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 2018, total demand response revenue increased by $64.0 million, 17.2 percent, from $371.1 million in the first nine months of 2017 to $435.1 million in the first nine months of 2018. Emergency demand response revenue accounted for 98.0 percent of all demand response revenue, economic demand response for 0.5 percent, demand response in the Synchronized Reserve Market for 1.0 percent and demand response in the regulation market for 0.5 percent.

  Total emergency demand response revenue increased by $60.9 million, 16.7 percent, from $365.4 million in the first nine months of 2017 to $426.3 million in the first nine months of 2018. This increase consisted entirely of capacity market revenue.[2]

  Economic demand response revenue increased by $101.2 thousand, 4.7 percent, from $2,167.6 thousand in the first nine months of 2017 to $2,268.7 thousand in the first nine months of 2018.[3] Demand response revenue in the Synchronized Reserve Market increased by $2.0 million, 87.3 percent, from $2.3 million in the first nine months of 2017 to $4.2 million in the first nine months of 2018. Demand response revenue in the regulation market increased by $1.0 million, 78.5 percent, from $1.3 million in the first nine months of 2017 to $2.3 million in the first nine months of 2018.

- **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 the first nine months of 2017 and 2018. The HHI for economic resource reductions increased from 7590 in the first nine months of 2017 to 7705 in the first nine months of 2018. The ownership of emergency demand response resources was moderately concentrated in the first nine months of 2018. The HHI for emergency demand response committed MW was 1433 for the 2017/2018 Delivery Year and 1922 for the 2018/2019 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all committed emergency demand response MW. In the 2018/2019 Delivery Year, the four largest companies contributed 77.9 percent of all committed emergency demand response MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources 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

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 11, 2018 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," Rev. 80 (June. 1, 2018) at 83.

demand resources in a nodal market would improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation 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, 2018.

- 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 an economic resource, 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 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 eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that 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.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)

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

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

- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that 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 there be only one demand response product in the capacity market, with an obligation to respond when called for all hours of the 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 PAH to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Status: Adopted 2014.)

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 the value of the uses of the power and on the actual cost of that power.

7 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

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.

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. 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 to 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 an hourly 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 current proposals at the Summer-Only Demand Response Senior Task Force (SODRSTF) are 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. Under the MMU proposal, 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.[8] PJM will incorporate the associated load reduction in the load forecast. 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.[9] Other proposals would continue to rely on load estimates rather than metered load to calculate actual demand.

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 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.

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 *Summer-Only Demand Response Senior Task Force*, PJM, <http://www.pjm.com/committees-and-groups/task-forces/sodrstf.aspx>, (Accessed August 3, 2018).

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

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

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.[11] In all demand response programs, CSPs are companies that seek to sign up end-use 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. PRD does not receive 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.[12] PRD does not have to respond during performance assessment hours (PAH) 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 PAH to be consistent with all CP resources. PRD cleared the capacity market in the BRA for the first time for the 2020/2021 Delivery Year.

10 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.

11 OA Schedule 1 § 8.5.

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

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.[13] 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.

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.

On July 16, 2008, the Commission directed PJM to amend their market rules to accept bids from aggregators of retail customers of utilities with the permission of the relevant electric retail regulatory authority ("RERRA").[14] PJM implemented rules that require small EDCs to demonstrate approval of participation by the RERRA and require large EDCs to demonstrate that the RERRA has not prohibited participation.[15] [16] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.[17]

Figure 6-1 shows all revenue from PJM demand response programs by market for the first nine months of 2008 through 2018. Since the implementation of the RPM Capacity Market on June 1, 2007, demand resources (capacity market) have been the primary source of demand response revenue.[18] In the first nine months of 2018, total demand response revenue increased by $64.0 million, 17.2 percent, from $371.1 million in the first nine months of 2017 to $435.1 million in the first nine months of 2018. Total emergency demand response revenue increased by $60.9 million, 16.7 percent, from $365.4 million in the first nine months of 2017 to $426.3 million in the first nine months of 2018. This increase consisted entirely of capacity market revenue.[19] In the first nine months of 2018, demand resource revenue, which includes capacity and emergency energy revenue, accounted for 98.0 percent of all revenue received by demand response providers, the economic program for 0.5 percent, synchronized reserve for 1.0 percent and the regulation market for 0.5 percent.

Economic demand response revenue increased by $101.2 thousand, 4.7 percent, from $2,167.6 thousand in the first nine months of 2017 to $2,268.7 thousand in the first nine months of 2018.[20] Demand response revenue in the Synchronized Reserve Market increased by $2.0 million, 87.3 percent, from $2.3 million in the first nine months of 2017 to $4.2 million in the first nine months of 2018. Demand response revenue in the regulation market increased by $1.0 million, 78.5 percent, from $1.3 million in the first nine months of 2017 to $2.3 million in the first nine months of 2018.

Higher demand resource revenues were in part a result of higher capacity market prices in the first nine months of 2018. The capacity revenue in 2017 is from 2016/2017 and 2017/2018 RPM auction clearing prices and the capacity revenue in 2018 is from 2017/2018 and 2018/2019 RPM auction clearing prices. Average capacity market prices increased $34.39 per MW-day from $141.19 in the 2017/2018 Delivery Year to $175.58 in the 2018/2019 Delivery Year, a 24.4 percent increase.[21]

13 *2018 Quarterly State of the Market Report for PJM: January through September*, Section 8: Environmental and Renewables, Table 8-6.

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

15 OA Schedule 1 § 1.5A.3.01. *An EDC is classified as a small EDC if it distributes less than four million MWh in the last fiscal year.*

16 The evidence supplied 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.

17 *Id.*; *see, e.g.*, *Bear Island Paper Company, L.P.*, Va. S.C.C. Case No. PUE-2009-00133 (March 10, 2010); Petition for Approval of Demand Response Program and Associated Demand Response Tariffs on Behalf of Kingsport Power Company, Etc., Tenn. PUC, 304 P.U.R.4th 224 (March 1, 2013); *Application of East Kentucky Power Cooperative, Inc. for a Declaratory Order, Etc.*, 2017 Ky. P.U.C. LEXIS 569 (June 06, 2017); *The Investigation by the Commission of Relevant Electric Retail Regulatory Authority in Southern Maryland Electric Cooperative Service Territory*, 2017 Ky. 2009 Md. PSC LEXIS 32 (April 27, 2009).

