a dispatch price between $0 and $1,000 per MWh, and 97.7 percent of locations and 96.0 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 $173.97 per location and $130.17 per nominated MW.

Table 6-28 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2018/2019 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	338	2.3%	350.6	4.0%	$69.18	$55.03
$1,000-$1,275	2,666	18.4%	3,355.9	37.9%	$173.97	$130.17
$1,275-$1,550	361	2.5%	380.6	4.3%	$51.11	$48.48
$1,550-$1,849	11,159	76.8%	4,775.2	53.9%	$51.43	$120.18
Total	14,524	100.0%	8,862.3	100.0%	$74.33	$121.81

Table 6-29 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2019/2020 Delivery Year. The majority of participants, 75.3 percent of locations and 56.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2019/2020 Delivery Year, 3.6 percent of locations and 3.6 percent of nominated MW have a dispatch price between $0 and $1,000 per MWh, and 96.4 percent of locations and 96.4 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $181.51 per location and $141.57 per nominated MW.

75 161 FERC ¶ 61,153 (2017).
76 139 FERC ¶ 61,057 (2012).
77 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.
78 OATT Attachment K Appendix Section 1.10.1A Day-ahead Energy Market Scheduling (d) (x).
79 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 32 (May 13, 2019).

Table 6-29 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2019/2020 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	530	3.6%	339.5	3.6%	$46.98	$86.48
$1,000-$1,275	2,761	18.8%	3,397.5	35.9%	$181.51	$141.57
$1,275-$1,550	350	2.4%	364.9	3.9%	$57.49	$55.14
$1,550-$1,849	11,073	75.3%	5,370.6	56.7%	$49.77	$102.62
Total	14,714	100.0%	9,472.5	100.0%	$74.57	$115.84

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 6-24 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2018/2019 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 DR payments when DR 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 DR 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.

80 Some energy storage facilities may be DERs. The February 15, 2018, FERC Order No. 841 requires that energy storage resources have access to capacity, energy and ancillary service markets. 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).