Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Economic program credits decreased by $836,828, from $9,284,118 in 2012 to $8,447,290 in 2013, a 9.0 percent drop. Emergency energy credits increased 250.4 percent to $36.7 million compared to 2012. In 2013, synchronized reserve credits for demand resources (DR) decreased by $1.3 million, or 29.7 percent, compared to 2012, from $4.5 million to $3.2 million in 2013.The capacity market is the primary source of revenue to participants in PJM demand response programs. In 2013, load management (LM) program revenue increased $98.8 million, or 29.9 percent, from $331.1 million in 2012 to $429.9 million in 2013. Demand response credits increased by $122.9 million or 34.6 percent to $478.3 million in 2013 compared to 2012.[1]

  Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Emergency demand response energy costs are not covered by LMP. All demand response energy payments are out of market; demand response payments are a form of uplift.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis when appropriate, but subzonal dispatches are only on a voluntary basis. Beginning with the 2014/2015 Delivery Year, demand resources will be 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.[2]

- **Emergency Event Day Analysis.** Emergency energy revenue increased by $26.2 million, or 250.4 percent, from $10.4 million in 2012 to $36.7 in 2013. Emergency load management event rules over-calculate a participants' compliance levels. Increases in load for dispatched demand resources, negative reduction MWh values, are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero. Considering all positive and negative reported values, the observed load reduction of the five events in 2013 should have been 4,807.8 MW, rather than the 5,488.5 MW calculated by PJM's method. The correct calculation of compliance is 81.8 percent rather than PJM's calculated 93.3 percent. This does not include locations that did not report their load during the emergency event days.

Recommendations

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program and not an emergency program.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[3]
- The MMU recommends that 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.[4]
- 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.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that demand resources measurement and verification be further modified to more accurately reflect compliance.

1 The total credits and MWh numbers for demand resources were calculated as of March 7, 2014 and may change as a result of continued PJM billing updates.

2 If "PJM Interconnection LLC," Docket No. ER14-822-000 (December 24, 2013) is approved by the FERC, mandatory curtailment for subzonal dispatch will be delayed until the 2015/2016 Delivery Year.

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

4 *Id* at 1.

- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE 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.[5]
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

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.

If retail markets reflected hourly wholesale prices and customers 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, 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 should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs. 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.

5 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 November 11, 2013) 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.

Table 6-1 Overview of demand response programs[6]

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
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.

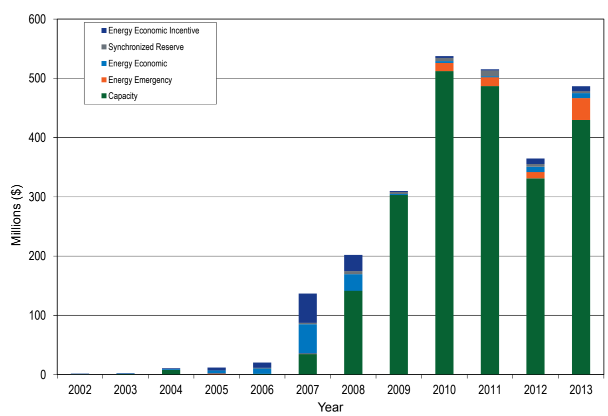
Participation in Demand Response Programs

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) is met. In 2013, credits and MWh in the economic program decreased compared to 2012, but increased compared to 2009, 2010 and 2011. There were fewer settlements submitted and fewer active participants in 2013 compared to 2012, and credits decreased.

Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through 2013. Since the implementation of the RPM design on June 1, 2007, the Capacity Market has been the primary source of revenue to demand response participants, representing 89.9 percent of all revenue received through demand response programs in 2013. In 2013, total credits under the economic program decreased by $836,828, from $9,284,118 in 2012 to $8,447,290 in 2013. This represents a 9.0 percent decrease in credits. In 2013, capacity revenue represented 89.9 percent of all revenue received by demand response providers, emergency energy revenue represented 7.7 percent, revenue from the economic program represented 1.8 percent and revenue from Synchronized Reserve represented 0.7 percent.