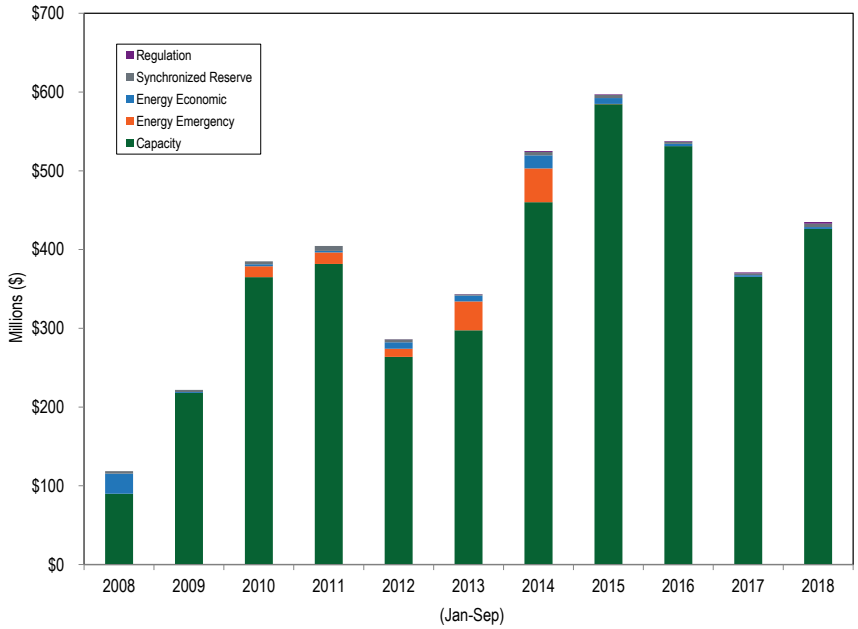
18 This includes both capacity market revenue and emergency energy revenue for capacity resources.

19 The total credits and MWh for demand resources were calculated as of October 17, 2018 and may change as a result of continued PJM billing updates. There was no emergency energy revenue in the first nine months of 2018.

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

21 *2018 Quarterly State of the Market Report for PJM: January through September*, Section 7: Net Revenues, Table 7-6.

Figure 6-1 Demand response revenue by market: January through September, 2008 through 2018



Economic Program

FERC Order No. 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[22] 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."[23] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of Order 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, 2014, through September 30, 2018. 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 2018 compared to the first nine months of 2017. Average monthly registrations decreased by 298, 39.6 percent, from 753 in the first nine months of 2017 to 455 in the first nine months of 2018. Average monthly registered MW increased by 491 MW, 23.2 percent, from 2,113 MW in the first nine months of 2017 to 2,604 MW in the first nine months of 2018.

Most demand response resources are registered for both the economic and emergency demand response programs. There were 1,671 registrations and 1,265 nominated MW in the emergency program also registered in the economic program during the first nine months of 2018.

22 157 FERC ¶ 61,115 (2016).
23 *Id.* at 8.

Table 6-2 Economic program registrations on the last day of the month: 2014 through September 2018[24]

	2014		2015		2016		2017		2018	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,180	2,325	1,078	2,960	838	2,557	871	2,603	537	2,570
Feb	1,174	2,330	1,076	2,956	835	2,557	842	2,578	537	2,628
Mar	1,185	2,692	1,075	2,949	834	2,556	850	2,576	519	2,641
Apr	1,194	2,827	1,076	2,938	832	2,556	897	2,574	501	2,624
May	745	2,511	980	2,846	829	2,545	977	2,626	471	2,615
Jun	928	2,943	871	2,614	518	2,500	577	1,305	397	2,576
Jul	1,036	3,006	870	2,609	519	2,421	589	1,548	374	2,591
Aug	1,080	3,033	869	2,609	805	2,569	590	1,541	382	2,608
Sep	1,077	2,919	867	2,608	831	2,608	588	1,663	379	2,583
Oct	1,060	2,943	858	2,568	822	2,564	574	1,660		
Nov	1,063	2,995	851	2,566	820	2,564	559	1,662		
Dec	1,071	2,923	850	2,566	807	2,561	556	1,659		
Avg	1,067	2,732	974	2,788	774	2,547	706	2,000	455	2,604

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. Table 6-3 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through September 30, 2018. 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 decreased by 535 MW, 44.3 percent, from 1,209 MW in the first nine months of 2017 to 674 MW in the first nine months of 2018.[25] The peak dispatched MW in the first nine months of 2018, 674 MW, were 1,930 MW less than the average MW registered in the first nine months of 2018, 2,604 MW.

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through 2018

	Sum of Peak MW Reductions for all Registrations per Month								
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	183	132	110	193	446	169	139	123	142
Feb	121	89	101	119	307	336	128	83	70
Mar	115	81	72	127	369	198	120	111	71
Apr	111	80	108	133	146	143	118	54	71
May	172	98	143	192	151	161	131	169	70
Jun	209	561	954	433	483	833	121	240	105
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518
Aug	794	161	952	497	358	272	249	141	466
Sep	276	84	451	530	795	816	263	140	55
Oct	118	81	242	168	214	136	150	88	
Nov	111	86	165	155	166	127	116	81	
Dec	114	88	98	168	155	122	147	83	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	674

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

24 Data for years 2010 through 2013 are available in the *2017 State of the Market Report for PJM*.

25 The total credits and MWh numbers for demand resources were calculated as of October 11, 2018 and may change as a result of continued PJM billing updates.

under the net benefits test for that month.[26] 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 for the first nine months of 2010 through 2018. The average credits per MWh paid increased by $7.56 per MWh, 17.2 percent, from $43.94 per MWh in the first nine months of 2017 to $51.50 per MWh in the first nine months of 2018. The load-weighted, average LMP was 29.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $39.43 per MWh versus $30.36 per MWh. Curtailed energy for the economic program decreased by 5,277 MWh, 10.7 percent, from 49,331 MWh in the first nine months of 2017 to 44,054 MWh in the first nine months of 2018. Total credits paid for economic DR in 2017 increased by $0.1 million, 4.7 percent, from $2.2 million in the first nine months of 2017 to $2.3 million in the first nine months of 2018.

Table 6-4 Credits paid to the PJM economic program participants: January through September, 2010 through 2018

(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	44,054	$2,268,741	$51.50

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. 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. 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, 2018.

