# 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 Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[1] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's action on petitions for writ of certiorari filed by the Solicitor General, on behalf of the FERC (January 15, 2015) and by EnerNOC, Inc.; Viridity Energy, Inc.; and EnergyConnect, Inc. (January 15, 2015).

  FirstEnergy filed an amended complaint on September 22, 2014, that seeks to extend *EPSA v. FERC* to the PJM capacity markets, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of supply effective May 23, 2014, and require a rerun of the 2017/2018 Base Residual Auction.[2]

  PJM filed tariff revisions on January 14, 2015, intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of *EPSA v. FERC* and PJM's pending capacity performance proposal.[3]

- **Demand Response Activity.** Demand response is split into two main categories; economic and emergency. Emergency program revenue includes both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs. In 2014, capacity market revenue increased by $194.5 million, or 44.4 percent, from $438.2 million in 2013 to $632.8 million in 2014.[4] Emergency energy revenue increased by $6.2 million, from $36.7 million in 2013 to $43.0 million in 2014. Economic program revenue is energy revenue only. Economic program credits increased by $8.6 million, from $8.7 million in 2013 to $17.7 million in 2014, a 103 percent increase.[5] Due to the cold winter, economic DR credits increased 1,075 percent in the first three months of 2014. In contrast, economic DR credits decreased by 9.79 percent, from $1.3 million in the fourth quarter of 2013 to $1.2 million in the fourth quarter of 2014. Not all DR activities in the fourth quarter of 2014 have been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[6]

- **Demand Response Market Concentration.** Economic demand response was highly concentrated in 2013 and 2014. The HHI for economic demand response reductions decreased from 8194 in 2013 to 7721 in 2014. Emergency demand response was moderately concentrated in 2013 and 2014. The HHI for emergency demand response registrations increased from 1529 in 2013 to 1760 in 2014. In 2014, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** In the 2013/2014 Delivery Year PJM continued to dispatch demand resources on a zonal basis with the option

1 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied; see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

2 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.

3 See PJM filing, Docket No. ER15-852-000.

4 The total credits and MWh numbers for demand resources were calculated as of March 4, 2015 and may change as a result of continued PJM billing updates.

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

6 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

of voluntary subzonal dispatch. Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

- Emergency Event Day Analysis. PJM's calculations overstate participants' compliance during emergency load management events. In PJM's calculations, load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards showing apparent higher compliance since poorly performing demand resources are not used in the compliance calculation. Considering all reported positive and negative values, the observed average load reduction of the eight events in 2014 should have been 2,198.6 MW, rather than the 2,840.9 MW calculated using PJM's method. The observed compliance is 29.2 percent rather than PJM's calculated 37.7 percent. This does not include locations that did not report their load during the emergency event days. All locations should be required to report their load.

## Recommendations

- The MMU recommends that, if demand response remains in the PJM market, there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2013. Status: Not Adopted.[7])
- The MMU recommends that, if demand response remains in the PJM market, the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[8] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[9] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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: Adopted in full, Q1, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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, if demand response remains in the PJM market, 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.[10] (Priority: Medium. First reported 2013. Status: Not adopted.)

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.

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

9 *Id* at 1.

10 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 February 17, 2015) 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, if demand response remains in the PJM market, demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted in full, Q2, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, 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 2013. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. New recommendation. Status: Not adopted.)

## Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time and will have the ability to receive the direct benefits or costs of changes in real time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. 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.

With exception of large wholesale customers in some areas, most customers in PJM are not on retail rates that directly expose them to the wholesale price of energy or capacity. As a result, most customers in PJM do not have the direct ability to see, respond to or benefit from a response to price signals in PJM's markets. PJM's demand side programs are generally designed to allow customers (or their intermediaries in the form of load serving entities (LSEs) or curtailment service providers (CSPs)) to either directly, or through intermediaries, be paid as if they were directly paying the wholesale price of energy and capacity and avoiding those prices when reducing load. PJM's demand side programs are designed to provide direct incentives for load resources to respond, via load reductions, to wholesale market price signals and/or system emergency events.

If retail markets reflected hourly wholesale locational prices and customers or their intermediaries received direct savings associated with reducing consumption in response to real time prices, there would not be a need for a PJM economic load response program, or for extensive measurement and verification protocols. In the transition to that point, however, as long as there are demand side programs, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

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. That is a prerequisite to a functional market design.

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 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 and not be limited to a small number of hours.

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.

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.

As a preferred alternative, demand response would be on the demand side of the capacity market rather than on the supply side. Rather than complex demand side 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.

The long term appropriate end state for demand side 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 suggested by the Market Monitor.

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with any Supreme Court decision on EPSA as it does not require FERC to have jurisdiction over the demand side. This approach will allow the Commission to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets.

## PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs.[11] Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to both emergency and economic programs. Demand resource is used here to refer to both resources participating in the capacity market and resources participating in the energy market. In both the economic and emergency programs, CSPs are companies that seek to sign up end-use customers, participants, 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 compensates their participants. Only CSPs are eligible to participate in the PJM Demand Response program, but a participant can register as a PJM special member and become a CSP without any additional cost of entry.

11 Throughout this document, emergency demand response refers to both emergency and pre emergency demand response.

Table 6-1 Overview of demand response programs

| | Emergency Load Response Program | | | Economic Load Response Program |
|---|---|---|---|---|
| | Load Management (LM) | | | |
| Market | Capacity Only | Capacity and Energy | Energy Only | Energy Only |
| Capacity Market | DR cleared in RPM | DR cleared in RPM | Not included in RPM | Not included in RPM |
| Dispatch Requirement | Mandatory Curtailment | Mandatory Curtailment | Voluntary Curtailment | Dispatched Curtailment |
| Penalties | RPM event or test compliance penalties | RPM event or test compliance penalties | NA | NA |
| Capacity Payments | Capacity payments based on RPM clearing price | Capacity payments based on RPM price | NA | NA |
| Energy Payments | No energy payment. | Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments. | Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments. | Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. |

In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[12] The court found Order No. 745 arbitrary and capricious on its merits.[13] More importantly, the court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market — a matter exclusively within state control."[14] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's action on petitions for writ of certiorari. Petitions were filed by the Solicitor General, on behalf of the FERC (January 15, 2015) and by EnerNOC, Inc.; Viridity Energy, Inc.; and EnergyConnect, Inc. (January 15, 2015).

FirstEnergy filed an amended complaint on September 22, 2014, that seeks to extend the finding in *EPSA v. FERC* to the PJM capacity market, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of capacity supply effective May 23, 2014.[15] The complaint also seeks to void the results of the 2017/2018 Base Residual Auction conducted in May 2014 and to rerun the auction excluding Demand Resources. The Market Monitor issued a report on July 10, 2014, analyzing the worst case effects in the event that such relief were granted.[16] The report concludes that "should a legal or policy decision be made to eliminate Demand Resources from its current participation as supply in the PJM capacity market, PJM markets could adapt."[17] The proceeding is pending before the Commission.

PJM filed tariff revisions on January 14, 2015, intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of *EPSA v. FERC* and PJM's pending capacity performance proposal.[18] The Market Monitor filed comments criticizing PJM's filing as overly complicated and unnecessary.[19]

EPSA presents an opportunity to reform the rules for demand response to make them consistent with the functioning of an efficient and competitive market. The current rules for demand response have evolved to create a negative impact on market efficiency and pose obstacles to the growth of an effective demand component to the market. This negative impact is not the result of demand side resources which are an invaluable part of the markets but is a result of current PJM rules. These flaws have been well documented, and some are

12 Electric Power Supply Association v. FERC, No. 11-1486.
13 *Id.*, slip. op. at 14.
14 *Id.*
15 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
16 See Monitoring Analytics, LLC, The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses, which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf*>.
17 *Id.* at 10.
18 See PJM filing, Docket No. ER15-852-000.
19 See Comments of the Independent Market Monitor for PJM, ER15-852-000 (February 13, 2015).

the subject of pending litigation at the Commission.[20] Now is an appropriate time for decisive steps away from the flawed approach of treating demand as a form of supply and treating demand response as changes in demand.

## 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 benefit test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charge for wholesale power already included in customers' tariff rates. Annual economic program credits in 2014 were the highest in the last five years, but there were fewer settlements submitted and fewer active participants in 2014 than in 2013.

Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2008 through 2014. Since the implementation of the RPM capacity market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[21]

20 The Market Monitor has documented in numerous reports the price suppressing effects and market design flaws attributable to the current treatment of Demand Resources in the PJM Capacity Market, including:

- The failure to require performance from Demand Resources that is comparable to the performance provided by Generation Capacity Resources and that would therefore make Demand Resources substitutes for Generation Resources while providing substantially the same compensation to both. See, e.g., Monitoring Analytics, LLC, *2013 State of the Market Report for PJM* (March 13, 2013) ("2013 SOM") at 197, 203; see also, Monitoring Analytics, LLC, *Analysis of the 2016/2017 RPM Base Residual Auction* (April 18, 2014) at 3, 35-27 ("2016/2017 BRA Report"), which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf*>.
- The failure to remove inferior Demand Resource products from the capacity markets which cannot, by definition of the products, be substitutes for Generation Resources and the failure to require demand resource products to respond year round during any hour.
- The failure to eliminate the 2.5 shift in the demand curve used in RPM Base Residual Actions. See, e.g., 2013 SOM at 157, 160; 2016/2017 BRA Report at 4-5.
- The failure to require Demand Resources to make physical offers. See, e.g., 2013 SOM at 160, 171-172; Monitoring Analytics, LLC, Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 (September 13, 2013), which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf*>; Comments of the Independent Market Monitor for PJM, Docket No. ER14-1461 (April 1, 2014).
- The failure to require Demand Resources to make daily offers into the Day-Ahead Energy Market as required of Generation Capacity Resources. See, e.g., 2013 SOM at 197, 203; Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, Docket No. EL14-20 (January 27, 2014).
- The failure to apply a uniform system offer cap to Demand Resources and Generation Capacity Resources. Id.
- The failure to develop measurement and verification rules sufficient to ensure that Demand Resources do not consume capacity when it is needed by those who pay for it. See, e.g., 2013 SOM at 197-198, 210; Comments of the Independent Market Monitor for PJM, Docket No. ER14-822 (January 1, 2014).

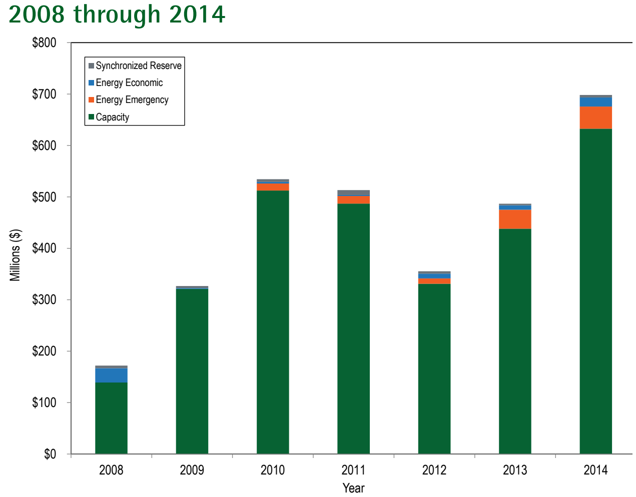
21 This includes both capacity market revenue and emergency energy revenue for capacity resources.

In 2014, emergency revenue, which includes capacity and emergency energy revenue, accounted for 96.8 percent of all revenue received by demand response providers, credits from the economic program were 2.5 percent and revenue from synchronized reserve was 0.7 percent.

Total emergency revenue increased by $200.8 million, or 42.3 percent, from $475.0 million in 2013 to $675.7 in 2014. Of the total emergency revenue, capacity market revenue increased by $194.5 million, or 44.4 percent, from $438.2 million in 2013 to $632.8 million in 2014, due to higher clearing prices and volumes in the capacity market for the 2013/2014 and 2014/2015 delivery years. The weighted average RPM price increased 23.1 percent from $99.39 per MW-day to $122.32 per MW-day.[22] Of the total emergency revenue, emergency energy revenue to demand response that sold capacity increased by $6.2 million from $36.7 million in 2013, to $43.0 million in 2014.

Total credits under the economic program increased by $9.0 million from $8.7 million in 2013 to $17.7 million in 2014, a 103.2 percent increase.

### Figure 6-1 Demand response revenue by market: 2008 through 2014




## Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through December 2014. Registration is a prerequisite for CSPs

22 *2014 State of the Market Report for PJM*, Section 5: Capacity, Table 5-13.

to participate in the economic program. The average number of registrations decreased and the average registered MW increased in 2014. The average number of registrations decreased by 68 from 1,134 in 2013 to 1,066 in 2014. The average monthly registered MW for 2014 increased by 441 MW, or 18.75 percent, from 2,352 MW in 2013 to 2,793 MW in 2014.

Economic demand response was highly concentrated in 2013 and 2014. The HHI for demand response reductions decreased 473 points, from 8194 in 2013 to 7721 in 2014.[23]

There is some overlap between economic registrations and emergency capacity registrations. There were 309 registrations and 1,852 nominated MW in the emergency program that were also in the economic program for 2014.