Capacity revenue increased by $98.8 million, or 29.9 percent, from $331.1 million in 2012 to $429.9 million in 2013, primarily due to higher clearing prices in the capacity market for the 2013/2014 Delivery Year. The emergency energy revenue increased by $26.2 million, or 250.4 percent, from $10.5 million in 2012 to $36.7 million in 2013. Emergency energy revenue increased in 2013 as a result of more emergency events called in PJM and an increased offer cap for demand response resources to $1,800 per MWh on June 1, 2013, from $1,000 per MWh. Synchronized reserve credits for demand response resources decreased by $1.3 million, from $4.5 million in 2012 to $3.2 million in 2013, due to lower clearing prices in the Synchronized Reserve Market.

Figure 6-1 Demand response revenue by market: 2002 through 2013



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period 2010 through 2013. The average number of registrations and registered MW increased in 2013. The average monthly registered MW for 2013 increased by 175 MW from 2,200 MW in 2012 to 2,375 MW in 2013. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations increased by 63 from

6 Prior to April 1, 2012, payment for the economic load response program was based on LMP minus the generation and transmission components of the retail rate.

1,071 in 2012 to 1,134 in 2013. The economic program's registered MW have not increased significantly with FERC Order No. 745.

There is a large overlap between economic registrations and emergency registrations. There were 811 registrations that were in both the economic and emergency programs. The registered MW in the economic load response program are not the amount of MW available for dispatch. Economic resources can dispatch more, less or the amount of MW registered in the program.

Table 6-2 Economic program registrations on the last day of the month: 2010 through 2013

	2010		2011		2012		2013	
Month	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	2,321
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,333
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,291
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,341
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,412
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,138
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,473
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,568
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,516
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,387
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,358
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,363
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,134	2,375

Table 6-3 Maximum economic MW dispatched by location per month: 2010 through 2013

	Maximum Dispatched MW by Location			
Month	2010	2011	2012	2013
Jan	233	243	104	193
Feb	121	190	101	119
Mar	115	153	72	127
Apr	111	80	108	133
May	172	98	143	192
Jun	209	561	944	431
Jul	999	561	1,641	1,088
Aug	794	161	980	497
Sep	276	84	451	517
Oct	118	81	242	157
Nov	111	86	165	151
Dec	41	88	99	158
Total	1,209	841	1,956	1,470

Since response by participants in the economic demand response program is optional, not all registrations or registered MW performed each year. Table 6-3 shows the maximum economic MW dispatched by location each month for 2010 through 2013. The maximum dispatched MW for each location were added together for each month to get the maximum economic MW dispatch value. Economic dispatch can occur above, at or below the registered MW amount for each registration. The total maximum MW by location dispatched in 2013 decreased by 485 MW, from 1,956 in 2012 to 1,470 in 2013. Total MW dispatched by location each year has grown with the implementation of FERC Order No. 745. The total MW dispatched by location in July of 2012 was the highest recorded for the last four years at 1,641 maximum MW dispatched by location.

Economic demand response energy costs are assigned to PJM market participants based on 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.[7] All demand response energy payments are out of market.

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by $2.47/MWh in 2013, from $64.02/MWh in 2012 to $66.49/MWh in 2013. Curtailed energy for the economic program was 127,045 MWh in 2013 and the total payments were $8,447,290. Credits for 2013 decreased by $836,828, or 13 percent, compared to 2012. Economic demand response resources that are dispatched in both the economic and emergency programs are settled under emergency rules. The five emergency events in 2013 reduced the economic load response credits in 2013 during the peak days in PJM.

7 PJM: "Manual 28: Operating Agreement Accounting," Revision 59 (April 22, 2013), p 70.

Table 6-4 Credits paid to the PJM economic program participants excluding incentive credits: 2003 through 2013

Year	Total MWh	Total Credits	$/MWh
2003	19,518	$833,530	$42.71
2004	58,352	$1,917,202	$32.86
2005	157,421	$13,036,482	$82.81
2006	258,468	$10,213,828	$39.52
2007	714,148	$31,600,046	$44.25
2008	452,222	$27,087,495	$59.90
2009	57,157	$1,389,136	$24.30
2010	74,070	$3,088,049	$41.69
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	127,045	$8,447,290	$66.49

Figure 6-2 shows monthly economic demand response credits, for 2009 through 2013. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. For the months of June through August, total economic demand response credits decreased by $2,506,945 from $6,764,613 in 2012 to $4,257,946 in 2013. Both 2012 and 2013 had more economic demand response credits than 2009 through 2011.