Figure 6-2 Economic program credits and MWh by month: January 2010 through September 2018

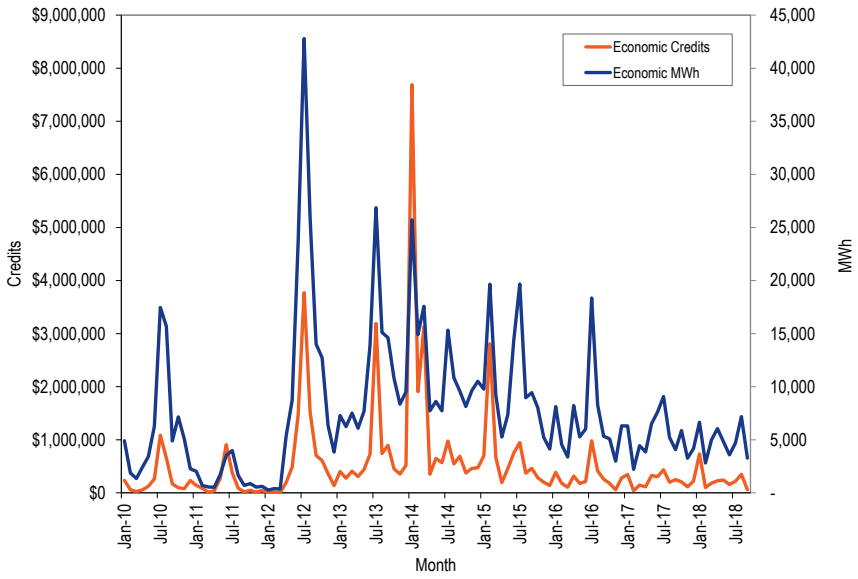


Table 6-5 shows performance for the first nine months of 2017 and 2018 in the economic program by control zone. Total reductions under the economic program decreased by 5,277 MWh, 10.7 percent, from 49,331 MW in the first nine months of 2017 to 44,054 MW in the first nine months of 2018. Total

26 "PJM Manual 28: Operating Agreement Accounting," Rev. 80 (June 1, 2018) at 78.

revenue under the economic program increased by $165 thousand, 7.8 percent, from $2,103 thousand in the first nine months of 2017 to $2,268 thousand in the first nine months of 2018.[27]

Table 6-5 PJM economic program participation by zone: January through September, 2017 and 2018

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change
AECO	$0.00		NA	0		NA			
AEP	$8.84	$931.88	10,437.8%	0	19	8,977.3%	$42.19	$48.98	16.1%
APS	$19,639.25	$53,190.92	170.8%	433	967	123.1%	$45.31	$55.00	21.4%
ATSI	$191,906.75	$832,887.85	334.0%	3,943	18,659	373.2%	$48.67	$44.64	(8.3%)
BGE	$132,833.56	$152,018.22	14.4%	2,500	2,692	7.7%	$53.14	$56.47	6.3%
ComEd	$136,111.86	$166,471.62	22.3%	3,959	4,504	13.8%	$34.38	$36.96	7.5%
DEOK	$21,122.21	$18,452.47	(12.6%)	159	134	(15.3%)	$133.21	$137.42	3.2%
Dominion	$513,393.00	$38,008.47	(92.6%)	7,862	177	(97.8%)	$65.30	$214.94	229.2%
DPL	$0.00		NA	516		NA			
JCPL	$85,579.20	$250,025.99	192.2%	1,242	3,612	190.9%	$68.92	$69.22	0.4%
Met-Ed	$9,875.96	$26,246.36	165.8%	223	607	172.0%	$44.28	$43.26	(2.3%)
PECO	$71,742.12	$48,699.68	(32.1%)	414	687	66.0%	$173.33	$70.90	(59.1%)
PENELEC	$275,864.41	$201,208.18	(27.1%)	8,392	3,745	(55.4%)	$32.87	$53.73	63.4%
Pepco	$0.00		NA	1,095		NA			
PPL	$62,661.42	$123,065.61	96.4%	1,578	1,072	(32.1%)	$39.70	$114.85	189.3%
PSEG	$582,188.38	$357,533.70	(38.6%)	17,014	7,179	(57.8%)	$34.22	$49.80	45.5%
Total	$2,102,926.95	$2,267,809.08	7.8%	49,331	44,054	(10.7%)	$42.63	$51.48	20.8%

Table 6-6 shows total settlements submitted for the first nine months of 2010 through 2018. 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 2018

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

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through September, 2010 through 2018

	2010		2011		2012		2013		2014		2015		2016		2017		2018	
	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	16	257	15	203	22	428	20	273	16	154	18	144	12	58	13	72	13	49

27 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 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year for the first nine months of 2010 through 2018. The number of active participants decreased by 23, 31.9 percent, from 72 in the first nine months of 2017 to 49 in the first nine months of 2018. All participants must be registered through a CSP.

The ownership of economic demand response resources was highly concentrated in 2017 and the first nine months of 2018.[28] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2017 through September 30, 2018. Table 6-8 also lists the share of reductions provided by, and the share of credits claimed by the four largest parent companies in each year. In the first nine months of 2018, 81.1 percent of all economic DR reductions and 84.3 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response increased 115 points, 1.5 percent, from 7590 in the first nine months of 2017 to 7705 in the first nine months of 2018.

Table 6-8 HHI and market concentration in the economic program: January 2017 through September 2018[29]

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2017	2018	Percent Change	2017	2018	Change in Percent	2017	2018	Change in Percent
Jan	8952	6572	(26.6%)	99.7%	92.2%	7.5%	99.6%	89.6%	10.0%
Feb	9263	8308	(10.3%)	100.0%	99.2%	0.8%	100.0%	99.1%	0.9%
Mar	8170	7495	(8.3%)	99.4%	96.0%	3.4%	98.1%	95.7%	2.4%
Apr	6099	6827	11.9%	100.0%	97.3%	2.7%	100.0%	97.2%	2.8%
May	7046	6685	(5.1%)	97.5%	98.3%	(0.8%)	92.7%	97.9%	(5.2%)
Jun	7702	8375	8.7%	91.6%	97.4%	(5.8%)	88.6%	96.2%	(7.5%)
Jul	7793	8256	5.9%	87.5%	90.2%	(2.7%)	77.6%	82.7%	(5.1%)
Aug	8006	7774	(2.9%)	99.5%	88.9%	10.6%	99.5%	87.3%	12.2%
Sep	7877	9619	22.1%	94.9%			87.8%		
Oct	6467			97.6%			97.8%		
Nov	7334			96.9%			96.4%		
Dec	7493			94.3%			89.0%		
Total	7590	7705	1.5%	87.2%	81.6%	(5.5%)	85.9%	86.4%	0.5%

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2017 and 2018. In the first nine months of 2017, 93.3 percent of reductions and 88.1 percent of credits occurred in hours ending 0900 to 2100, and in the first nine months of 2018, 92.3 percent of reductions and 85.4 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, 2017 and 2018