The registered MW in the economic load response program are not a good measure of the amount of MW available for dispatch in the energy market. Economic resources can dispatch more, less or the amount of MW registered in the program.

Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for January 2010 through December 2014. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW. The annual maximum is the sum of each registration's annual noncoincident peak dispatched MW. This annual aggregated maximum dispatched MW for all economic demand response registered resources in 2014 increased by 253 MW, from 1,486 MW in 2013 to 1,739 MW in 2014.[24] The dispatch reflected the demand conditions in 2014 compared to prior years. For example, January through March of 2014 had significantly more dispatched MW than January through March in each of the last four years.

### Table 6-3 Maximum economic MW dispatched by registration per month: 2010 through 2014

| | Maximum Dispatched MW by Registration | | | | |
|---|---|---|---|---|---|
| Month | 2010 | 2011 | 2012 | 2013 | 2014 |
| Jan | 233 | 243 | 104 | 193 | 446 |
| Feb | 121 | 190 | 101 | 119 | 307 |
| Mar | 115 | 153 | 72 | 127 | 369 |
| Apr | 111 | 80 | 108 | 133 | 146 |
| May | 172 | 98 | 143 | 192 | 151 |
| Jun | 209 | 561 | 944 | 433 | 483 |
| Jul | 999 | 561 | 1,641 | 1,088 | 665 |
| Aug | 794 | 161 | 980 | 497 | 357 |
| Sep | 276 | 84 | 451 | 530 | 795 |
| Oct | 118 | 81 | 242 | 168 | 214 |
| Nov | 111 | 86 | 165 | 155 | 165 |
| Dec | 41 | 88 | 99 | 168 | 155 |
| Annual | 1,209 | 841 | 1,956 | 1,486 | 1,739 |

All demand response energy payments are uplift rather than market payments. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[25]

### Table 6-2 Economic program registrations on the last day of the month: January, 2010 through December, 2014

| | 2010 | | 2011 | | 2012 | | 2013 | | 2014 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Registrations | Registered MW | Registrations | Registered MW | Registrations | Registered MW | Registrations | Registered MW | Registrations | Registered MW |
| Jan | 1,841 | 2,623 | 1,609 | 2,432 | 1,993 | 2,385 | 841 | 2,314 | 1,180 | 2,331 |
| Feb | 1,842 | 2,624 | 1,612 | 2,435 | 1,995 | 2,384 | 843 | 2,327 | 1,174 | 2,336 |
| Mar | 1,845 | 2,623 | 1,612 | 2,519 | 1,996 | 2,356 | 788 | 2,284 | 1,185 | 2,698 |
| Apr | 1,849 | 2,587 | 1,611 | 2,534 | 189 | 1,318 | 970 | 2,346 | 1,194 | 2,832 |
| May | 1,875 | 2,819 | 1,687 | 3,166 | 371 | 1,669 | 1,375 | 2,414 | 745 | 2,516 |
| Jun | 813 | 1,608 | 1,143 | 1,912 | 803 | 2,347 | 1,302 | 2,144 | 928 | 2,949 |
| Jul | 1,192 | 2,159 | 1,228 | 2,062 | 942 | 2,323 | 1,315 | 2,443 | 1,036 | 3,011 |
| Aug | 1,616 | 2,398 | 1,987 | 2,194 | 1,013 | 2,373 | 1,299 | 2,527 | 1,080 | 3,039 |
| Sep | 1,609 | 2,447 | 1,962 | 2,183 | 1,052 | 2,421 | 1,280 | 2,475 | 1,077 | 2,925 |
| Oct | 1,606 | 2,444 | 1,954 | 2,179 | 828 | 2,269 | 1,210 | 2,335 | 1,060 | 2,948 |
| Nov | 1,605 | 2,444 | 1,988 | 2,255 | 824 | 2,267 | 1,192 | 2,307 | 1,063 | 3,000 |
| Dec | 1,598 | 2,439 | 1,992 | 2,259 | 846 | 2,283 | 1,192 | 2,311 | 1,071 | 2,929 |
| Avg. | 1,608 | 2,435 | 1,699 | 2,344 | 1,071 | 2,200 | 1,134 | 2,352 | 1,066 | 2,793 |

23 For more information, see Table 6-8.

24 As a result of the 60 day data lag from event date to settlement, not all settlements for December 2014 are incorporated in this report.

25 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by $56.07 per MWh, or 86.2 percent, from $65.03 per MWh in 2013 to $121.10 per MWh dispatched in 2014. The average real-time load weighted PJM LMP increased by $14.48 per MWh, from $38.66 per MWh during 2013 to $53.14 per MWh during 2014. Curtailed energy for the economic program was 146,194 MWh in 2014 and the total payments were $17,704,862. Credits paid for economic DR in 2014 increased by $8,992,988 or 103 percent, compared to 2013.

### Table 6-4 Credits paid to the PJM economic program participants: 2010 through 2014

| Year | Total MWh | Total Credits | $/MWh |
|---|---|---|---|
| 2010 | 72,757 | $4,728,660 | $64.99 |
| 2011 | 17,398 | $2,052,996 | $118.00 |
| 2012 | 145,019 | $9,284,118 | $64.02 |
| 2013 | 133,963 | $8,711,873 | $65.03 |
| 2014 | 146,194 | $17,704,862 | $121.10 |

Economic demand response resources that are dispatched in both the economic and emergency programs at the same time are settled under emergency rules. For example, assume a demand resource has an economic strike price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource was 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 of the economic strike price of $100 per MWh. The rationale for this rule is not clear. All other resources that clear in the day-ahead market are financially firm at that clearing price.

Figure 6-2 shows monthly economic demand response credits and MWh, for 2010 through 2014. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The extreme weather conditions in January through March, 2014 resulted in higher prices which resulted in higher credits. The January 2014 economic credits were more than twice the previous monthly maximum from July 2012.

### Figure 6-2 Economic program credits and MWh by month: 2010 through 2014

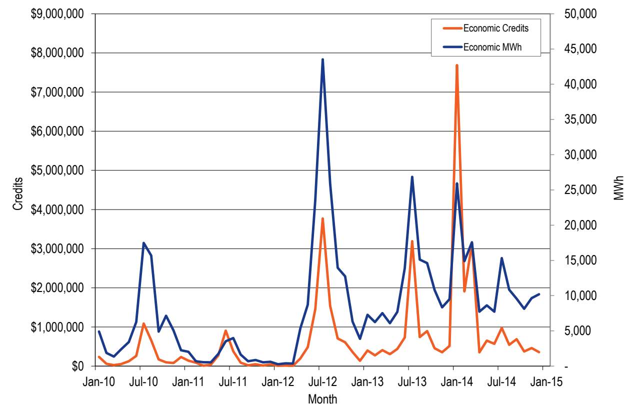



Table 6-5 shows 2013 and 2014 performance in the economic program by control zone and participation type. Total economic program reductions increased 9.1 percent from 133,963 MW in 2013 to 146,194 MW in 2014. The economic credits increased by 103.2 percent from $8,711,873 in 2013, to $17,704,862 in 2014. In several western zones, the credits paid to market participants were higher in 2014 despite the fact that there were lower MWh reductions in 2014 than in 2013. In the AECO, JCPL, PECO, Pepco and RECO zones, credits more than quadrupled and MWh reductions more than

### Table 6-5 PJM economic program participation by zone: 2013 and 2014[26]

| | Credits | | | MWh Reductions | | | Credits per MWh Reduction | | |
|---|---|---|---|---|---|---|---|---|---|
| Zones | 2013 | 2014 | Percent Change | 2013 | 2014 | Percent Change | 2013 | 2014 | Percent Change |
| AECO, JCPL, PECO, Pepco, RECO | $525,588 | $2,429,613 | 362.3% | 4,145 | 9,619 | 132.1% | $126.79 | $252.58 | 99.2% |
| AEP, APS | $244,342 | $323,274 | 32.3% | 3,961 | 3,413 | (13.8%) | $61.68 | $94.71 | 53.5% |
| ATSI, ComEd, DAY, DEOK, DLCO, EKPC | $760,791 | $1,073,531 | 41.1% | 15,124 | 11,232 | (25.7%) | $50.30 | $95.58 | 90.0% |
| BGE, DPL, Met-Ed, PENELEC | $1,107,298 | $1,244,056 | 12.4% | 12,183 | 13,373 | 9.8% | $90.89 | $93.03 | 2.4% |
| Dominion | $5,129,796 | $9,951,828 | 94.0% | 85,967 | 86,974 | 1.2% | $59.67 | $114.42 | 91.8% |
| PPL | $315,730 | $1,602,715 | 407.6% | 3,780 | 7,276 | 92.5% | $83.52 | $220.29 | 163.8% |
| PSEG | $628,328 | $1,079,845 | 71.9% | 8,802 | 14,307 | 62.6% | $71.39 | $75.47 | 5.7% |
| Total | $8,711,873 | $17,704,862 | 103.2% | 133,963 | 146,194 | 9.1% | $65.03 | $121.10 | 86.2% |

26 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements.

doubled. In Dominion, MWh reductions increased by only 1.2 percent while the credits nearly doubled.

Table 6-6 shows total settlements submitted by year for 2009 through 2014. A settlement is counted for every day on which a registration is dispatched in the economic program.

### Table 6-6 Settlements submitted by year in the economic program: 2009 through 2014

| Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| Number of Settlements | 2,227 | 3,781 | 732 | 4,554 | 2,357 | 2,356 |

Table 6-7 shows the number of curtailment service providers (CSPs), and the number of participants in their portfolios, submitting settlements by year for 2009 through 2014. There were 112 fewer active participants in 2014 than in 2013. All participants must be included in a CSP.

Parent companies may own only one CSP or multiple CSPs. All HHI calculations performed in this section are at the parent company level.

Economic demand response was highly concentrated in both 2013 and 2014. Table 6-8 shows the monthly HHI index and the annual HHI index in 2014. The table also lists the share of reductions provided by, and the share of credits claimed by the four largest DR companies in each year. In 2014, 80.4 percent of all Economic DR reductions and 67.8 percent of Economic DR revenue were attributable to the four largest DR companies. The HHI for demand response reductions decreased 473 points, from 8194 in 2013 to 7721 in 2014.

Table 6-9 shows average MWh reductions and credits by hour for 2013 and 2014. The majority of reductions occurred between the hour ending 0700 and hour ending 2100 in these two years. In 2013, 98.0 percent of reductions and 98.8 percent of credits occurred from 0700 to 2100, and in 2014, 90.3 percent of reductions and 86.0 percent of credits occurred from 0700 to 2100.

### Table 6-7 Participants and CSPs submitting settlements in the economic program by year: 2009 through 2014

| | 2009 | | 2010 | | 2011 | | 2012 | | 2013 | | 2014 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 | 15 | 212 | 16 | 258 | 15 | 203 | 22 | 428 | 20 | 276 | 18 | 165 |

### Table 6-8 HHI and market concentration in the economic program: 2013 and 2014

| | HHI | | | Top Four Companies Share of Reduction | | | Top Four Companies Share of Credit | | |
|---|---|---|---|---|---|---|---|---|---|
| Month | 2013 | 2014 | Percent Change | 2013 | 2014 | Change Percent | 2013 | 2014 | Change Percent |
| Jan | 9030 | 7098 | (21.4%) | 98.0% | 86.7% | (11.2%) | 94.1% | 84.2% | (9.9%) |
| Feb | 9556 | 6547 | (31.5%) | 100.0% | 84.1% | (15.9%) | 99.0% | 77.5% | (21.5%) |
| Mar | 9234 | 7744 | (16.1%) | 99.9% | 87.4% | (12.4%) | 99.9% | 88.5% | (11.3%) |
| Apr | 9712 | 8343 | (14.1%) | 100.0% | 100.0% | 0.0% | 100.0% | 100.0% | 0.0% |
| May | 8678 | 8090 | (6.8%) | 99.5% | 98.8% | (0.7%) | 99.8% | 99.1% | (0.7%) |
| Jun | 8326 | 7923 | (4.8%) | 88.2% | 90.8% | 2.6% | 86.0% | 87.1% | 1.1% |
| Jul | 6843 | 8316 | 21.5% | 75.4% | 87.9% | 12.5% | 71.0% | 85.2% | 14.2% |
| Aug | 6916 | 8351 | 20.8% | 98.2% | 97.8% | (0.4%) | 98.5% | 96.7% | (1.8%) |
| Sep | 7545 | 8632 | 14.4% | 92.8% | 89.7% | (3.1%) | 87.4% | 87.4% | (0.1%) |
| Oct | 8183 | 7285 | (11.0%) | 100.0% | 91.8% | (8.2%) | 100.0% | 92.8% | (7.2%) |
| Nov | 8350 | 7684 | (8.0%) | 99.4% | 100.0% | 0.6% | 99.2% | 100.0% | 0.7% |
| Dec | 7638 | 7780 | 1.9% | 93.9% | 99.4% | 5.5% | 92.2% | 99.1% | 6.9% |
| Total | 8194 | 7721 | (5.8%) | 89.8% | 80.4% | (9.4%) | 78.7% | 67.8% | (11.0%) |

### Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: 2013 and 2014

| | MWh Reductions | | | Program Credits | | |
|---|---|---|---|---|---|---|
| Hour Ending (EPT) | 2013 | 2014 | Percent Change | 2013 | 2014 | Percent Change |
| 1 | 168 | 775 | 360% | $5,867 | $127,585 | 2,075% |
| 2 | 156 | 723 | 364% | $4,009 | $112,251 | 2,700% |
| 3 | 156 | 878 | 462% | $3,226 | $149,137 | 4,523% |
| 4 | 155 | 1,550 | 899% | $2,377 | $292,816 | 12,220% |
| 5 | 161 | 1,385 | 762% | $2,406 | $204,016 | 8,381% |
| 6 | 358 | 1,962 | 448% | $8,119 | $319,197 | 3,831% |
| 7 | 5,872 | 5,841 | (1%) | $317,442 | $945,568 | 198% |
| 8 | 7,053 | 7,863 | 11% | $409,748 | $1,177,434 | 187% |
| 9 | 7,371 | 8,848 | 20% | $341,149 | $942,788 | 176% |
| 10 | 6,991 | 8,700 | 24% | $307,253 | $1,046,978 | 241% |
| 11 | 5,282 | 6,354 | 20% | $244,180 | $903,947 | 270% |
| 12 | 4,798 | 5,481 | 14% | $217,928 | $809,129 | 271% |
| 13 | 7,137 | 5,949 | (17%) | $373,084 | $691,043 | 85% |
| 14 | 10,649 | 8,624 | (19%) | $867,635 | $877,242 | 1% |
| 15 | 14,323 | 11,558 | (19%) | $1,027,692 | $974,579 | (5%) |
| 16 | 14,820 | 12,108 | (18%) | $1,180,212 | $1,038,310 | (12%) |
| 17 | 14,664 | 12,478 | (15%) | $1,208,669 | $1,097,671 | (9%) |
| 18 | 14,035 | 13,592 | (3%) | $1,035,230 | $1,357,606 | 31% |
| 19 | 10,653 | 9,974 | (6%) | $649,729 | $1,167,897 | 80% |
| 20 | 5,198 | 8,399 | 62% | $288,522 | $1,203,740 | 317% |
| 21 | 2,394 | 6,205 | 159% | $142,349 | $984,104 | 591% |
| 22 | 899 | 3,423 | 281% | $48,047 | $612,657 | 1,175% |
| 23 | 395 | 1,938 | 390% | $16,186 | $380,048 | 2,248% |
| 24 | 274 | 1,588 | 479% | $10,814 | $289,122 | 2,573% |
| Total | 133,963 | 146,194 | 9% | $8,711,873 | $17,704,862 | 103% |

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in 2013 and 2014. Reductions occurred at all price levels. In 2014, 5.9 percent of MWh reductions and 26.1 percent of program credits occurred during the hours when the applicable zonal LMP was higher than $400 per MWh.

Following Order 745, each month the NBT threshold price is calculated above which the net benefits of DR are deemed to exceed the cost to load. Demand resource (DR) reductions have two effects on the per MWh energy payment by loads and exports. DR reduces LMP by reducing demand in the energy market. At the same time, DR payments cause an additional uplift charge. The NBT threshold price is a monthly estimate calculated from the supply curve of PJM, and it does not incorporate the real-time or day-ahead prices. When the LMP is above the NBT threshold price, the demand response resource receives credit for the full LMP. Demand resources are not paid for any load reductions during hours where the LMP is below the NBT threshold price. About 0.5 percent of DR dispatch occurred during hours with LMP lower than the NBT threshold price.

### Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2013 and 2014

| | MWh Reductions | | | Program Credits | | |
|---|---|---|---|---|---|---|
| LMP | 2013 | 2014 | Percent Change | 2013 | 2014 | Percent Change |
| $0 to $25 | 445 | 722 | 62% | $5,702 | $11,645 | 104% |
| $25 to $50 | 81,354 | 59,906 | (26%) | $3,311,344 | $2,490,876 | (25%) |
| $50 to $75 | 27,172 | 28,318 | 4% | $1,775,006 | $1,859,841 | 5% |
| $75 to $100 | 7,557 | 13,280 | 76% | $719,397 | $1,288,904 | 79% |
| $100 to $125 | 6,438 | 7,426 | 15% | $878,930 | $915,895 | 4% |
| $125 to $150 | 4,324 | 5,263 | 22% | $670,247 | $803,983 | 20% |
| $150 to $175 | 1,516 | 4,222 | 179% | $234,268 | $776,070 | 231% |
| $175 to $200 | 1,020 | 3,557 | 249% | $177,231 | $768,439 | 334% |
| $200 to $225 | 852 | 2,951 | 246% | $147,230 | $672,056 | 356% |
| $225 to $250 | 1,068 | 2,866 | 168% | $182,746 | $713,340 | 290% |
| $250 to $275 | 212 | 2,312 | 989% | $52,692 | $637,912 | 1,111% |
| $275 to $300 | 640 | 1,898 | 197% | $169,186 | $558,849 | 230% |
| $300 to $325 | 374 | 1,569 | 320% | $99,169 | $459,897 | 364% |
| $325 to $350 | 205 | 1,059 | 417% | $19,008 | $359,764 | 1,793% |
| $350 to $375 | 216 | 1,259 | 483% | $50,647 | $435,346 | 760% |
| $375 to $400 | 47 | 916 | 1,851% | $12,574 | $333,491 | 2,552% |
| > $400 | 523 | 8,660 | 1,554% | $206,495 | $4,618,554 | 2,137% |
| Total | 133,963 | 146,183 | 9% | $8,711,873 | $17,704,862 | 103% |

Table 6-11 shows the NBT threshold price from April 2012, when FERC Order 745 was implemented in PJM, through 2014.

### Table 6-11 Result from net benefits tests: April, 2012 through December, 2014

| | Net Benefits Test Threshold Price ($/MWh) | | |
|---|---|---|---|
| Month | 2012 | 2013 | 2014 |
| Jan | | $25.72 | $29.51 |
| Feb | | $26.27 | $30.44 |
| Mar | | $25.60 | $34.93 |
| Apr | $25.89 | $26.96 | $32.59 |
| May | $23.46 | $27.73 | $32.08 |
| Jun | $23.86 | $28.44 | $31.62 |
| Jul | $22.99 | $29.42 | $31.62 |
| Aug | $24.47 | $28.58 | $29.85 |
| Sep | $24.93 | $28.80 | $29.83 |
| Oct | $25.96 | $29.13 | $30.20 |
| Nov | $25.63 | $31.63 | $29.17 |
| Dec | $25.97 | $28.82 | $29.01 |
| Average | $24.80 | $28.09 | $30.91 |

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 2014, the highest zonal LMP in PJM was higher than the NBT threshold price in 7,921 hours out of the entire 8,760 hours, or 90.4 percent of all hours. Reductions occurred in 7,105 hours, or 89.7 percent, of the 7,921 hours in 2014. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in 2013 and 2014.

### Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2013 and 2014

| | Number of Hours | Number of Hours with LMP Higher than NBT | | | Percentage of NBT Hours with DR | | |
|---|---|---|---|---|---|---|---|
| Month | 2013/2014 | 2013 | 2014 | Percent Change | 2013 | 2014 | Change Percent |
| Jan | 744 | 716 | 742 | 3.6% | 78.9% | 93.8% | 14.9% |
| Feb | 672 | 672 | 672 | 0.0% | 89.3% | 92.9% | 3.6% |
| Mar | 743 | 743 | 732 | (1.5%) | 80.8% | 81.8% | 1.1% |
| Apr | 720 | 717 | 661 | (7.8%) | 86.6% | 86.5% | (0.1%) |
| May | 744 | 669 | 694 | 3.7% | 88.3% | 85.3% | (3.0%) |
| Jun | 720 | 597 | 557 | (6.7%) | 94.0% | 87.8% | (6.2%) |
| Jul | 744 | 609 | 540 | (11.3%) | 94.7% | 97.8% | 3.0% |
| Aug | 744 | 550 | 586 | 6.5% | 89.8% | 88.6% | (1.3%) |
| Sep | 720 | 582 | 605 | 4.0% | 88.8% | 90.9% | 2.1% |
| Oct | 744 | 620 | 710 | 14.5% | 86.3% | 93.4% | 7.1% |
| Nov | 721 | 577 | 719 | 24.6% | 92.0% | 96.5% | 4.5% |
| Dec | 744 | 705 | 703 | (0.3%) | 93.6% | 82.4% | (11.3%) |
| Total | 8,760 | 7,757 | 7,921 | 2.1% | 88.3% | 89.7% | 1.4% |

Following the implementation of FERC Order No. 745, DR in PJM is paid by real-time loads and real-time scheduled exports. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges for each zone and for exports. The demand response charges in January 2014 constituted 43.4 percent of the total economic DR charges in 2014. Real-time loads in AEP, Dominion, and ComEd paid the highest DR charges in 2014.

Table 6-14 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in 2013 and 2014. The day-ahead DR charges increased by $3,094,111, or 76 percent, from $4,060,008 in 2013 to $7,154,118 in 2014. The real-time DR charges increased $5,612,973, or 127 percent, from $4,651,866 in 2013 to $10,550,648 in 2014. The load charge for DR increased $0.02/MWh, or 79 percent, from $0.02/MWh in 2013 to $0.04/MWh in 2014.

### Table 6-13 Zonal DR charge: 2014

| Zone | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $88,787 | $21,811 | $36,352 | $4,216 | $6,575 | $7,867 | $16,679 | $7,246 | $10,059 | $3,795 | $5,392 | $4,122 | $212,902 |
| AEP | $1,287,055 | $312,328 | $490,612 | $55,153 | $105,762 | $86,463 | $130,093 | $84,283 | $100,854 | $62,383 | $76,849 | $56,499 | $2,848,334 |
| APS | $499,040 | $121,446 | $194,455 | $20,964 | $38,630 | $32,054 | $54,049 | $31,057 | $39,099 | $21,098 | $28,881 | $22,756 | $1,103,528 |
| ATSI | $610,023 | $155,457 | $248,281 | $30,829 | $57,728 | $48,066 | $71,721 | $45,485 | $56,314 | $32,652 | $39,270 | $30,265 | $1,426,092 |
| BGE | $336,929 | $79,554 | $130,350 | $14,007 | $28,830 | $24,750 | $48,599 | $24,614 | $31,991 | $16,974 | $18,380 | $14,984 | $769,964 |
| ComEd | $751,170 | $204,212 | $329,208 | $35,592 | $77,758 | $70,601 | $83,644 | $70,120 | $75,588 | $41,420 | $48,631 | $35,911 | $1,823,854 |
| DAY | $163,297 | $40,896 | $62,819 | $7,580 | $14,810 | $12,270 | $17,406 | $12,183 | $14,838 | $8,540 | $10,185 | $7,656 | $372,482 |
| DEOK | $248,017 | $62,898 | $93,801 | $10,662 | $23,030 | $19,939 | $27,326 | $19,170 | $22,548 | $11,082 | $14,933 | $10,670 | $564,076 |
| DLCO | $125,595 | $24,946 | $49,291 | $5,212 | $12,433 | $10,406 | $15,241 | $9,580 | $11,024 | $6,562 | $7,942 | $5,981 | $284,214 |
| Dominion | $1,021,400 | $236,410 | $393,303 | $40,645 | $91,199 | $72,760 | $133,387 | $68,250 | $94,651 | $51,725 | $55,078 | $45,427 | $2,304,234 |
| DPL | $199,098 | $46,459 | $75,679 | $7,990 | $12,526 | $13,135 | $27,171 | $12,453 | $15,915 | $8,529 | $10,770 | $8,748 | $438,472 |
| EKPC | $156,880 | $34,851 | $52,705 | $4,838 | $9,578 | $8,339 | $12,025 | $8,238 | $9,468 | $5,082 | $7,929 | $5,404 | $315,336 |
| JCPL | $200,870 | $50,017 | $81,694 | $8,870 | $15,532 | $17,879 | $38,668 | $16,140 | $22,068 | $8,688 | $12,354 | $9,387 | $482,165 |
| Met-Ed | $147,504 | $36,986 | $60,434 | $6,656 | $9,572 | $9,503 | $19,167 | $8,428 | $11,511 | $5,714 | $8,584 | $6,614 | $330,671 |
| PECO | $375,055 | $92,690 | $150,894 | $17,175 | $26,901 | $27,270 | $56,417 | $23,921 | $33,509 | $12,902 | $22,347 | $16,632 | $855,713 |
| PENELEC | $164,067 | $42,050 | $68,023 | $8,248 | $14,718 | $10,794 | $18,958 | $10,720 | $12,976 | $7,928 | $10,361 | $8,064 | $376,906 |
| Pepco | $313,611 | $73,684 | $119,799 | $13,360 | $28,608 | $23,994 | $45,233 | $23,847 | $31,376 | $16,995 | $17,271 | $14,030 | $721,808 |
| PPL | $420,890 | $104,335 | $167,056 | $18,205 | $26,241 | $24,189 | $48,016 | $22,059 | $29,786 | $14,005 | $24,602 | $18,183 | $917,567 |
| PSEG | $368,239 | $92,173 | $150,738 | $18,849 | $30,794 | $31,715 | $66,823 | $28,451 | $39,518 | $18,525 | $23,461 | $18,295 | $887,581 |
| RECO | $12,180 | $3,050 | $5,037 | $658 | $1,098 | $1,239 | $2,527 | $1,141 | $1,546 | $619 | $811 | $638 | $30,544 |
| Export | $199,606 | $72,391 | $168,380 | $21,206 | $18,342 | $16,302 | $44,458 | $17,355 | $25,242 | $20,205 | $18,111 | $16,726 | $638,322 |
| Total | $7,689,314 | $1,908,644 | $3,128,912 | $350,913 | $650,665 | $569,536 | $977,608 | $544,741 | $689,882 | $375,421 | $462,140 | $356,990 | $17,704,767 |