Figure 6-2 Economic program credits by month: 2009 through 2013

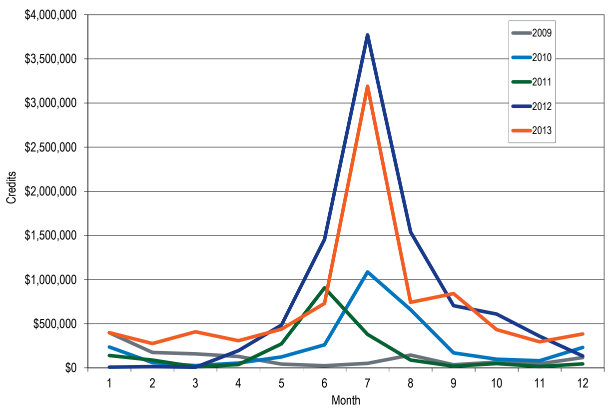


Table 6-5 shows 2012 and 2013 performance in the economic program by control zone and participation type. The Dominion Control Zone accounted for $4,822,827 or 60 percent of all economic program credits, associated with 80,243 MWh or 60.5 percent of total program reductions. The Dominion Control Zone had the highest average MW reductions per registration and average credits per registration.

Table 6-5 PJM Economic program participation by zone: 2012 and 2013[8]

	Credits			MWh Reductions		
Zones	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO, JCPL, PECO, RECO	$884,993	$519,152	(41%)	10,869	3,934	(64%)
AP	$1,068,328	$216,693	(80%)	16,825	3,637	(78%)
AEP, ATSI, ComEd, DAY, DEOK, DLCO, EKPC, PENELEC	$975,265	$1,132,313	16%	17,963	21,342	19%
BGE, DPL, Met-Ed, Pepco	$542,522	$670,416	24%	6,013	3,657	(39%)
Dominion	$4,215,114	$5,113,549	21%	65,688	84,199	28%
PPL	$441,458	$269,602	(39%)	5,076	3,545	(30%)
PSEG	$1,156,438	$525,566	(55%)	22,586	6,731	(70%)
Total	$9,284,118	$8,447,290	(9%)	145,019	127,045	(12%)

Table 6-6 shows total settlements submitted by year for 2008 through 2013. A settlement is counted for every day on which a registration is dispatched in the economic program. Settlements submitted by year in the economic program have decreased from 2008 to 2013. Settlements increased after FERC Order No. 745 in 2012, but decreased in 2013. There were 4,002 less settlements in 2013 than in 2012.

Table 6-6 Settlements submitted by year in the economic program: 2008 through 2013

	2008	2009	2010	2011	2012	2013
Total	32,990	21,605	12,697	4,591	7,894	3,897

Table 6-7 shows the number of distinct curtailment service providers (CSPs) and distinct participants actively submitting settlements by year for the period 2009 through 2013. The number of active participants during 2013 decreased by 229 compared to 2012. The smaller number of active participants in 2013 responded more frequently compared to participants in 2012.

Table 6-7 Distinct participants and CSPs submitting settlements in the Economic Program by year: 2009 through 2013

	2009		2010		2011		2012		2013	
	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	25	747	24	438	20	610	24	520	22	291

Table 6-8 Hourly frequency distribution of economic program MWh reductions and credits: 2012 and 2013

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2012	2013	Percentage Change	2012	2013	Percentage Change
1	177	168	(5%)	$5,326	$5,867	10%
2	176	156	(12%)	$3,997	$4,009	0%
3	179	144	(20%)	$2,316	$3,226	39%
4	220	136	(38%)	$2,413	$2,377	(1%)
5	227	136	(40%)	$3,338	$2,406	(28%)
6	291	236	(19%)	$6,834	$7,783	14%
7	3,112	5,673	82%	$145,453	$313,467	116%
8	4,635	6,792	47%	$205,997	$400,083	94%
9	5,166	7,036	36%	$200,227	$327,904	64%
10	4,849	6,553	35%	$190,280	$292,944	54%
11	4,477	4,910	10%	$204,828	$229,059	12%
12	5,113	4,434	(13%)	$267,238	$199,568	(25%)
13	8,256	6,635	(20%)	$572,564	$356,923	(38%)
14	12,638	10,174	(19%)	$818,401	$855,745	5%
15	16,987	13,681	(19%)	$1,208,146	$1,014,289	(16%)
16	18,217	14,232	(22%)	$1,460,337	$1,164,466	(20%)
17	18,766	14,221	(24%)	$1,489,493	$1,182,457	(21%)
18	18,373	13,441	(27%)	$1,314,136	$1,010,531	(23%)
19	9,196	10,131	10%	$541,938	$627,836	16%
20	6,522	4,686	(28%)	$335,446	$257,863	(23%)
21	3,736	2,060	(45%)	$179,181	$119,957	(33%)
22	2,044	827	(60%)	$79,851	$43,898	(45%)
23	942	345	(63%)	$27,631	$14,921	(46%)
24	718	240	(67%)	$18,746	$9,713	(48%)
Total	145,019	127,045	(12%)	$9,284,118	$8,447,290	(9%)