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change
1 through 6	529	1,270	140%	$35,014	$91,078	160%
7	335	1,031	207%	$20,767	$63,448	206%
8	1,212	1,668	38%	$54,407	$102,347	88%
9	1,860	2,093	13%	$61,163	$102,947	68%
10	2,320	2,307	(1%)	$73,002	$102,175	40%
11	2,627	2,441	(7%)	$84,573	$110,527	31%
12	2,858	2,612	(9%)	$96,702	$115,202	19%
13	3,089	2,749	(11%)	$116,212	$122,476	5%
14	3,975	3,418	(14%)	$162,150	$150,398	(7%)
15	4,566	3,477	(24%)	$210,282	$165,814	(21%)
16	4,852	3,538	(27%)	$221,000	$192,885	(13%)
17	4,987	4,039	(19%)	$274,350	$234,293	(15%)
18	5,040	3,928	(22%)	$252,708	$215,010	(15%)
19	4,092	3,013	(26%)	$171,248	$168,495	(2%)
20	3,389	2,790	(18%)	$126,591	$136,566	8%
21	2,354	2,383	1%	$91,568	$120,146	31%
22	773	829	7%	$39,340	$48,018	22%
23 through 24	471	466	(1%)	$11,851	$26,914	127%
Total	49,331	44,054	(11%)	$2,102,927	$2,268,741	8%

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 2017 and 2018. In the first nine months of 2018, 3.5 percent of MWh reductions and 14.6 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

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

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through September, 2017 and 2018

	MWh Reductions			Program Credits		
LMP	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change
$0 to $25	3,154	3,793	20%	$37,399	$65,784	76%
$25 to $50	33,311	26,696	(20%)	$1,030,640	$913,278	(11%)
$50 to $75	7,887	6,132	(22%)	$453,010	$342,065	(24%)
$75 to $100	2,465	3,215	30%	$218,510	$265,908	22%
$100 to $125	1,100	1,438	31%	$120,941	$153,154	27%
$125 to $150	748	1,063	42%	$101,899	$127,410	25%
$150 to $175	462	551	19%	$79,659	$69,708	(12%)
> $175	197	1,571	699%	$60,828	$331,335	445%
Total	49,323	44,459	(10%)	$2,102,887	$2,268,642	8%

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.[30] 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 from April 1, 2012, when Order No. 745 was implemented in PJM, through September 30, 2018.

Table 6-11 Net benefits test threshold prices: April 2012 through September 2018

	Net Benefits Test Threshold Price ($/MWh)						
Month	2012	2013	2014	2015	2016	2017	2018
Jan		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27
Feb		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65
Mar		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50
Apr	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56
May	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52
Jun	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59
Jul	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57
Aug	$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53
Sep	$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23
Oct	$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	
Nov	$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	
Dec	$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	
Average	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.49

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 2018, the highest zonal LMP in PJM was higher than the NBT threshold price 5,392 hours out of 6,551 hours, or 82.3 percent of all hours. Reductions occurred in 3,468 hours, 64.3 percent, of those 5,392 hours in the first nine months of 2018. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2017 through September 30, 2018. There were

30 "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 97 (July 26, 2018) at 146.

6.4 percent of hours with demand response below the NBT threshold price in the first nine months of 2017 and 0.0 percent of hours with demand response below the NBT threshold price in the first nine months of 2018.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2017 and 2018

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2017	2018	2017	2018	Percent Change	2017	2018	Percent Change
Jan	744	744	388	665	71.4%	63.4%	62.9%	(0.5%)
Feb	672	672	414	485	17.1%	37.7%	44.7%	7.1%
Mar	743	743	484	713	47.3%	64.3%	58.3%	(5.9%)
Apr	720	720	407	663	62.9%	72.7%	73.8%	1.0%
May	744	744	445	611	37.3%	76.0%	62.7%	(13.3%)
Jun	720	720	421	503	19.5%	67.5%	64.0%	(3.4%)
Jul	744	744	546	549	0.5%	67.2%	74.0%	6.7%
Aug	744	744	573	560	(2.3%)	55.7%	72.5%	16.8%
Sep	720	720	641	643	0.3%	52.4%	63.9%	11.5%
Oct	744		742			61.2%		
Nov	721		499			59.1%		
Dec	744		509			60.1%		
Total	8,784	6,551	8,192	5,392	(34.2%)	59.8%	64.3%	4.5%

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 and Dominion paid the highest DR charges in the first nine months of 2018.

Table 6-13 Zonal DR charge: January through September, 2018

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$8,097	$1,186	$1,285	$2,112	$1,789	$1,983	$3,197	$5,638	$873	$26,161
AEP	$120,561	$15,321	$33,257	$38,747	$42,364	$24,801	$31,752	$50,786	$8,644	$366,232
APS	$48,552	$6,552	$13,514	$15,101	$15,765	$9,088	$12,154	$19,811	$3,395	$143,932
ATSI	$57,105	$8,625	$17,573	$20,367	$22,984	$13,154	$17,529	$28,408	$4,789	$190,534
BGE	$31,568	$4,497	$8,721	$9,385	$10,481	$6,454	$8,867	$14,557	$2,498	$97,029
ComEd	$62,782	$9,476	$15,824	$23,196	$26,113	$18,968	$26,734	$32,471	$6,498	$222,060
DAY	$15,727	$2,218	$4,647	$5,567	$6,289	$3,466	$4,408	$7,324	$1,191	$50,837
DEOK	$23,915	$2,899	$6,629	$7,909	$9,656	$5,767	$7,289	$11,582	$1,964	$77,610
Dominion	$103,016	$12,383	$26,495	$27,738	$34,552	$20,813	$26,831	$44,184	$7,442	$303,453
DPL	$19,093	$2,543	$3,112	$4,703	$3,675	$3,439	$5,184	$8,947	$1,394	$52,090
DLCO	$11,456	$1,571	$3,335	$4,121	$4,931	$2,795	$3,840	$6,276	$1,075	$39,400
EKPC	$14,563	$1,567	$3,053	$3,422	$3,886	$2,498	$3,281	$5,165	$869	$38,304
JCPL	$19,114	$2,897	$3,073	$5,315	$4,891	$4,678	$7,332	$13,080	$1,991	$62,372
Met-Ed	$14,390	$1,984	$2,647	$3,918	$3,105	$2,528	$3,988	$6,917	$1,048	$40,525
PECO	$36,605	$5,041	$5,544	$10,159	$7,779	$7,117	$11,113	$19,267	$3,056	$105,682
PENELEC	$15,500	$2,438	$4,255	$5,383	$4,944	$2,945	$4,034	$6,747	$1,124	$47,370
Pepco	$29,228	$3,750	$8,347	$8,881	$10,695	$6,269	$8,494	$13,837	$2,370	$91,871
PPL	$39,796	$5,130	$5,853	$10,340	$9,805	$5,874	$7,593	$13,579	$2,332	$100,302
PSEG	$35,936	$5,695	$6,059	$10,477	$7,260	$6,157	$9,725	$15,970	$2,543	$99,823
RECO	$1,144	$184	$208	$10,531	$9,464	$8,311	$12,768	$22,279	$3,480	$68,368
Exports	$25,969	$4,832	$9,278	$362	$389	$336	$502	$888	$134	$42,691
Total	$734,117	$100,789	$182,709	$227,734	$240,817	$157,440	$216,614	$347,713	$58,712	$2,266,645