### Table 6-14 Monthly day-ahead and real-time DR charge: 2013 and 2014

| | Day-ahead DR Charge | | | Real-time DR Charge | | | Per MW Charge ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|
| Month | 2013 | 2014 | Percent Change | 2013 | 2014 | Percent Change | 2013 | 2014 | Percent Change |
| Jan | $251,494 | $3,580,411 | 1,324% | $147,937 | $4,108,903 | 2,677% | $0.016 | $0.131 | 725% |
| Feb | $241,179 | $1,148,053 | 376% | $34,565 | $760,591 | 2,100% | $0.011 | $0.038 | 246% |
| Mar | $344,210 | $762,224 | 121% | $64,371 | $2,366,688 | 3,577% | $0.015 | $0.075 | (76%) |
| Apr | $267,301 | $67,996 | (75%) | $39,944 | $282,918 | 608% | $0.013 | $0.012 | (4%) |
| May | $276,352 | $151,962 | (45%) | $161,883 | $498,703 | 208% | $0.018 | $0.024 | 38% |
| Jun | $323,881 | $309,885 | (4%) | $406,716 | $259,651 | (36%) | $0.022 | $0.018 | (20%) |
| Jul | $1,467,622 | $506,523 | (65%) | $1,722,650 | $471,085 | (73%) | $0.068 | $0.031 | (55%) |
| Aug | $182,941 | $158,297 | (13%) | $560,348 | $386,444 | (31%) | $0.020 | $0.019 | (5%) |
| Sep | $437,316 | $143,293 | (67%) | $456,949 | $546,589 | 20% | $0.031 | $0.029 | (7%) |
| Oct | $78,465 | $97,563 | 24% | $377,386 | $277,857 | (26%) | $0.016 | $0.014 | (10%) |
| Nov | $65,311 | $167,769 | 157% | $287,951 | $294,371 | 2% | $0.017 | $0.013 | (26%) |
| Dec | $123,936 | $60,143 | (51%) | $391,166 | $296,847 | (24%) | $0.013 | $0.013 | 3% |
| Total | $4,060,008 | $7,154,118 | 76% | $4,651,866 | $10,550,648 | 127% | $0.024 | $0.043 | 79% |

## Emergency Program

The emergency load response program consists of the limited demand response product in the capacity market during the 2013/2014 Delivery Year and the limited, extended summer and annual demand response product in the capacity market during the 2014/2015 Delivery Year. To participate as a limited demand resource, the provider must clear MW in an RPM auction. Emergency resources receive capacity revenue from the capacity market and also receive revenue from the energy market for reductions during a PJM initiated 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 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 also recommends that demand resources have an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently \$1,000 per MWh.[27]

Emergency demand response was moderately concentrated in 2014. The HHI for emergency demand response registrations increased 231 points, from 1529 in 2013 to 1760 in 2014. In 2014 the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

Table 6-15 shows zonal monthly capacity market revenue to demand resources for 2014. Capacity market revenue increased in 2014 by \$194.5 million, or 44.4 percent, compared to 2013, from \$438.2 million to \$632.8 million, as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 and 2014/2015 delivery years.

Table 6-16 shows the amount of energy efficiency (EE) resources in PJM for 2012/2013 through 2014/2015 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources increased by 24 percent from 1,029.2 MW in the 2013/2014 delivery year to 1,282.4 MW in 2014/2015 Delivery Year.

### Table 6-15 Zonal monthly capacity revenue: 2014

| Zone | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $1,035,717 | $935,486 | $1,035,717 | $1,002,307 | $1,035,717 | $805,435 | $832,282 | $832,282 | $805,435 | $832,282 | $805,435 | $832,282 | $10,790,378 |
| AEP, EKPC | $776,197 | $701,081 | $776,197 | $751,158 | $776,197 | $6,203,447 | $6,410,228 | $6,410,228 | $6,203,447 | $6,410,228 | $6,203,447 | $6,410,228 | $48,032,082 |
| AP | $493,260 | $445,525 | $493,260 | $477,348 | $493,260 | $3,380,132 | $3,492,803 | $3,492,803 | $3,380,132 | $3,492,803 | $3,380,132 | $3,492,803 | $26,514,263 |
| ATSI | $377,750 | $341,193 | $377,750 | $365,564 | $377,750 | $3,717,155 | $3,841,060 | $3,841,060 | $3,717,155 | $3,841,060 | $3,717,155 | $3,841,060 | $28,355,708 |
| BGE | $7,736,807 | $6,988,083 | $7,736,807 | $7,487,232 | $7,736,807 | $5,140,527 | $5,311,878 | $5,311,878 | $5,140,527 | $5,311,878 | $5,140,527 | $5,311,878 | $74,354,831 |
| ComEd | $808,185 | $729,973 | $808,185 | $782,114 | $808,185 | $5,846,358 | $6,041,237 | $6,041,237 | $5,846,358 | $6,041,237 | $5,846,358 | $6,041,237 | $45,640,665 |
| DAY | $44,278 | $39,993 | $44,278 | $42,849 | $44,278 | $872,987 | $902,087 | $902,087 | $872,987 | $902,087 | $872,987 | $902,087 | $6,442,985 |
| DEOK | $16,653 | $15,041 | $16,653 | $16,115 | $16,653 | $330,654 | $341,676 | $341,676 | $330,654 | $341,676 | $330,654 | $341,676 | $2,439,779 |
| DLCO | $148,045 | $133,718 | $148,045 | $143,269 | $148,045 | $840,774 | $5,338,145 | $5,338,145 | $5,165,946 | $868,800 | $840,774 | $868,800 | $19,982,505 |
| Dominion | $605,391 | $546,805 | $605,391 | $585,862 | $605,391 | $5,165,946 | $1,593,999 | $1,593,999 | $1,542,580 | $5,338,145 | $5,165,946 | $5,338,145 | $28,687,601 |
| DPL | $1,979,013 | $1,787,496 | $1,979,013 | $1,915,174 | $1,979,013 | $1,542,580 | $868,800 | $868,800 | $840,774 | $1,593,999 | $1,542,580 | $1,593,999 | $18,491,240 |
| JCPL | $2,288,883 | $2,067,378 | $2,288,883 | $2,215,048 | $2,288,883 | $1,709,946 | $1,766,944 | $1,766,944 | $1,709,946 | $1,766,944 | $1,709,946 | $1,766,944 | $23,346,686 |
| Met-Ed | $2,246,581 | $2,029,170 | $2,246,581 | $2,174,111 | $2,246,581 | $1,558,377 | $1,610,323 | $1,610,323 | $1,558,377 | $1,610,323 | $1,558,377 | $1,610,323 | $22,059,448 |
| PECO | $5,314,219 | $4,799,939 | $5,314,219 | $5,142,792 | $5,314,219 | $3,249,878 | $3,358,207 | $3,358,207 | $3,249,878 | $3,358,207 | $3,249,878 | $3,358,207 | $49,067,852 |
| PENELEC | $2,980,723 | $2,692,266 | $2,980,723 | $2,884,571 | $2,980,723 | $1,675,004 | $1,730,838 | $1,730,838 | $1,675,004 | $1,730,838 | $1,675,004 | $1,730,838 | $26,467,373 |
| Pepco | $4,229,396 | $3,820,100 | $4,229,396 | $4,092,964 | $4,229,396 | $3,467,834 | $3,583,429 | $3,583,429 | $3,467,834 | $3,583,429 | $3,467,834 | $3,583,429 | $45,338,470 |
| PPL | $7,253,736 | $6,551,762 | $7,253,736 | $7,019,745 | $7,253,736 | $5,215,729 | $5,389,586 | $5,389,586 | $5,215,729 | $5,389,586 | $5,215,729 | $5,389,586 | $72,538,246 |
| PSEG | $8,859,978 | $8,002,561 | $8,859,978 | $8,574,172 | $8,859,978 | $5,460,187 | $5,642,193 | $5,642,193 | $5,460,187 | $5,642,193 | $5,460,187 | $5,642,193 | $82,106,000 |
| RECO | $257,721 | $232,781 | $257,721 | $249,408 | $257,721 | $118,962 | $122,927 | $122,927 | $118,962 | $122,927 | $118,962 | $122,927 | $2,103,948 |
| Total | $47,452,531 | $42,860,351 | $47,452,531 | $45,921,805 | $47,452,531 | $56,301,913 | $58,178,643 | $58,178,643 | $56,301,913 | $58,178,643 | $56,301,913 | $58,178,643 | $632,760,060 |

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

### Table 6-16 Energy efficiency resources by MW: 2012/2013 through 2014/2015 Delivery Year

| | EE ICAP (MW) | | | EE UCAP (MW) | | |
|---|---|---|---|---|---|---|
| | 2012/2013 | 2013/2014 | 2014/2015 | 2012/2013 | 2013/2014 | 2014/2015 |
| Total | 609.8 | 990.9 | 1,231.8 | 631.2 | 1,029.2 | 1,282.4 |

Table 6-17 shows the number of customers and the nominated MW by product type and lead time for the 2014/2015 Delivery Year. The annual and extended summer products are new for the 2014/2015 Delivery Year. The quick lead time product, which is obligated to respond within 30 minutes, is also new for the 2014/2015 Delivery Year. The quick lead time product has 7.5 percent of all nominated MW with 704.0 MW and only 22 locations.

The quick lead time product was defined after the auctions cleared. FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014.[28] 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.[29]

### Table 6-17 Lead time by product type: 2014/2015 Delivery Year

| Lead Type | Product Type | Locations | Nominated MW |
|---|---|---|---|
| Long Lead (120 Minutes) | Annual and Extended Summer | 2,079 | 1,130.9 |
| | Limited | 13,781 | 7,039.8 |
| Short Lead (60 Minutes) | Annual, Extended Summer and Limited | 55 | 485.7 |
| Quick Lead (30 Minutes) | Annual and Limited | 22 | 704.0 |
| Total | | 15,937 | 9,360.3 |

Table 6-18 shows the MW registered by measurement and verification method and by load drop method for the 2013/2014 Delivery Year. Of the DR MW committed, 3.5 percent use the guaranteed load drop (GLD) measurement and verification method, 87.0 percent use the firm service level (FSL) method and 9.5 percent use direct load control (DLC).

The program type is submitted as "Other" for 1.5 percent of committed MW, which does not explain the basis for the reduction. The choice of other is no longer a valid option for new registrations as of the 2014/2015 Delivery Year.

Table 6-19 shows the MW registered by measurement and verification method and by load drop method for the 2014/2015 Delivery Year. Of the DR MW committed, 2.4 percent use the guaranteed load drop (GLD) measurement and verification method, 91.2 percent use the firm service level (FSL) method and 6.3 percent use direct load control (DLC). FSL registrations increased by 751.8 MW while GLD registrations decreased by 86.7 MW and DLC registrations decreased by 260.5 MW from the 2013/2014 delivery year to the 2014/2015 delivery year.