Table 6-8 shows MWh reductions and credits in each hour for 2012 and 2013. In 2013, 43.7 percent of the reductions occurred between hour ending 1500 and hour ending 1800, while in 2012, 49.9 percent of hourly reductions occurred during those hours. The majority of reductions occurred between hours ending 1000 and hour ending 1800.

8 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

Following the implementation of FERC Order No. 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during the hours they were dispatched, provided that LMP was greater than the net benefits test threshold. The NBT is used to define a price point above which the net benefits of DR are deemed to exceed the cost to load. When the LMP is above the NBT threshold, the demand response resource receives credit for the full LMP. The net benefits test defined an average price of $28.09 for 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the net benefits test price.

Table 6-9 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP.

Total economic program reductions decreased by 17,974 MWh, from 145,019 MWh in 2012 to 127,045 MWh in 2013. Reductions occurred at all price levels. Approximately 80.5 percent of MWh reductions and 58.0 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. MWh reductions in 2013 decreased 12.4 percent compared to 2012.

Table 6-9 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2012 and 2013

	MWh Reductions			Program Credits		
LMP	2012	2013	Percentage Change	2012	2013	Percentage Change
$0 to $25	1,676	362	(78.4%)	$8,893	$13,361	50.2%
$25 to $50	80,848	75,985	(6.0%)	$3,069,793	$3,190,964	3.9%
$50 to $75	31,388	26,237	(16.4%)	$1,905,190	$1,706,528	(10.4%)
$75 to $100	11,427	7,290	(36.2%)	$1,002,933	$690,586	(31.1%)
$100 to $125	6,711	6,293	(6.2%)	$788,302	$860,996	9.2%
$125 to $150	4,179	4,278	2.4%	$568,642	$660,723	16.2%
$150 to $200	2,995	2,483	(17.1%)	$505,094	$395,878	(21.6%)
$200 to $250	3,028	1,905	(37.1%)	$628,775	$324,872	(48.3%)
$250 to $300	1,829	851	(53.5%)	$471,562	$221,550	(53.0%)
> $300	939	1,363	45.1%	$334,934	$381,831	14.0%
Total	145,019	127,045	(12.4%)	$9,284,118	$8,447,290	(9.0%)

Emergency Program

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 a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources. This will ensure comparability and consistency for demand resources. The MMU also recommends demand resources have an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently at $1,000 per MWh.[9]

Table 6-10 shows zonal monthly capacity credits to demand resources for 2013. Capacity revenue increased in 2013 by $98.8 million, or 29.9 percent, compared to 2012, from $331.1 million to $429.9 million due to higher RPM prices and more DR participation in RPM for the 2013/2014 Delivery Year.[10]

9 See "Complaint and Motion to Consolidate of the Independent Market Monitor," Docket No. EL14-20-000 (January 28, 2014).

10 For more detail on RPM prices see the *2013 State of the Market Report for PJM*, Volume II, Section 5, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml>.