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in the first nine months of 2018. On a dollar per MWh basis, real-time load and exports in ComEd paid the highest charges for economic demand response in the first nine months of 2018. The highest average zonal monthly per MWh charges for economic demand response occurred in January, when ComEd, DEOK and EKPC paid an average of $0.014/MWh.

Table 6-14 Zonal DR charge per MWh of load and exports: January through September, 2018

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	$0.013	$0.003	$0.004	$0.003	$0.002	$0.002	$0.003	$0.005	$0.001	$0.004
AEP	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.004	$0.001	$0.004
APS	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
ATSI	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.004	$0.001	$0.004
BGE	$0.013	$0.003	$0.003	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
ComEd	$0.014	$0.004	$0.004	$0.003	$0.003	$0.002	$0.003	$0.003	$0.001	$0.004
DAY	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
DEOK	$0.014	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.004	$0.001	$0.004
Dominion	$0.013	$0.003	$0.003	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
DPL	$0.013	$0.003	$0.004	$0.004	$0.003	$0.002	$0.003	$0.005	$0.001	$0.004
DLCO	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
EKPC	$0.014	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
JCPL	$0.013	$0.003	$0.004	$0.003	$0.003	$0.002	$0.003	$0.005	$0.001	$0.004
Met-Ed	$0.013	$0.003	$0.004	$0.003	$0.003	$0.002	$0.003	$0.005	$0.001	$0.004
PECO	$0.013	$0.003	$0.004	$0.004	$0.003	$0.002	$0.003	$0.005	$0.001	$0.004
PENELEC	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.004	$0.001	$0.004
Pepco	$0.013	$0.003	$0.003	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004
PPL	$0.013	$0.003	$0.004	$0.003	$0.002	$0.002	$0.003	$0.004	$0.001	$0.004
PSEG	$0.013	$0.003	$0.004	$0.003	$0.003	$0.002	$0.003	$0.005	$0.001	$0.004
RECO	$0.013	$0.003	$0.004	$0.004	$0.003	$0.002	$0.003	$0.005	$0.001	$0.004
Exports	$0.011	$0.002	$0.003	$0.005	$0.004	$0.002	$0.002	$0.004	$0.001	$0.004
Monthly Average	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.001	$0.004

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges for January 1, 2017, through September 30, 2018. The day-ahead DR charges increased by $113.4 thousand, 16.9 percent, from $671.4 thousand in the first nine months of 2017 to $784.8 thousand in the first nine months of 2018. The real-time DR charges increased $52.4 thousand, 3.7 percent, from $1,431.5 thousand in the first nine months of 2017 to $1,483.9 thousand in the first nine months of 2018.

Table 6-15 Monthly day-ahead and real-time economic DR charge: 2017 through September 2018

	Day-ahead DR Charge			Real-time DR Charge			Per MWh Charge ($/MWh)		
Month	2017	2018	Percent Change	2017	2018	Percent Change	2017	2018	Percent Change
Jan	$35,134	$319,726	810.0%	$311,498	$414,391	33.0%	$0.010	$0.013	31.4%
Feb	$25,562	$23,206	(9.2%)	$16,797	$77,584	361.9%	$0.022	$0.003	(85.9%)
Mar	$70,093	$58,999	(15.8%)	$75,293	$125,482	66.7%	$0.002	$0.004	91.0%
Apr	$87,514	$85,677	(2.1%)	$27,455	$142,057	417.4%	$0.009	$0.004	(57.1%)
May	$75,756	$97,313	28.5%	$251,622	$143,598	(42.9%)	$0.010	$0.004	(64.6%)
Jun	$132,225	$56,538	(57.2%)	$172,812	$101,014	(41.5%)	$0.004	$0.002	(43.6%)
Jul	$100,525	$63,540	(36.8%)	$269,488	$153,191	(43.2%)	$0.063	$0.000	(100.0%)
Aug	$64,713	$54,452	(15.9%)	$135,343	$293,261	116.7%	$0.010	$0.000	(100.0%)
Sep	$79,924	$25,396	(68.2%)	$171,172	$33,316	(80.5%)	$0.014	$0.000	(100.0%)
Oct	$74,161			$131,587			$0.003		
Nov	$23,472			$91,519			$0.001		
Dec	$104,711			$116,295			$0.002		
Total	$873,791	$784,847	(10.2%)	$1,770,882	$1,483,894	(16.2%)	$0.013	$0.003	(73.6%)

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 for the 2020/2021 Delivery Year onward 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.[31] With the implementation of Capacity Performance, a performance assessment hour (PAH) occurs when emergency or pre-emergency is dispatched. PJM effectively eliminated the difference between pre-emergency and emergency by making both trigger a PAH. 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.[32]

31 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.

32 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).

The ownership of demand resources was moderately concentrated based on committed MW in the capacity market in the 2017/2018 Delivery Year. The HHI for demand resources was 1433 for the 2017/2018 Delivery Year and 1922 for the 2018/2019 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all registered demand resources. In the 2018/2019 Delivery Year, the four largest companies contributed 77.9 percent of all registered demand resources.

Table 6-16 shows the HHI value for LDAs by delivery year. The HHI values are calculated by the cleared UCAP MW in each delivery year for demand resources. 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.