### Table 6-18 Reduction MW by each demand response method: 2013/2014 Delivery Year

| Program Type | On-site Generation MW | HVAC MW | Refrigeration MW | Lighting MW | Manufacturing MW | Water Heating MW | Other MW | Total | Percent by type |
|---|---|---|---|---|---|---|---|---|---|
| Firm Service Level | 1,810.8 | 1,414.7 | 241.7 | 737.0 | 3,382.1 | 77.8 | 121.0 | 7,785.0 | 87.0% |
| Guaranteed Load Drop | 69.9 | 169.2 | 4.1 | 23.6 | 33.7 | 0.8 | 12.0 | 313.2 | 3.5% |
| Non hourly metered sites (DLC) | 0.0 | 812.6 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 | 852.6 | 9.5% |
| Total | 1,880.7 | 2,396.6 | 245.7 | 760.6 | 3,415.7 | 118.6 | 133.0 | 8,950.8 | 100.0% |
| Percent by method | 21.0% | 26.8% | 2.7% | 8.5% | 38.2% | 1.3% | 1.5% | 100.0% | |

### Table 6-19 Reduction MW by each demand response method: 2014/2015 Delivery Year

| Program Type | On-site Generation MW | HVAC MW | Refrigeration MW | Lighting MW | Manufacturing MW | Water Heating or Other MW | Total | Percent by Type |
|---|---|---|---|---|---|---|---|---|
| Firm Service Level | 2,119.6 | 1,970.8 | 207.4 | 740.6 | 3,428.5 | 69.9 | 8,536.8 | 91.2% |
| Guaranteed Load Drop | 25.2 | 152.9 | 1.8 | 12.2 | 33.9 | 0.5 | 226.6 | 2.4% |
| Non hourly metered sites (DLC) | 0.0 | 551.1 | 0.0 | 0.0 | 0.0 | 41.0 | 592.1 | 6.3% |
| Total | 2,144.7 | 2,674.8 | 209.2 | 752.8 | 3,462.4 | 111.4 | 9,355.4 | 100.0% |
| Percent by method | 22.9% | 28.6% | 2.2% | 8.0% | 37.0% | 1.2% | 100.0% | |

28 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).

29 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).

Table 6-20 shows the fuel type used by the on-site generators identified in Table 6-18 for the 2013/2014 Delivery Year. Of the 21.0 percent of emergency demand response identified as using on-site generation, 93.8 percent of MW are diesel, 5.3 percent are natural gas and 0.9 percent is coal, oil, other.

### Table 6-20 On-site generation fuel type by MW: 2013/2014 Delivery Year

| Fuel Type | MW | Percent |
|---|---|---|
| Coal, Oil, Other | 16.3 | 0.9% |
| Diesel | 1,764.1 | 93.8% |
| Natural Gas | 100.2 | 5.3% |
| Total | 1,880.7 | 100.0% |

Table 6-21 shows the fuel type used in the on-site generators identified in Table 6-19 for the 2014/2015 Delivery Year. Of the 22.9 percent of emergency demand response identified as using on-site generation, 85.5 percent of MW are diesel, 11.7 percent are natural gas and 2.8 percent is coal, gasoline, kerosene, oil, propane, waste products.

### Table 6-21 On-site generation fuel type by MW: 2014/2015 Delivery Year

| Fuel Type | MW | Percent |
|---|---|---|
| Coal, Gasoline, Kerosene, Oil, Propane, Waste Products | 59.6 | 2.8% |
| Diesel | 1,834.1 | 85.5% |
| Natural Gas | 251.0 | 11.7% |
| Total | 2,144.7 | 100.0% |

## Emergency Event Reported Compliance

PJM declared eight emergency events in 2014, two on January 7, one on January 8, one on January 22, two on January 23, one on January 24 and one on March 4. There were 13 events during the 2013/2014 Delivery Year, two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of the 2014 events occurred outside of the summer compliance period, none were considered in PJM's compliance assessment.[30] Table 6-22 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM increased from 1.4 percent in the 2011/2012 Delivery Year to 9.3 percent of capacity resources in the 2014/2015 Delivery Year.

Table 6-23 lists PJM emergency load management events declared by PJM in 2014 and the affected zones. The SWMAAC LDA was the only LDA called for all eight events. All demand response events called in 2014 were voluntary, so no penalties are assessed for under compliance.

Participants in the emergency demand response program are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance based on each hour to accurately report reductions during demand response events. This would be consistent with the rules that apply to generation resources. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.

PJM deployed both long lead time resources, which require more than one hour but less than two hours notification, and short lead time resources, which require less than an hour notification during the 2013/2014 Delivery Year. Any resource is eligible to be either a short lead time or long lead time resource, and there are no differences in payment for these resources. Approximately 99.5 percent of registrations, accounting for 91.6 percent of registered MW, are designated as long lead time resources. The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources. This will enable quicker response and greater flexibility.

### Table 6-22 Demand response cleared MW UCAP for PJM: 2011/2012 through 2014/2015 Delivery Year

| | 2011/2012 Delivery Year | | 2012/2013 Delivery Year | | 2013/2014 Delivery Year | | 2014/2015 Delivery Year | |
|---|---|---|---|---|---|---|---|---|
| | DR Cleared MW UCAP | DR Percent of Capacity MW UCAP | DR Cleared MW UCAP | DR Percent of Capacity MW UCAP | DR Cleared MW UCAP | DR Percent of Capacity MW UCAP | DR Cleared MW UCAP | DR Percent of Capacity MW UCAP |
| Total | 1,826.6 | 1.4% | 8,740.9 | 6.2% | 10,779.6 | 6.7% | 14,943.0 | 9.3% |

30 Annual and extended summer demand response products were not active in PJM's demand response program until June 1, 2014.

### Table 6-23 PJM declared load management events: 2014

| Event Date | Event Times | Compliance Hours | Minutes not Measured for Compliance | Lead Time | Geographical Area |
|---|---|---|---|---|---|
| 7-Jan-14 | 5:30-11:00 | None | 330 | Short Lead | RTO |
| | 6:30-11:00 | None | 270 | Long Lead | RTO |
| | 16:00-18:15 | None | 135 | Short Lead | RTO |
| | 17:00-18:15 | None | 75 | Long Lead | RTO |
| 8-Jan-14 | 6:00-7:00 | None | 60 | Short Lead | RTO |
| | 7:00-7:00 | None | 0 | Long Lead | RTO |
| 22-Jan-14 | 15:00-21:00 | None | 360 | Short Lead | SWMAAC |
| | 16:00-21:00 | None | 300 | Long Lead | SWMAAC |
| 23-Jan-14 | 5:30-8:30 | None | 180 | Short Lead | MAAC, APS, Dominion |
| | 6:30-8:30 | None | 120 | Long Lead | MAAC, APS, Dominion |
| | 15:00-19:00 | None | 240 | Short Lead | MAAC, APS, Dominion |
| | 16:00-19:00 | None | 180 | Long Lead | MAAC, APS, Dominion |
| 24-Jan-14 | 5:30-8:45 | None | 195 | Short Lead | MAAC, APS, Dominion |
| | 6:30-8:45 | None | 135 | Long Lead | MAAC, APS, Dominion |
| 4-Mar-14 | 5:30-8:30 | None | 180 | Short Lead | RTO |
| | 6:30-8:30 | None | 120 | Long Lead | RTO |

There were eight events in 2014, on January 7, 2014, January 8, 2014, January 22, 2014, January 23, 2014, January 24, 2014, and March 4, 2014, for which PJM requested voluntary dispatch of emergency demand side resources. All of these events occurred outside of the limited demand response product's window of mandatory response from June through September and from 12:00 to 20:00.[31] Compliance penalties are not applicable to the events in the first nine months of 2014 for that reason, but resources that did curtail received emergency energy payments, which are paid by PJM market participants in proportion to their net purchases in the real-time market.

Subzonal dispatch by zip code was voluntary for the 2013/2014 Delivery Year, but is mandatory beginning on June 1, 2014, with the 2014/2015 Delivery Year. PJM proposed to allow compliance to be measured across zones within a compliance aggregation area (CAA). This would change 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.[32] More locational deployment of load management resources would improve efficiency. 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 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.[33] 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.

Emergency demand response customers that registered for economic demand response had an adjusted baseline for the emergency event days. The change of baseline resulted in a greater calculated load reduction for the PJM system emergency event days. The changes in reported load reductions reflect emergency resources registering as economic resources to have modified

31 Annual and extended summer demand response products were not active in PJM's demand response program until June 1, 2014.

32 See "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER14-822-002 (July 25, 2014), at 2.

33 PJM. OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

baselines for measurement during the emergency voluntary event days.

Table 6-24 shows the performance for the first January 7, 2014, event. The first column shows the nominated value, which is the reduction capability indicated for each registration. The nominated MW are used to fulfill the committed MW capacity obligation and may exceed the committed MW. The second column shows load management committed MW, which are used to assess RPM compliance. The committed MW are the MW cleared in the RPM auction. The third column shows the reported load reduction in MW during the hours of an event. The reported load reduction is reported by PJM and does not include load increases. The fourth column shows the observed load reduction in MWh, which includes all reported reduction values, including load increases. The observed load reduction is calculated by the MMU. The observed load reduction is a conservative estimate of what occurred during the demand response events as load increases are not required to be reported. Compliance is calculated by comparing the load reduction during an event to the committed MW value.

The APS, ComEd, DAY, DEOK and EKPC zones did not submit any data for this event. Since the event was voluntary, none of these customers responded or received payments for this event. The reported compliance for the DPL Control Zone was 104.7 percent. Overall, the reported compliance for the first event on January 7, 2014, was 39.9 percent, or 3,007.2 MW out of 7,535.7 MW committed. The observed compliance was 30.7 percent, or 2,314.6 MW, a difference of 692.6 MW compared to the reported load reduction.

The second event on January 7, 2014, called both long and short lead resources for the RTO at 1600 and ended the event at 1815 EPT. Long lead resources were only dispatched for one hour during this event, even though minimum dispatch is two hours for demand resources. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. As a result, the effective dispatch period for long lead resources was actually from 1700 to 1900 EPT. Short lead resources were dispatched for more than two hours.

### Table 6-24 Demand response event performance: January 7, 2014 (Event 1)

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 25.0 | 20.6 | 4.4 | 24.4% | 20.1% |
| AEP | 1,635.7 | 1,253.6 | 792.3 | 683.5 | 108.8 | 63.2% | 54.5% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| ATSI | 796.1 | 683.1 | 452.9 | 349.3 | 103.6 | 66.3% | 51.1% |
| BGE | 826.6 | 627.2 | 217.9 | 191.7 | 26.2 | 34.7% | 30.6% |
| ComEd | 1,129.8 | 820.3 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DAY | 96.7 | 68.6 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DEOK | 436.2 | 155.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DLCO | 113.1 | 69.2 | 33.3 | 4.2 | 29.1 | 48.1% | 6.1% |
| Dominion | 872.4 | 757.0 | 516.4 | 445.9 | 70.4 | 68.2% | 58.9% |
| DPL | 301.7 | 65.9 | 69.1 | 51.5 | 17.5 | 104.7% | 78.1% |
| EKPC | 110.3 | 79.9 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| JCPL | 209.1 | 156.7 | 81.4 | 61.6 | 19.8 | 51.9% | 39.3% |
| Met-Ed | 233.9 | 173.9 | 80.8 | 56.9 | 24.0 | 46.5% | 32.7% |
| PECO | 587.5 | 410.3 | 200.0 | 147.5 | 52.5 | 48.7% | 35.9% |
| PENELEC | 330.1 | 265.1 | 67.4 | 0.1 | 67.3 | 25.4% | 0.0% |
| Pepco | 795.8 | 372.0 | 108.1 | 81.3 | 26.8 | 29.1% | 21.8% |
| PPL | 800.0 | 621.1 | 249.7 | 144.4 | 105.2 | 40.2% | 23.3% |
| PSEG, RECO | 488.7 | 354.6 | 113.0 | 76.2 | 36.9 | 31.9% | 21.5% |
| Total | 10,562.6 | 7,535.7 | 3,007.2 | 2,314.6 | 692.6 | 39.9% | 30.7% |

Table 6-25 Demand response event performance: January 7, 2014 (Event 2)

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 23.4 | 20.9 | 2.6 | 22.9% | 20.4% |
| AEP | 1,635.7 | 1,253.6 | 872.4 | 740.6 | 131.8 | 69.6% | 59.1% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| ATSI | 796.1 | 683.1 | 534.9 | 452.3 | 82.6 | 78.3% | 66.2% |
| BGE | 826.6 | 627.2 | 230.9 | 210.2 | 20.7 | 36.8% | 33.5% |
| ComEd | 1,129.8 | 820.3 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DAY | 96.7 | 68.6 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DEOK | 436.2 | 155.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DLCO | 113.1 | 69.2 | 32.6 | (16.3) | 48.9 | 47.1% | (23.6%) |
| Dominion | 872.4 | 757.0 | 513.5 | 465.2 | 48.3 | 67.8% | 61.5% |
| DPL | 301.7 | 65.9 | 69.8 | 56.4 | 13.4 | 105.9% | 85.6% |
| EKPC | 110.3 | 79.9 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| JCPL | 209.1 | 156.7 | 78.6 | 58.0 | 20.6 | 50.2% | 37.0% |
| Met-Ed | 233.9 | 173.9 | 85.4 | 71.7 | 13.6 | 49.1% | 41.2% |
| PECO | 587.5 | 410.3 | 190.8 | 150.3 | 40.5 | 46.5% | 36.6% |
| PENELEC | 330.1 | 265.1 | 97.7 | 60.3 | 37.4 | 36.8% | 22.8% |
| Pepco | 795.8 | 372.0 | 111.3 | 92.1 | 19.2 | 29.9% | 24.8% |
| PPL | 800.0 | 621.1 | 252.4 | 174.3 | 78.1 | 40.6% | 28.1% |
| PSEG, RECO | 488.7 | 354.6 | 109.3 | 68.4 | 41.0 | 30.8% | 19.3% |
| Total | 10,562.6 | 7,535.7 | 3,203.0 | 2,604.4 | 598.6 | 42.5% | 34.6% |

Table 6-25 shows the performance for the second January 7, 2014, event. The APS, ComEd, DAY, DEOK and EKPC zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 105.9 percent, or 69.8 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 85.6 percent, or 56.4 MW out of 65.9 MW committed. Overall, the reported compliance for the second event on January 7, 2014, was 42.5 percent, or 3,203.0 MW out of 7,535.7 MW committed. The observed compliance was 34.6 percent, or 2,604.4 MW, a difference of 598.6 MW compared to the reported load reduction.