Table 6-10 Zonal monthly capacity credits: 2013

Zone	January	February	March	April	May	June	July	August	September	October	Novemeber	December	Total
AECO	$411,097	$371,313	$411,097	$397,836	$411,097	$1,002,307	$1,035,717	$1,035,717	$1,002,307	$1,035,717	$257,721	$1,035,717	$8,407,643
AEP, EKPC	$425,101	$383,962	$425,101	$411,388	$425,101	$751,158	$776,197	$776,197	$751,158	$776,197	$1,145,576	$776,197	$7,823,329
AP	$185,478	$167,528	$185,478	$179,495	$185,478	$477,348	$493,260	$493,260	$477,348	$493,260	$749,663	$493,260	$4,580,855
ATSI	$19,859	$17,937	$19,859	$19,218	$19,859	$365,564	$377,750	$377,750	$365,564	$377,750	$477,348	$377,750	$2,816,205
BGE	$5,430,108	$4,904,613	$5,430,108	$5,254,943	$5,430,108	$7,487,232	$7,736,807	$7,736,807	$7,487,232	$7,736,807	$365,564	$7,736,807	$72,737,134
ComEd	$405,926	$366,643	$405,926	$392,831	$405,926	$782,114	$808,185	$808,185	$782,114	$808,185	$7,487,232	$808,185	$14,261,452
DAY	$63,670	$57,508	$63,670	$61,616	$63,670	$42,849	$44,278	$44,278	$42,849	$44,278	$782,114	$44,278	$1,355,058
DEOK	$8,185	$7,393	$8,185	$7,921	$8,185	$16,115	$16,653	$16,653	$16,115	$16,653	$42,849	$16,653	$181,557
DLCO	$49,718	$44,907	$49,718	$48,114	$49,718	$143,269	$148,045	$148,045	$143,269	$605,391	$16,115	$605,391	$2,051,701
Dominion	$306,929	$277,226	$306,929	$297,028	$306,929	$585,863	$605,391	$605,391	$585,863	$1,979,013	$585,862	$1,979,013	$8,421,436
DPL	$1,547,049	$1,397,335	$1,547,049	$1,497,145	$1,547,049	$1,915,174	$1,979,013	$1,979,013	$1,915,174	$148,045	$1,915,174	$148,045	$17,535,265
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,447,382	$1,495,628	$2,215,048	$2,288,883	$2,288,883	$2,215,048	$2,288,883	$1,495	$2,288,883	$20,872,275
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,010,595	$1,044,281	$2,174,111	$2,246,581	$2,246,581	$2,174,111	$2,246,581	$2,215,048	$2,246,581	$20,636,256
PECO	$2,660,069	$2,402,643	$2,660,069	$2,574,260	$2,660,069	$5,142,792	$5,314,219	$5,314,219	$5,142,792	$5,314,219	$2,174,111	$5,314,219	$46,673,680
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,107,926	$1,144,857	$2,884,571	$2,980,723	$2,980,723	$2,884,571	$2,980,723	$5,142,792	$2,980,723	$28,411,388
Pepco	$1,906,591	$1,722,082	$1,906,591	$1,845,088	$1,906,591	$4,092,964	$4,229,396	$4,229,396	$4,092,964	$4,229,396	$2,884,571	$4,229,396	$37,275,024
PPL	$3,247,272	$2,933,020	$3,247,272	$3,142,521	$3,247,272	$7,019,745	$7,253,736	$7,253,736	$7,019,745	$7,253,736	$4,092,964	$7,253,736	$62,964,755
PSEG	$2,354,400	$2,126,555	$2,354,400	$2,278,452	$2,354,400	$8,574,172	$8,859,978	$8,859,978	$8,574,172	$8,859,978	$7,019,745	$8,859,978	$71,076,209
RECO	$14,896	$13,454	$14,896	$14,415	$14,896	$249,408	$257,721	$257,721	$249,408	$257,721	$249,408	$257,721	$1,851,664
Total	$22,721,111	$20,522,294	$22,721,111	$21,988,172	$22,721,111	$45,921,805	$47,452,531	$47,452,531	$45,921,805	$47,452,531	$37,605,354	$47,452,531	$429,932,888

Table 6-11 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 and 2013/2014 Delivery Year. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources increased by 63 percent from 631.2 MW in 2012/2013 to 1,029.2 MW in 2013/2014 Delivery Year.

Table 6-11 Energy efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
	2012/ 2013	2013/ 2014	Percentage Change	2012/ 2013	2013/ 2014	Percentage Change
Total	609.8	990.9	62%	631.2	1,029.2	63%

Table 6-12 shows the MW registered by measurement and verification method and by load drop method. Of the DR MW committed, 5.5 percent use the guaranteed load drop (GLD) measurement and verification method, 86.5 percent use firm service level (FSL) method and 8.0 percent use direct load control (DLC).