Table 6-16 HHI value for LDAs by delivery year: 2017/2018 and 2018/2019 Delivery Years[33]

Delivery Year	LDA	UCAP MW	HHI Value	HHI Concentration
2017/2018	RTO	4,018.0	2593	High
	MAAC	655.7	1914	High
	EMAAC	1,057.3	2093	High
	DPL-SOUTH	86.3	3145	High
	PSEG	236.9	1409	Moderate
	PS-NORTH	151.5	2043	High
	PEPCO	608.4	3726	High
	ATSI	720.8	3615	High
	ATSI-CLEVELAND	282.4	4927	High
	COMED	1,470.8	3353	High
	BGE	790.7	5309	High
	PPL	650.5	2167	High
2018/2019	RTO	4,044.7	2199	High
	MAAC	712.1	2144	High
	EMAAC	1,206	2,028	High
	PSEG	250	2,298	High
	PS-NORTH	133	3,085	High
	PEPCO	523	5,027	High
	ATSI	609	3,413	High
	ATSI-CLEVELAND	268	3,514	High
	COMED	1,877	3,183	High
	BGE	660	5,424	High
	PPL	716	1,862	High

33 The RTO LDA refers to the rest of RTO.

Table 6-17 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2018. Capacity market revenue increased in the first nine months of 2018 by $60.9 million, 16.7 percent, from $365.4 million in the first nine months of 2017 to $426.3 million in the first nine months of 2018.

Table 6-17 Zonal monthly capacity revenue: 2018

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$490,121	$442,690	$490,121	$474,310	$490,121	$1,028,760	$1,063,052	$1,063,052	$1,028,760	$6,570,984
AEP, EKPC	$6,277,982	$5,670,436	$6,277,982	$6,075,467	$6,277,982	$7,126,198	$7,363,738	$7,363,738	$7,126,198	$59,559,720
APS	$3,635,631	$3,283,796	$3,635,631	$3,518,353	$3,635,631	$4,488,613	$4,638,234	$4,638,234	$4,488,613	$35,962,736
ATSI	$4,068,474	$3,674,751	$4,068,474	$3,937,233	$4,068,474	$4,117,257	$4,254,499	$4,254,499	$4,117,257	$36,560,916
BGE	$2,978,415	$2,690,181	$2,978,415	$2,882,337	$2,978,415	$1,424,334	$1,471,812	$1,471,812	$1,424,334	$20,300,055
ComEd	$5,931,017	$5,357,047	$5,931,017	$5,739,694	$5,931,017	$11,384,156	$11,763,628	$11,763,628	$11,384,156	$75,185,359
DAY	$757,213	$683,934	$757,213	$732,787	$757,213	$1,047,740	$1,082,665	$1,082,665	$1,047,740	$7,949,170
DEOK	$680,554	$614,694	$680,554	$658,601	$680,554	$963,997	$996,130	$996,130	$963,997	$7,235,213
DLCO	$4,444,838	$4,014,692	$4,444,838	$4,301,456	$4,444,838	$3,717,864	$3,841,793	$3,841,793	$3,717,864	$36,769,977
Dominion	$1,493,172	$1,348,671	$1,493,172	$1,445,005	$1,493,172	$2,671,780	$2,760,840	$2,760,840	$2,671,780	$18,138,432
DPL	$664,561	$600,248	$664,561	$643,123	$664,561	$1,190,255	$1,229,930	$1,229,930	$1,190,254	$8,077,422
JCPL	$616,455	$556,798	$616,455	$596,570	$616,455	$1,281,410	$1,324,124	$1,324,124	$1,281,410	$8,213,802
Met-Ed	$1,122,182	$1,013,583	$1,122,182	$1,085,982	$1,122,182	$1,478,427	$1,527,708	$1,527,708	$1,478,427	$11,478,382
PECO	$1,860,312	$1,680,282	$1,860,312	$1,800,302	$1,860,312	$3,234,300	$3,342,110	$3,342,110	$3,234,300	$22,214,342
PENELEC	$1,330,187	$1,201,460	$1,330,187	$1,287,278	$1,330,187	$1,753,015	$1,811,449	$1,811,449	$1,753,015	$13,608,228
Pepco	$2,320,851	$2,096,252	$2,320,851	$2,245,985	$2,320,851	$780,853	$806,881	$806,881	$780,853	$14,480,257
PPL	$2,491,224	$2,250,138	$2,491,224	$2,410,862	$2,491,224	$2,240,289	$2,314,965	$2,314,965	$2,240,289	$21,245,183
PSEG	$2,576,169	$2,326,862	$2,576,169	$2,493,066	$2,576,169	$2,440,539	$2,521,890	$2,521,890	$2,440,539	$22,473,291
RECO	$12,475	$11,267	$12,475	$12,072	$12,475	$47,392	$48,971	$48,971	$47,392	$253,490
Total	$43,751,832	$39,517,784	$43,751,832	$42,340,483	$43,751,832	$52,417,179	$54,164,419	$54,164,419	$52,417,179	$426,276,960

Table 6-18 Energy efficiency resources (MW): June 1, 2012 to June 1, 2018

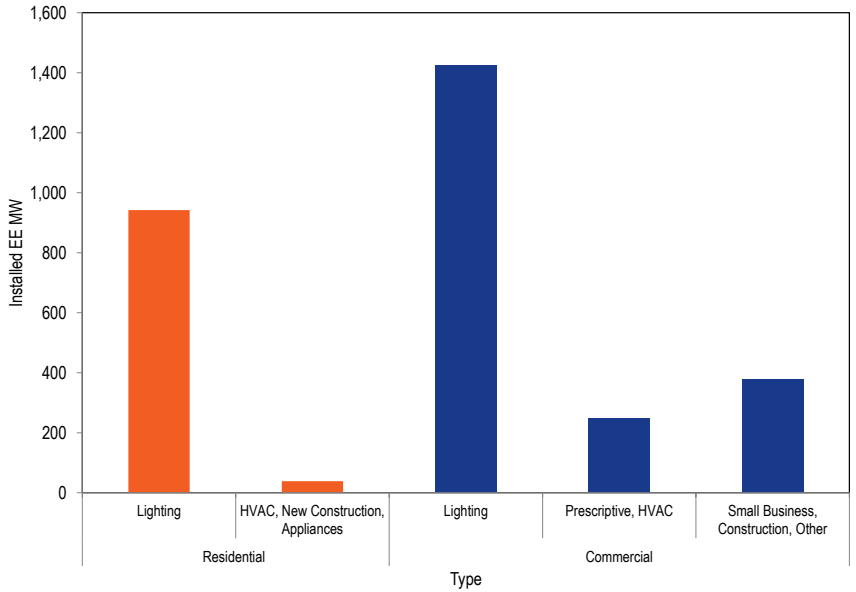
	UCAP (MW) RPM Commitments
01-Jun-12	631.2
01-Jun-13	1,024.8
01-Jun-14	1,282.4
01-Jun-15	1,525.5
01-Jun-16	1,784.3
01-Jun-17	2,117.9
01-Jun-18	2,545.1

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2012/2013 through 2017/2018 delivery years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[34] Only Kentucky has been authorized by the Commission. 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.[35]

Figure 6-3 shows the amount of installed EE MW in PJM by technology for the 2017/2018 Delivery Year. An installed EE resource may participate as a capacity resource for up to a maximum of four consecutive delivery years.[36] Energy efficiency MW procured by an incentive program for lighting, HVAC or appliances are listed as prescriptive MW. 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. The calculated MW are bid into PJM's Capacity Market as EE. The installed EE resources for the 2017/2018 Delivery Year include any installed EE resource between June 1, 2013 and May 31, 2017.