There was one event on January 8, 2014. The event was called for both long and short lead resources for the RTO at 500 and ended the event at 700 EPT. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. Short lead resources were active for one hour and long lead resources were not active during this call.

Table 6-26 shows the performance for the January 8, 2014, event. The APS, ComEd, DAY, DEOK and EKPC zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 64.4 percent, or 42.4 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 56.9 percent, or 37.5 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 8, 2014, was 30.4 percent, or 2,289.7 MW out of 7,537.7 MW committed. The observed compliance was 22.3 percent, or 1,683.0 MW, a difference of 606.8 MW compared to the reported load reduction.

There was one event on January 22, 2014. The event was called for both long and short lead resources for the SWMAAC LDA at 1400 and ended the event at 2100 EPT.

## Table 6-26 Demand response event performance: January 8, 2014

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 18.1 | 16.1 | 1.9 | 17.6% | 15.8% |
| AEP | 1,635.7 | 1,253.6 | 752.9 | 628.1 | 124.8 | 60.1% | 50.1% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| ATSI | 796.1 | 683.1 | 364.6 | 274.0 | 90.7 | 53.4% | 40.1% |
| BGE | 826.6 | 627.2 | 132.2 | 110.1 | 22.1 | 21.1% | 17.6% |
| ComEd | 1,129.8 | 820.3 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DAY | 96.7 | 68.6 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DEOK | 436.2 | 155.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DLCO | 113.1 | 69.2 | 17.1 | 9.2 | 7.9 | 24.7% | 13.3% |
| Dominion | 872.4 | 757.0 | 359.4 | 279.2 | 80.2 | 47.5% | 36.9% |
| DPL | 301.7 | 65.9 | 42.4 | 37.5 | 4.9 | 64.4% | 56.9% |
| EKPC | 110.3 | 79.9 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| JCPL | 209.1 | 156.7 | 59.0 | 42.4 | 16.5 | 37.6% | 27.1% |
| Met-Ed | 233.9 | 173.9 | 54.3 | 14.3 | 40.0 | 31.2% | 8.2% |
| PECO | 587.5 | 410.3 | 129.7 | 91.0 | 38.7 | 31.6% | 22.2% |
| PENELEC | 330.1 | 265.1 | 46.5 | (6.0) | 52.5 | 17.5% | (2.3%) |
| Pepco | 795.8 | 372.0 | 61.1 | 42.0 | 19.1 | 16.4% | 11.3% |
| PPL | 800.0 | 621.1 | 166.1 | 87.9 | 78.2 | 26.7% | 14.2% |
| PSEG, RECO | 488.7 | 354.6 | 86.2 | 57.1 | 29.2 | 24.3% | 16.1% |
| Total | 10,562.6 | 7,535.7 | 2,289.7 | 1,683.0 | 606.8 | 30.4% | 22.3% |

## Table 6-27 Demand response event performance: January 22, 2014

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| BGE | 826.6 | 627.2 | 239.6 | 218.5 | 21.1 | 38.2% | 34.8% |
| Pepco | 795.8 | 372.0 | 166.1 | 148.8 | 17.3 | 44.7% | 40.0% |
| Total | 1,622.5 | 999.2 | 405.7 | 367.3 | 38.4 | 40.6% | 36.8% |

## Table 6-28 Demand response event performance: January 23, 2014 (Event 1)

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 20.3 | 18.5 | 1.8 | 19.8% | 18.0% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| BGE | 826.6 | 627.2 | 226.8 | 192.9 | 33.9 | 36.2% | 30.8% |
| Dominion | 872.4 | 757.0 | 516.3 | 457.8 | 58.5 | 68.2% | 60.5% |
| DPL | 301.7 | 65.9 | 53.4 | 39.8 | 13.6 | 80.9% | 60.3% |
| JCPL | 209.1 | 156.7 | 82.3 | 55.7 | 26.6 | 52.5% | 35.5% |
| Met-Ed | 233.9 | 173.9 | 90.3 | 66.3 | 23.9 | 51.9% | 38.2% |
| PECO | 587.5 | 410.3 | 199.7 | 145.5 | 54.2 | 48.7% | 35.5% |
| PENELEC | 330.1 | 265.1 | 50.7 | (5.7) | 56.4 | 19.1% | (2.1%) |
| Pepco | 795.8 | 372.0 | 165.5 | 138.5 | 27.0 | 44.5% | 37.2% |
| PPL | 800.0 | 621.1 | 264.4 | 143.7 | 120.6 | 42.6% | 23.1% |
| PSEG | 482.3 | 350.6 | 123.7 | 90.0 | 33.7 | 35.3% | 25.7% |
| RECO | 6.4 | 4.0 | 6.2 | 6.0 | 0.2 | 154.2% | 149.2% |
| Total | 6,244.7 | 4,405.6 | 1,799.5 | 1,349.0 | 450.5 | 40.8% | 30.6% |

Table 6-27 shows the performance for the January 22, 2014, event. The reported compliance for the BGE Control Zone was 38.2 percent, or 239.6 MW out of 627.2 MW committed. The observed compliance for the BGE Control Zone was 34.8 percent, or 218.5 MW out of 627.2 MW committed. Overall, the reported compliance for the event on January 22, 2014, was 40.6 percent, or 405.7 MW out of 999.2 MW committed. The observed compliance was 36.8 percent, or 367.3 MW, a difference of 38.4 MW compared to the reported load reduction.

There were two events on January 23, 2014. The first event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 830 EPT.

Table 6-28 shows the performance for the first January 23, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the RECO Control Zone was 154.2 percent, or 6.2 MW out of 4.0 MW committed. The observed compliance for the RECO Control Zone was 149.2 percent, or 6.0 MW out of 4.0 MW committed. Overall, the reported compliance for the first event on January 23, 2014, was 40.8 percent, or 1,799.5 MW out of 4,405.6 MW committed. The observed compliance was 30.6 percent, or 1,349.0 MW, a difference of 450.5 MW compared to the reported load reduction.

The second event on January 23, 2014, was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 1400 and ended the event at 1900 EPT.

Table 6-29 shows the performance for the second January 23, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the RECO Control Zone was 69.6 percent, or 2.8 MW out of 4.0 MW committed. The observed compliance for the RECO Control Zone was 67.6 percent, or 2.7 MW out of 4.0 MW committed. Overall, the reported compliance for the second event on January 23, 2014, was 40.2 percent, or 1,773.2 MW out of 4,405.6 MW committed. The observed compliance was 33.0 percent, or 1,452.8 MW, a difference of 320.4 MW compared to the reported load reduction.

There was one event on January 24, 2014. The event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 845 EPT.

Table 6-30 shows the performance for the January 24, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the DPL Control Zone was 60.1 percent, or 39.6 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 50.0 percent, or 33.0 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 24, 2014, was 33.1 percent, or 1,459.1 MW out of 4,405.6 MW committed. The observed compliance was 24.9 percent, or 1,095.2 MW, a difference of 363.9 MW compared to the reported load reduction.

### Table 6-29 Demand response event performance: January 23, 2014 (Event 2)

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 19.4 | 17.9 | 1.5 | 18.9% | 17.4% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| BGE | 826.6 | 627.2 | 225.4 | 199.2 | 26.2 | 35.9% | 31.8% |
| Dominion | 872.4 | 757.0 | 547.1 | 508.3 | 38.8 | 72.3% | 67.1% |
| DPL | 301.7 | 65.9 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| JCPL | 209.1 | 156.7 | 81.5 | 54.7 | 26.8 | 52.0% | 34.9% |
| Met-Ed | 233.9 | 173.9 | 98.4 | 85.1 | 13.3 | 56.6% | 49.0% |
| PECO | 587.5 | 410.3 | 195.6 | 148.2 | 47.4 | 47.7% | 36.1% |
| PENELEC | 330.1 | 265.1 | 61.0 | 25.4 | 35.6 | 23.0% | 9.6% |
| Pepco | 795.8 | 372.0 | 167.8 | 150.2 | 17.6 | 45.1% | 40.4% |
| PPL | 800.0 | 621.1 | 263.4 | 181.0 | 82.4 | 42.4% | 29.2% |
| PSEG | 482.3 | 350.6 | 110.8 | 80.1 | 30.7 | 31.6% | 22.8% |
| RECO | 6.4 | 4.0 | 2.8 | 2.7 | 0.1 | 69.6% | 67.6% |
| Total | 6,244.7 | 4,405.6 | 1,773.2 | 1,452.8 | 320.4 | 40.2% | 33.0% |

## Table 6-30 Demand response event performance: January 24, 2014

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 18.3 | 16.6 | 1.7 | 17.9% | 16.2% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| BGE | 826.6 | 627.2 | 156.3 | 133.2 | 23.2 | 24.9% | 21.2% |
| Dominion | 872.4 | 757.0 | 446.2 | 385.7 | 60.4 | 58.9% | 51.0% |
| DPL | 301.7 | 65.9 | 39.6 | 33.0 | 6.6 | 60.1% | 50.0% |
| JCPL | 209.1 | 156.7 | 64.3 | 39.4 | 24.9 | 41.1% | 25.2% |
| Met-Ed | 233.9 | 173.9 | 83.0 | 60.8 | 22.3 | 47.8% | 35.0% |
| PECO | 587.5 | 410.3 | 161.7 | 116.1 | 45.7 | 39.4% | 28.3% |
| PENELEC | 330.1 | 265.1 | 50.7 | 9.4 | 41.3 | 19.1% | 3.6% |
| Pepco | 795.8 | 372.0 | 123.0 | 98.9 | 24.1 | 33.1% | 26.6% |
| PPL | 800.0 | 621.1 | 209.8 | 127.5 | 82.4 | 33.8% | 20.5% |
| PSEG, RECO | 488.7 | 354.6 | 106.0 | 74.6 | 31.4 | 29.9% | 21.0% |
| Total | 6,244.7 | 4,405.6 | 1,459.1 | 1,095.2 | 363.9 | 33.1% | 24.9% |

## Table 6-31 Demand response event performance: March 4, 2014

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 17.1 | 14.3 | 2.8 | 16.7% | 13.9% |
| AEP | 1,635.7 | 1,253.6 | 764.2 | 530.9 | 233.3 | 61.0% | 42.3% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| ATSI | 796.1 | 683.1 | 484.5 | 401.3 | 83.2 | 70.9% | 58.7% |
| BGE | 826.6 | 627.2 | 183.1 | 160.9 | 22.2 | 29.2% | 25.7% |
| ComEd | 1,129.8 | 820.3 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DAY | 96.7 | 68.6 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DEOK | 436.2 | 155.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DLCO | 113.1 | 69.2 | 20.3 | 10.2 | 10.1 | 29.3% | 14.7% |
| Dominion | 872.4 | 757.0 | 430.4 | 370.7 | 59.7 | 56.9% | 49.0% |
| DPL | 301.7 | 65.9 | 50.0 | 45.9 | 4.1 | 75.9% | 69.7% |
| EKPC | 110.3 | 79.9 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| JCPL | 209.1 | 156.7 | 62.5 | 41.1 | 21.4 | 39.9% | 26.3% |
| Met-Ed | 233.9 | 173.9 | 65.1 | 34.0 | 31.1 | 37.5% | 19.6% |
| PECO | 587.5 | 410.3 | 176.8 | 138.7 | 38.1 | 43.1% | 33.8% |
| PENELEC | 330.1 | 265.1 | 52.4 | (1.6) | 53.9 | 19.7% | (0.6%) |
| Pepco | 795.8 | 372.0 | 107.3 | 87.4 | 20.0 | 28.9% | 23.5% |
| PPL | 800.0 | 621.1 | 217.1 | 119.7 | 97.3 | 34.9% | 19.3% |
| PSEG, RECO | 488.7 | 354.6 | 99.5 | 78.4 | 21.1 | 28.1% | 22.1% |
| Total | 10,562.6 | 7,535.7 | 2,730.3 | 2,031.9 | 698.4 | 36.2% | 27.0% |

## Table 6-32 Aggregated load management event performance: 2014

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 124.9 | 102.5 | 20.2 | 17.8 | 2.4 | 19.7% | 17.4% |
| AEP | 1,635.7 | 1,253.6 | 698.4 | 557.2 | 141.1 | 55.7% | 44.4% |
| APS | 674.0 | 499.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| ATSI | 796.1 | 683.1 | 401.1 | 328.2 | 72.9 | 58.7% | 48.1% |
| BGE | 826.6 | 627.2 | 229.9 | 198.2 | 31.7 | 36.7% | 31.6% |
| ComEd | 1,129.8 | 820.3 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DAY | 96.7 | 68.6 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DEOK | 436.2 | 155.4 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| DLCO | 113.1 | 69.2 | 36.3 | 10.1 | 26.2 | 52.4% | 14.6% |
| Dominion | 872.4 | 757.0 | 430.3 | 381.6 | 48.7 | 56.9% | 50.4% |
| DPL | 301.7 | 65.9 | 42.7 | 33.7 | 9.0 | 64.8% | 51.1% |
| EKPC | 110.3 | 79.9 | 0.0 | 0.0 | 0.0 | 0.0% | 0.0% |
| JCPL | 209.1 | 156.7 | 72.1 | 46.4 | 25.7 | 46.0% | 29.6% |
| Met-Ed | 233.9 | 173.9 | 90.4 | 66.6 | 23.8 | 52.0% | 38.3% |
| PECO | 587.5 | 410.3 | 167.3 | 120.0 | 47.3 | 40.8% | 29.3% |
| PENELEC | 330.1 | 265.1 | 63.0 | 18.6 | 44.4 | 23.8% | 7.0% |
| Pepco | 795.8 | 372.0 | 139.4 | 110.6 | 28.8 | 37.5% | 29.7% |
| PPL | 800.0 | 621.1 | 217.3 | 132.3 | 85.0 | 35.0% | 21.3% |
| PSEG, RECO | 488.7 | 354.6 | 99.1 | 70.9 | 28.2 | 27.9% | 20.0% |
| Weighted Total | 10,562.6 | 7,535.7 | 2,840.9 | 2,198.6 | 428.9 | 37.7% | 29.2% |

There was one event on March 4, 2014. The event was called for both long and short lead resources for the RTO at 430 and ended the event at 830 EPT.

Table 6-31 shows the performance for the March 4, 2014, event. The APS, ComEd, DAY, DEOK and EKPC Control Zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 75.9 percent, or 50.0 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 69.7 percent, or 45.9 MW out of 65.9 MW committed. Overall, the reported compliance for the event on March 4, 2014, was 36.2 percent, or 2,730.3 MW out of 7,535.7 MW committed. The observed compliance was 27.0 percent, or 2,031.9 MW, a difference of 698.4 MW compared to the reported load reduction.

Table 6-32 shows aggregated load management event performance for the eight demand response emergency events for 2014. The reported compliance for all PJM control zones was 37.7 percent in 2014 for resources called during emergency events, while observed compliance was 29.2 percent. The reported compliance for the DPL Control Zone was 64.8 percent, or 42.7 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 51.1 percent, or 33.7 MW out of 65.9 MW committed. The reported and observed compliance for the DPL Control Zone were the highest in PJM. The reported and observed compliance for the APS, ComEd, DAY, DEOK and EKPC control zones reported were 0.0 percent, the lowest in PJM.

The average observed compliance for the BGE Control Zone, which responded to all eight emergency events in 2014, was 36.7 percent, or 229.9 MW out of 627.2 MW committed. The average observed compliance for the Pepco Control Zone, which also responded to all eight emergency events in 2014, was 37.5 percent, or 139.4 MW out of 621.1 MW committed.

Performance for specific customers varied significantly. Table 6-33 shows the distribution of participant event days by performance levels for the eight events in the 2013/2014 compliance period. Table 6-33 includes the participation for all resources dispatched for the emergency events. For these events, 73.2 percent of participant event days showed no reduction, load increased or participants did not report data. For these events 83.7 percent of participant event days provided less than half of their nominated MW, while 81.0 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, 92.0 percent, provided less than 100 percent reduction compared to their nominated MW, while 91.2 percent of the nominated MW provided less than 100 percent reduction.

### Table 6-33 Distribution of participant event days and nominated MW across ranges of performance levels across the events: 2014

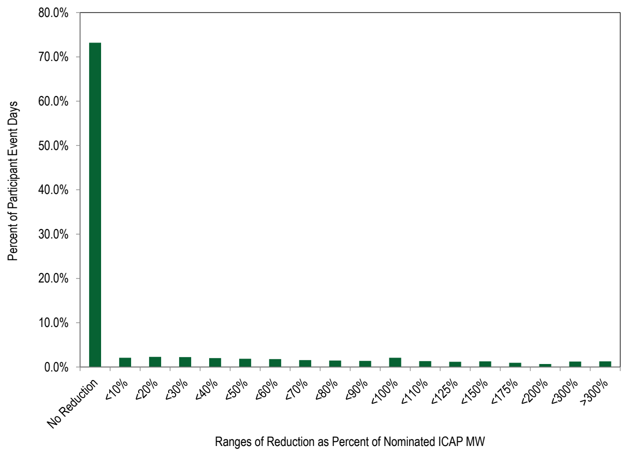
| Ranges of performance as a percentage of nominated ICAP MW | Number of participant event days | Proportion of participant event days | Nominated MW | Proportion of Nominated MW |
|---|---|---|---|---|
| 0%, load increase, or no reporting | 67,953 | 73.2% | 42,977 | 68.6% |
| 0% - 10% | 1,951 | 2.1% | 1,746 | 2.8% |
| 10% - 20% | 2,121 | 2.3% | 1,684 | 2.7% |
| 20% - 30% | 2,088 | 2.2% | 1,736 | 2.8% |
| 30% - 40% | 1,874 | 2.0% | 1,367 | 2.2% |
| 40% - 50% | 1,730 | 1.9% | 1,186 | 1.9% |
| 50% - 60% | 1,672 | 1.8% | 1,257 | 2.0% |
| 60% - 70% | 1,439 | 1.6% | 1,118 | 1.8% |
| 70% - 80% | 1,363 | 1.5% | 1,099 | 1.8% |
| 80% - 90% | 1,293 | 1.4% | 915 | 1.5% |
| 90% - 100% | 1,953 | 2.1% | 2,002 | 3.2% |
| 100% - 110% | 1,239 | 1.3% | 2,289 | 3.7% |
| 110% - 125% | 1,099 | 1.2% | 818 | 1.3% |
| 125% - 150% | 1,193 | 1.3% | 752 | 1.2% |
| 150% - 175% | 884 | 1.0% | 420 | 0.7% |
| 175% - 200% | 625 | 0.7% | 336 | 0.5% |
| 200% - 300% | 1,151 | 1.2% | 524 | 0.8% |
| > 300% | 1,198 | 1.3% | 381 | 0.6% |
| Total | 92,826 | 100.0% | 62,607 | 100.0% |

Figure 6-3 shows the data in Table 6-33.[34]

34 Participant event days, shown in Figure 6-3 shows the data in Table 6-33.

Figure 6-3, and Table 6-33, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant event day. The load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Figure 6-3 Distribution of participant event days across ranges of performance levels across the events: 2014




## Testing of Emergency Resources

Demand Resources must be tested if no emergency event is called in a specific zone for each product type. A provider's entire committed emergency Demand Resources in the same zone by the same type are required to test at the same time for a one hour period during any hour the product is required to be available for dispatch. For example, Limited DR must be called for a one hour period between 1200 (EPT) to 2000 (EPT) on a non-holiday weekday between June 1 and September 30. The CSP must notify PJM of the intent to test 48 hours in advance.[35]

Depending on initial test results, multiple tests may be conducted. If a CSP shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, none of the portfolio resources are eligible for a retest, and the CSP must pay a penalty. No CSP has ever paid a penalty for less than 75 percent compliance.

No Limited DR MW were dispatched during the compliance period for the 2014/2015 Delivery Year and thus all were required to perform testing.

The Limited DR product test results are shown in Table 6-34.[36] Overall test results showed a reported 9,388.2 MW load reduction, or 123.1 percent compliance and an observed 9,086.2 MW load reduction, or 119.8 percent compliance. The nominated MW exceeded the committed MW by 1,775.9 MW in the test zones, resulting in higher potential compliance.[37] Total testing penalties for Limited DR were $2.7 million for the 2014/2015 Delivery Year.

Load management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to a baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce load during a system emergency. Given prior warning of a test event, customers have time to prepare to drop load, unlike in a real emergency event in which a customer has had only 30 minutes to two hours notice before an event begins and will have only 30 minutes notice effective with the 2014/2015 Delivery Year. Customers can test on any day in the summer period between the hours of 1200 (EPT) and 2000 (EPT). The baseline day for Limited DR must occur within the limited demand response resource window of June 1 to October 1 to establish comparability between the baseline day and test day.

The MMU recommends that the testing program be modified to require verification of test methods and results. Tests should be initiated by PJM without prior scheduling by CSPs in order to more accurately model demand response during an emergency event.

35 For more information, see PJM, "Manual 18, PJM Capacity Market," Revision 27 (January 22, 2015), Section 8.6.

36 Extended Summer and Annual DR are not required to test unless there is no event during the entire delivery.

37 Committed MW are the cleared MW from the RPM by CSP.

Table 6-34 Load management test results and compliance by zone for the Limited product during the 2014/2015 Delivery Year

| Zone | Nominated ICAP (MW) | Committed MW | Load Reduction Reported (MW) | Load Reduction Observed (MW) | Difference (MW) | Percent Compliance Reported | Percent Compliance Observed |
|---|---|---|---|---|---|---|---|
| AECO | 100.0 | 45.9 | 61.1 | 60.4 | 0.7 | 133.1% | 131.6% |
| AEP | 1,570.2 | 1,273.1 | 1,673.1 | 1,630.2 | 42.8 | 131.4% | 128.1% |
| APS | 639.1 | 469.4 | 525.1 | 509.1 | 16.1 | 111.9% | 108.4% |
| ATSI | 776.8 | 660.2 | 878.9 | 800.0 | 78.8 | 133.1% | 121.2% |
| BGE | 767.2 | 693.8 | 1,369.4 | 1,361.1 | 8.4 | 197.4% | 196.2% |
| ComEd | 1,131.2 | 938.8 | 906.3 | 878.4 | 28.0 | 96.5% | 93.6% |
| DAY | 147.2 | 130.4 | 125.1 | 123.2 | 1.9 | 96.0% | 94.5% |
| DEOK | 278.7 | 252.6 | 296.0 | 292.8 | 3.2 | 117.2% | 115.9% |
| Dominion | 862.7 | 762.7 | 904.4 | 887.1 | 17.3 | 118.6% | 116.3% |
| DPL | 252.5 | 125.0 | 136.0 | 133.1 | 2.9 | 108.8% | 106.5% |
| DLCO | 97.6 | 78.9 | 84.0 | 81.1 | 2.9 | 106.4% | 102.7% |
| EKPC | 123.2 | 128.2 | 132.4 | 132.4 | 0.0 | 103.3% | 103.3% |
| JCPL | 147.1 | 126.3 | 156.8 | 151.3 | 5.5 | 124.1% | 119.8% |
| Met-Ed | 237.4 | 196.2 | 206.4 | 202.1 | 4.3 | 105.2% | 103.0% |
| PECO | 404.7 | 359.7 | 390.3 | 379.4 | 10.9 | 108.5% | 105.5% |
| PENELEC | 298.3 | 252.4 | 340.4 | 336.8 | 3.6 | 134.9% | 133.5% |
| Pepco | 548.2 | 181.1 | 257.8 | 250.0 | 7.8 | 142.4% | 138.1% |
| PPL | 620.9 | 533.6 | 554.9 | 545.2 | 9.7 | 104.0% | 102.2% |
| PSEG | 352.2 | 372.8 | 336.7 | 329.5 | 7.2 | 90.3% | 88.4% |
| RECO | 4.6 | 2.5 | 3.1 | 3.1 | 0.0 | 120.2% | 120.2% |
| Total | 9,359.6 | 7,583.7 | 9,338.2 | 9,086.2 | 252.0 | 123.1% | 119.8% |

## 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 calculated negative performance value. PJM limits compliance shortfall values at the nominated MW value for underperformance. This is not explicitly stated in the Tariff or supporting Manuals. According to the Tariff, the compliance formulas for FSL and GLD customers allow for negative compliance values.[38] 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, compliance for that registration is calculated as a 75 MWh load reduction for that event hour. 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 show a 0 MWh reduction in hour one and a 30 MWh reduction in hour two and an average hourly 15 MWh load reduction for that two hour event. Reported compliance is less than actual compliance, as locations with load increases, negative reductions, are treated as zero for compliance purposes. Overall, 73 percent of event hours demonstrated negative reductions or no reduction in load, as shown in Table 6-33.[39]

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 63.0 percent of locations were not submitted to PJM for compliance purposes. While the performance of these resources is not known, it is reasonable to assume, given the incentives to report reductions, that these locations had negative compliance (load increases relative to baseline), further skewing reported compliance values and performance penalties. Registrations with negative compliance are treated as zero for the purposes of imposing penalties and reporting.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated

38 PJM. OATT. PJM Emergency Load Response Program.

39 The demand response events that occurred in 2014 were all voluntary since they were outside the mandatory curtailment window of June 1, through September 30 from 1200 to 2000.