34 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).
35 *2018 Quarterly State of the Market Report for PJM: January through September*, Volume 2, Section 5: Capacity Market, Table 5-13.
36 PJM. "Manual 18: Capacity Market," Rev. 40 (Feb. 22, 2018), p. 80.

Figure 6-3 Installed energy efficiency MW by type: 2017/2018 Delivery Year



FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[37] 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.[38] 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.[39] 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. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-19 shows the amount of nominated MW and locations by product type and lead time for the 2017/2018 Delivery Year. PJM approved 2,682 locations, or 17.1 percent of all locations, which have 3,681.5 nominated MW, or 40.2 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2017/2018 Delivery Year.

37 See 147 FERC ¶ 61,103 (2014).
38 See PJM Interconnection, L.L.C., Docket No. ER14-135-000 (October 20, 2014).
39 See "PJM Manual 18: Capacity Market," Rev. 40 (Feb. 22, 2018) at 62.

Table 6-19 Nominated MW and locations by product type and lead time: 2017/2018 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	1,410.8	3,137.9	418.0	280.6	5,247.3	51.1	160.4	7.5	7.0	225.9	5,473.2
Short Lead (60 Minutes)	129.5	140.8	46.0	79.6	395.9	3.0	13.2	0.0	0.0	16.1	412.0
Long Lead (120 Minutes)	822.6	1,701.2	476.6	156.4	3,156.7	18.8	43.1	44.7	6.2	112.8	3,269.6
Total	2,362.9	4,979.8	940.6	516.6	8,799.9	72.8	216.7	52.2	13.2	354.8	9,154.7
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	3,712	7,587	1,205	126	12,630	84	269	8	23	384	13,014
Short Lead (60 Minutes)	97	155	47	6	305	17	6	0	0	23	328
Long Lead (120 Minutes)	380	617	1,288	15	2,300	12	35	6	1	54	2,354
Total	4,189	8,359	2,540	147	15,235	113	310	14	24	461	15,696

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 2,627 locations, or 19.1 percent of all locations, which have 3,943.1 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.

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	222.6	18.9	241.7	5,045.0
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	2,665.4	527.7	3,315.9	0.0	0.0	144.2	0.0	144.2	3,460.1
Total	457.8	6.8	7,212.7	898.4	8,575.7	0.2	0.0	393.3	18.9	412.4	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	9,900	686	10,755	4	0	330	45	379	11,134
Short Lead (60 Minutes)	12	0	280	30	322	0	0	22	0	22	344
Long Lead (120 Minutes)	33	0	1,802	374	2,209	0	0	74	0	74	2,283
Total	212	2	11,982	1,090	13,286	4	0	426	45	475	13,761

There are three different ways to measure load reductions of demand resources. The Firm Service Level (FSL) method measures the difference between a customer's peak load contribution (PLC) and real-time load, multiplied by the loss factor (LF). 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.[40] The implementation of a Winter Peak Load (WPL), effective for the 2017/2018 Delivery Year, measures capacity compliance during winter months from the WPL rather than the PLC. 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.[41] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[42] 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 Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely trigger load reductions. DLC customers were not required to submit meter data to calculate load reductions. The direct load control method is no longer an eligible reduction method after May 31, 2016.[43] The FSL and GLD equations for calculating load reductions are:

FSL Reduction = PLC – (Load · LF)

GLD Reduction = Minimum of {(comparison load – Load) · LF; PLC – (Load · LF)}

Table 6-21 shows the MW registered by measurement and verification method and by technology type for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, 99.4 percent use the FSL method and 0.6 percent use the GLD measurement and verification method.

Table 6-21 Reduction MW by each demand response method: 2017/2018 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	1,266.4	2,973.7	237.4	769.6	3,726.2	78.7	52.0	9,104.0	99.4%
Guaranteed Load Drop	8.9	19.4	1.6	3.6	17.1	0.1	0.0	50.7	0.6%
Total	1,275.4	2,993.1	239.0	773.2	3,743.2	78.8	52.0	9,154.7	100.0%
Percent by method	13.9%	32.7%	2.6%	8.4%	40.9%	0.9%	0.6%	100.0%	

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.

40 135 FERC ¶ 61,212.
41 OATT Attachment DD.5.11.
42 OATT Attachment M-2.
43 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb 22, 2018) at 63.

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	Other, Batteries or Plug Load MW	Total	Percent by Type
Firm Service Level	1,147.2	2,688.8	210.1	622.1	4,134.4	116.4	41.6	8,960.7	99.7%
Guaranteed Load Drop	1.4	9.0	0.0	0.6	16.4	0.1	0.0	27.4	0.3%
Total	1,148.6	2,697.8	210.1	622.7	4,150.8	116.5	41.6	8,988.1	100.0%
Percent by method	12.8%	30.0%	2.3%	6.9%	46.2%	1.3%	0.5%	100.0%	

Table 6-23 shows the fuel type used in the onsite generators for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, there are 354.5 MW, 27.8 percent, registered with an onsite generator in the emergency program. Of the 13.9 percent of nominated emergency and pre-emergency demand response MW identified as using onsite generation for the 2017/2018 Delivery Year, 74.5 percent of MW are diesel, 24.4 percent of MW are natural gas and 1.1 percent of MW are gasoline, kerosene, oil, propane or waste products.

Table 6-23 Onsite generation fuel type (MW): 2017/2018 Delivery Year

	2017/2018	
Fuel Type	MW	Percent
Diesel	950.1	74.5%
Natural Gas	311.3	24.4%
Gasoline, Kerosene, Oil, Propane, Waste Products	13.9	1.1%
Total	1,275.4	100.0%

Table 6-24 shows the fuel type used in the onsite generators for the 2018/2019 Delivery Year. For the 2018/2019 Delivery Year, there are 354.5 MW, 27.8 percent, registered with an onsite generator in the emergency program. Of the 12.8 percent of nominated emergency and pre-emergency demand response MW identified as using onsite generation for the 2018/2019 Delivery Year, 84.3 percent of MW are diesel and 15.7 percent of MW are natural gas, gasoline, oil, propane or waste products.