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 an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business but with a substantially reduced load can maintain their pre-bankruptcy FSL commitment which can be greater than or equal to the post-bankruptcy total load. 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. 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.

Table 6-35 shows the number of locations that did not report during the first three months of 2014 event days. In total, 63.0 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 60.1 percent of all nominated MW for those events. Response was voluntary as the only type of Emergency DR in existence at that time was Limited DR.

### Table 6-35 Non-reporting locations and nominated ICAP: 2014 event days

| | Locations Not Reporting | Percent Non Reporting | Nominated ICAP Not Reporting | Percent Non Reporting |
|---|---|---|---|---|
| Total | 58,443 | 63.0% | 37,627 | 60.1% |

## Emergency Energy Payments

For any PJM declared load management event in 2014, participants registered under the full option of the emergency load response program, which contains 99.6 percent of registrations, that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The emergency 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 new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800 per MWh. The maximum offer decreased to $1,599 per MWh for the 2014/2015 Delivery Year and will increase to $1,849 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[40 41]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-36 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2013/2014 Delivery Year. The majority of participants, 69.7 percent, have a minimum dispatch price of $1,000 per MWh, and 18.4 percent of participants have a dispatch price of $1,800 per MWh, which is the maximum price allowed for the 2013/2014 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2013/2014 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $500 to $800 strike prices had the highest average at $3,262.88 per location.

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 the emergency or economic demand response program.[42]

40 139 FERC ¶ 61,057 (2012).
41 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 from ER14-822-000.
42 PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014), p. 54.

### Table 6-36 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2013/2014 Delivery Year[43]

| Ranges of Strike Prices ($/MWh) | Locations | Percent of Total | Nominated MW (ICAP) | Percent of Total | Shutdown Cost per Location |
|---|---|---|---|---|---|
| $0-$1 | 538 | 3.6% | 861.0 | 9.6% | $0.00 |
| $1-$200 | 905 | 6.0% | 379.9 | 4.2% | $8.73 |
| $200-$500 | 216 | 1.4% | 186.9 | 2.1% | $141.90 |
| $500-$800 | 66 | 0.4% | 82.8 | 0.9% | $3,262.88 |
| $800-$999 | 67 | 0.4% | 50.8 | 0.6% | $520.37 |
| $1,000 | 10,499 | 69.7% | 5,926.0 | 66.1% | $26.05 |
| $1,800 | 2,776 | 18.4% | 1,479.5 | 16.5% | $0.00 |
| Total | 15,067 | 100.0% | 8,966.9 | 100.0% | $37.32 |

Table 6-37 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2014/2015 Delivery Year. The majority of participants, 94.7 percent, have a minimum dispatch price between $1,000 and $1,100 per MWh, and 0.1 percent of participants have a dispatch price between $1,276 and $1,549 per MWh, which is the maximum price allowed for the 2014/2015 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2014/2015 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $1,101 to $1,275 per MWh strike prices had the highest average at $160.05 per location.

### Table 6-37 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[44]

| Ranges of Strike Prices ($/MWh) | Locations | Percent of Total | Nominated MW (ICAP) | Percent of Total | Shutdown Cost per Location |
|---|---|---|---|---|---|
| $0-$1 | 570 | 3.6% | 630.0 | 6.7% | $0.00 |
| $1-$999 | 218 | 1.4% | 160.9 | 1.7% | $28.54 |
| $1,000-$1,100 | 15,101 | 94.7% | 7,497.1 | 80.1% | $72.88 |
| $1,101-$1,275 | 29 | 0.2% | 368.7 | 3.9% | $160.05 |
| $1,276-$1,549 | 21 | 0.1% | 703.6 | 7.5% | $66.67 |
| Total | 15,939 | 100.0% | 9,360.3 | 100.0% | $69.81 |

Table 6-38 includes the energy reduction MWh and average real time LMP during the eight demand response event days. The first column shows the hour beginning for each event day. The second column has the emergency demand response MWh reductions, which are calculated by comparing each resource's CBL to their actual load during the demand response event.[45] If a resource is registered for both the economic and emergency program, the economic CBL is used for the emergency CBL. If a resource is only registered under the emergency option, the CBL is the hour before the reductions occur.[46] On January 7, 2014, all demand response resources in the RTO were called at 430 to reduce at 530 and 630 EPT for short and long lead resources. If a resource could reduce before their designated lead time, that resource was eligible for energy settlements. The average LMP columns consist of the average LMP for each hour of an event day based on what zones were called. The January 22, 2014, event day included only SWMAAC, so the average LMP is the average of the BGE and Pepco zones. The LMP was only greater than $1,000 per MWh for the dispatched areas for three events, both of the January 7 events and the January 22 event.

43 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

44 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

45 This table assumes that PJM's CBL calculation is correct.

46 PJM has stated in the demand response subcommittee meeting, that when two events occurred in a single calendar day, that the hour before the first event is the CBL used for both events. If a resource does not submit for an energy settlement for the first event, the CBL would be the hour before the second event.

### Table 6-38 Energy reduction MWh and average real-time LMP during demand response event days: 2014

| | January 7, 2014 | | January 8, 2014 | | January 22, 2014 | | January 23, 2014 | | January 24, 2014 | | March 4, 2014 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour Beginning | MWh Reduction | Average LMP ($/MWh) | MWh Reduction | Average LMP ($/MWh) | MWh Reduction | Average LMP ($/MWh) | MWh Reduction | Average LMP ($/MWh) | MWh Reduction | Average LMP ($/MWh) | MWh Reduction | Average LMP ($/MWh) |
| 0 | | 321.5 | | 159.3 | | 60.7 | | 285.2 | | 382.0 | | 147.3 |
| 1 | | 416.4 | | 179.8 | | 160.4 | | 245.6 | | 445.6 | | 164.1 |
| 2 | | 422.7 | | 170.3 | | 185.7 | | 283.3 | | 520.1 | | 190.5 |
| 3 | | 277.8 | | 110.3 | | 153.2 | | 272.4 | | 468.0 | | 225.6 |
| 4 | 464.3 | 473.1 | | 119.7 | | 102.0 | 127.8 | 283.3 | 144.8 | 487.4 | 307.7 | 231.3 |
| 5 | 834.0 | 487.0 | 447.1 | 198.5 | | 404.7 | 233.9 | 203.9 | 217.6 | 618.6 | 575.3 | 847.6 |
| 6 | 1,359.8 | 1,030.5 | 902.7 | 328.6 | | 312.1 | 448.4 | 278.5 | 484.2 | 678.1 | 1,319.1 | 191.2 |
| 7 | 1,740.2 | 1,726.3 | 1,095.6 | 290.8 | | 557.7 | 620.2 | 348.3 | 578.0 | 833.6 | 1,763.9 | 199.4 |
| 8 | 1,981.7 | 1,832.7 | 911.1 | 184.3 | | 515.6 | 544.3 | 225.8 | 575.2 | 540.2 | 1,634.0 | 180.1 |
| 9 | 1,955.2 | 1,784.2 | | 213.5 | | 460.0 | | 123.7 | | 426.1 | | 239.9 |
| 10 | 1,799.9 | 1,772.1 | | 200.0 | | 503.0 | | 272.0 | | 361.1 | | 250.2 |
| 11 | | 1,434.3 | | 216.0 | | 513.8 | | 502.1 | | 278.2 | | 309.0 |
| 12 | | 406.3 | | 101.1 | | 462.9 | | 395.9 | | 294.7 | | 228.6 |
| 13 | | 495.8 | | 121.0 | | 274.8 | | 488.7 | | 313.4 | | 242.0 |
| 14 | | 327.6 | | 42.2 | 10.9 | 274.3 | 423.7 | 587.8 | | 250.9 | | 234.3 |
| 15 | 1,247.9 | 244.1 | | 96.4 | 37.6 | 1,206.8 | 588.0 | 565.7 | | 144.5 | | 186.4 |
| 16 | 1,802.5 | 291.6 | | 131.4 | 93.7 | 466.8 | 905.6 | 353.6 | | 207.0 | | 145.7 |
| 17 | 2,346.9 | 1,018.2 | | 182.0 | 108.0 | 1,818.6 | 930.7 | 476.7 | | 398.0 | | 210.4 |
| 18 | 2,227.9 | 437.8 | | 117.4 | 133.0 | 1,816.6 | 957.1 | 553.3 | | 283.3 | | 261.8 |
| 19 | | 438.0 | | 127.8 | 154.0 | 1,825.1 | | 623.1 | | 276.0 | | 192.8 |
| 20 | | 354.8 | | 156.1 | 159.3 | 1,749.3 | | 707.9 | | 396.0 | | 227.8 |
| 21 | | 258.8 | | 100.7 | | 592.7 | | 647.4 | | 371.2 | | 273.7 |
| 22 | | 215.3 | | 65.4 | | 469.6 | | 627.8 | | 144.9 | | 126.3 |
| 23 | | 211.2 | | 39.8 | | 358.7 | | 492.8 | | 230.4 | | 128.8 |
| Total | 17,760.0 | 694.9 | 3,356.4 | 152.2 | 696.6 | 635.2 | 5,779.7 | 410.2 | 1,999.7 | 389.6 | 5,600.0 | 234.8 |

Table 6-39 shows emergency revenue for each event day in 2014. Energy payments in the emergency program differ significantly from energy payments in the economic program and from capacity payments through the emergency load response program in that they are not based on or tied to any market price signal. Once an emergency demand response event is called for a zone or sub zone, payments are guaranteed if a resource is determined to have responded. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the Real-Time Energy Market.[47] Emergency demand response energy costs are not covered by LMP. All demand response energy payments and shutdown costs are out of market payments. These payments are a form of uplift.

The events on January 7, 2014, were the first voluntary events of 2014, and all resources in the RTO were called for both events. January 7 had the most MWh reductions and highest average LMP which resulted in the total emergency revenue of $22,691,122. The total emergency revenue for the voluntary emergency event days in 2014 were $42,971,731.

### Table 6-39 Emergency revenue by event: 2014

| Event Date | Total |
|---|---|
| January 7, 2014 | $22,691,122 |
| January 8, 2014 | $3,536,061 |
| January 22, 2014 | $1,210,678 |
| January 23, 2014 | $7,076,824 |
| January 24, 2014 | $2,637,138 |
| March 4, 2014 | $5,819,908 |
| Total | $42,971,731 |

## Limited Demand Resource Penalty Charge

Limited demand response resources are required to be available for only 10 times during the months of June through September in a delivery year on weekdays other than PJM holidays from 1200 (EPT) to 2000 (EPT) and be capable of maintaining an interruption for a minimum of two hours to a maximum of six hours. Limited demand response resources have one or two hours to reduce load once PJM initiates an event. When a provider under complies based on their committed MW, a daily penalty is charged. The penalty is based on the amount of under compliance, the number of

47 PJM. "Manual 28: Operating Agreement Accounting," Revision 68 (January 16, 2015), p 72.

events called during the DY and the cost per MW day for that provider. DR penalties are only assessed for PJM initiated events, after a compliance review is complete.

No penalties were assessed based on events that occurred during 2014, because all emergency events in 2014 were voluntary curtailment. The penalties increased by $15,817,614.31 from $2,037,700.10 in the 2012/2013 Delivery Year compared to $17,855,314.41 of the 2013/2014 Delivery Year. Table 6-40 shows penalty charges by zone for the 2012/2013 and 2013/2014 Delivery Year. The PECO Control Zone had the highest penalty amount, due to the clearing prices in EMAAC and a reported performance at 93.2 percent of the committed MW.[48] The penalty charges represent 3.3 percent of the capacity revenue for the 2013/2014 Delivery Year and 0.8 percent of the capacity revenue for the 2012/2013 Delivery Year.

There were no penalties for the 2014/2015 Delivery Year since there were no emergency events called and testing compliance was not completed at December 31, 2014.

### Table 6-40 Penalty charges per zone: 2012/2013 and 2013/2014 Delivery Years

| | 2012/2013 Penalty Charge | 2013/2014 Penalty Charge |
|---|---|---|
| AECO | $91.25 | $125,889.92 |
| AEP | $143,499.75 | $590,009.95 |
| AP | $0.00 | $0.00 |
| ATSI | $0.00 | $1,104,441.56 |
| BGE, Met-Ed, Pepco | $634,753.25 | $2,468,448.72 |
| ComEd | $0.00 | $0.00 |
| DAY | $0.00 | $0.00 |
| DEOK | $0.00 | $0.00 |
| Dominion | $59,020.50 | $310,907.51 |
| DPL | $740,756.55 | $766,832.39 |
| DLCO | $0.00 | $74,600.56 |
| EKPC | $0.00 | $0.00 |
| JCPL | $5,332.65 | $604,141.64 |
| PECO | $399,404.90 | $5,768,980.77 |
| PENELEC | $44,066.45 | $434,076.46 |
| PPL | $594.95 | $3,601,276.68 |
| PSEG, RECO | $10,179.85 | $2,005,708.25 |
| Total | $2,037,700.10 | $17,855,314.41 |

48 Refer to Section 5: Capacity, Table 5-11 for complete listing of capacity prices.