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

	2018/2019	
Fuel Type	MW	Percent
Diesel	968.8	84.3%
Natural Gas, Gasoline, Oil, Propane, Waste Products	179.8	15.7%
Total	1,148.6	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Table 6-25 shows the demand response cleared UCAP MW for PJM by delivery year. Total demand response cleared in PJM decreased by 1,284.6 MW, or 9.7 percent, from 13,265.3 MW in the 2016/2017 Delivery Year to 11,980.7 MW in the 2017/2018 Delivery Year. The DR percent of capacity decreased by 0.8 percent, from 5.1 percent in the 2016/2017 Delivery Year to 4.3 percent in the 2017/2018 Delivery Year.

Table 6-25 Demand response cleared MW UCAP for PJM: 2011/2012 through 2017/2018 Delivery Year

Delivery Year	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
2011/2012	1,826.6	1.4%
2012/2013	8,740.9	6.2%
2013/2014	10,779.6	6.7%
2014/2015	14,943.0	9.3%
2015/2016	15,453.7	8.9%
2016/2017	13,265.3	5.1%
2017/2018	11,980.7	4.3%

Subzonal dispatch of emergency demand resources was mandatory for the 2014/2015 Delivery Year, but only if the subzone was defined by PJM no later than the day before the dispatch.[44] Capacity performance demand resources do not need to have a subzone defined by PJM before mandatory dispatch.[45] There are thirteen dispatchable subzones in PJM effective April 26, 2017: 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.[46] Effective 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance, which does not require defined subzones for dispatch. PJM can remove a defined 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.[47] 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 17 closed loop interface definitions, 11 (65 percent) were created for the purpose of allowing emergency DR to set price.[48]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance.

Limited, extended summer and annual demand resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance no less than hourly to accurately report reductions during demand response events. The current rules use the average reduction for the duration of an event. The average duration 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

44 OATT Attachment DD, Section 11.
45 OATT Attachment DD, Section 10A.
46 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed August 1, 2018).
47 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).
48 *See the 2017 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.

PJM system. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.[49]

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.[50] 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).[51] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now 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 hour (PAH) for CP compliance.

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency Action Area (EAA).[52] [53] 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.[54] 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.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance

49 "PJM Manual 18: Capacity Market," Rev. 40 (Feb. 22, 2018) at 148.

50 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>.

51 OATT § 1 (Performance Assessment Hour).

52 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.

53 PJM. "Manual 18: Capacity Market," Rev. 40 (Feb. 22, 2018), p. 185.

54 See "PJM Manual 18: Capacity Market," Rev. 40 (Feb. 22, 2018) at 166.

purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[55] 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.[56] The MMU recommends the RRMSE test be required for all demand resources with a CBL. The correct CBL may more accurately measure reductions for demand resources.

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.[57]

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.

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

55 OA Schedule 1 § 8.9.
56 157 FERC ¶ 61,067 (2016).
57 OA Schedule 1 § 8.9.

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."[58] 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.[59] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[60] 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. 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 6-26 shows the test penalties by delivery year by product type for the 2015/2016 Delivery Year through the 2017/2018 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.

58 OA Schedule 1 § 8.2.

59 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>.

60 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. 40 (Feb. 22, 2018), p. 69.

Table 6-26 Test penalties by delivery year by product type: 2015/2016 through 2017/2018

	2015/2016			2016/2017			2017/2018		
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
Limited	96.4	$165.35	$5,836,255	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665
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									
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

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.[61] 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. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The scarcity pricing rules allow a maximum DR energy price of $1,849 per MWh for the 2017/2018 Delivery Year and the 2018/2019 Delivery Year.[62] [63] Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only. "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[64] Demand response resources register as capacity only, energy only or full program option. The full program option includes 98.8 percent of nominated MW for the 2018/2019 Delivery Year. Demand resources not registered as capacity only should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[65]

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.[66]

Table 6-27 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2017/2018 Delivery Year. The majority of participants, 73.4 percent of locations and 65.7 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 2017/2018 Delivery Year, 4.8 percent of location and 4.0 percent of nominated MW have a dispatch price between $0 and $999 per MWh, and 95.2 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 $999 to $1,100 per MWh strike prices had the highest average at $239.13 per location and $937.37 per nominated MW.

61 *Id.*
62 139 FERC ¶ 61,057 (2012).
63 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.
64 161 FERC ¶ 61,153 (2017).
65 OATT Attachment K Appendix Section 1.10.1A Day-ahead Energy Market Scheduling (d) (x).
66 "PJM Manual 15: Cost Development Guidelines," Rev. 29 (May 15, 2017) at 59.

Table 6-27 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2017/2018 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	459	2.9%	53.9	0.6%	$0.00	$0.00
$1-$999	291	1.9%	305.4	3.4%	$77.61	$73.94
$999-$1,100	1,288	8.3%	328.6	3.7%	$239.13	$937.37
$1,100-$1,275	1,789	11.5%	2,925.9	32.5%	$94.68	$57.89
$1,275-$1,550	315	2.0%	283.5	3.2%	$57.43	$63.81
$1,550-$1,849	11,437	73.4%	5,093.4	56.7%	$44.54	$100.01
Total	15,579	100.0%	8,990.8	100.0%	$65.95	$114.28

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, 78.4 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, 2.8 percent of locations and 7.2 percent of nominated MW have a dispatch price between $0 and $1,100 per MWh, and 97.2 percent of locations and 92.8 percent of nominated MW have a dispatch price above $1,100 per MWh. The shutdown cost of resources with $0 to $1,100 per MWh strike prices had the highest average at $213.51 per location and $397.58 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-$1,100	383	2.8%	637.5	7.2%	$213.51	$397.58
$1,100-$1,275	2,235	16.4%	3,069.9	34.6%	$140.16	$102.05
$1,275-$1,550	325	2.4%	380.6	4.3%	$56.77	$48.48
$1,550-$1,849	10,695	78.4%	4,776.1	53.9%	$52.95	$118.57
Total	13,638	100.0%	8,864.1	100.0%	$71.84	$110.54

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.[67] For example, Table 6-23 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2017/2018 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.[68] [69] 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.[70] Aggregation to a single node is as geographically broad as technically feasible. Allowing DER aggregation across nodes 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.

67 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).

68 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>.

69 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).

70 162 FERC ¶ 32,718 at P 139 (2016).