Table 6-12 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	Percentage by type
Firm Service Level	1,887.0	2,164.1	289.3	857.5	3,487.9	123.7	253.0	9,062.5	86.5%
Guaranteed Load Drop	77.1	287.1	1.2	145.9	44.9	0.9	18.8	575.9	5.5%
Non hourly metered sites (DLC)	0.0	770.4	0.0	0.0	0.0	68.9	0.0	839.2	8.0%
Total	1,964.1	3,221.5	290.5	1,003.4	3,532.8	193.5	271.9	10,477.7	100.0%
Percentage by method	18.7%	30.7%	2.8%	9.6%	33.7%	1.8%	2.6%	100.0%	

The program type is submitted as "Other" for 2.6 percent of committed MW, which does not explain how the reduction occurs. The choice of other is no longer a valid option for new registrations as of the 2014/2015 Delivery Year.

Table 6-13 shows the fuel type used in the on-site generators identified in Table 6-12. Of the 18.7 percent of emergency demand response identified as using on-site generation, 81.8 percent of MW are diesel, 5.2 percent are natural gas and 12.9 percent is coal, oil, other or no fuel source.[11]

Table 6-13 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal, Oil, Other	16.5	0.8%
Diesel	1,606.7	81.8%
Natural Gas	102.9	5.2%
None	238.0	12.1%
Total	1,964.0	100.00%

11 Since 2.6 percent of committed MW are registered under the other option, the 18.7 percent of emergency load response resources registered with on-site generation could be conservatively low.

Emergency Event Reported Compliance

In 2013, PJM declared five emergency events in the 2013/2014 Delivery Year, on July 15, July 16, July 18, September 10 and September 11. There were two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of these events occurred within the summer compliance period, all were considered in PJM's compliance assessment. Table 6-14 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 6.7 percent of capacity resources in the 2013/2014 Delivery Year.

Table 6-14 Demand response cleared MW UCAP for PJM: 2011/2012 through 2013/2014 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%

Table 6-15 lists PJM emergency load management events declared by PJM in 2013 and the affected zones. The ATSI Control Zone was called for all five events.

The emergency demand response program currently settles 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.

Table 6-15 PJM declared load management events: 2013

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical Area
15-Jul-13	15:50-18:22	16:00-18:00	32	Long Lead	ATSI
16-Jul-13	13:30-16:30	14:00-16:00	60	Long Lead	ATSI
18-Jul-13	14:40-18:00	15:00-18:00	20	Long Lead	ATSI
	14:40-17:00	15:00-17:00	20	Long Lead	PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	AEP Canton Subzone
10-Sep-13	15:50-21:30	16:00-20:00	100	Long Lead	ATSI
	16:45-21:30	17:00-20:00	115	Long Lead	AEP Canton Subzone
11-Sep-13	13:30-19:30	14:00-19:00	60	Long Lead	AEP
	14:00-20:00	14:00-20:00	0	Long Lead	ATSI
	14:00-17:15	14:00-17:00	15	Short Lead	AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC Pepco, PPL, PSEG, RECO
	14:30-18:30	15:00-18:00	60	Long Lead	Dominion
	15:00-17:00	15:00-17:00	0	Long Lead	AECO, JCPL, PSEG, RECO
	15:00-17:30	15:00-17:30	30	Long Lead	Met-Ed, PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	BGE, DPL, Pepco
	15:00-18:30	15:00-18:00	30	Long Lead	PENELEC, DLCO

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 99.4 percent of registrations, accounting for 91.7 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.

There were two events in 2013, on July 18, 2013 and September 10, 2013, for which PJM requested voluntary subzonal dispatch of emergency demand side resources. While PJM may voluntarily declare load management events for part of a zone, the only locational requirement for the aggregation of multiple participants to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal emergency events is aggregated for each CSP to a zonal level.

Subzonal dispatch by zip code is currently voluntary, but will be mandatory beginning with the 2014/2015 delivery year.[12] 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.

12 If PJM Interconnection L.L.C., Docket No. ER14-822-000 (December 24, 2013) is approved by the FERC, the mandatory requirement for subzonal dispatch will be delayed until the 2015/2016 Delivery Year.

PJM ignores load increases from demand resources when calculating response and compliance. PJM calculates compliance for demand response events by reducing increases in load, negative compliance values, during an event to a zero MW reduction. 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 the negative reduction value and instead replaces the value 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.[13] 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.

Table 6-16 shows the performance for the July 15, 2013, event. The first column shows the nominated value, which is the reduction capability indicated by the participant at registration. The second column shows load management committed MW, which are used to assess RPM compliance. Differences between these two columns reflect, in part, differences between MW offered and cleared for any partially cleared DR. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for demand resources, while the nominated ICAP does not. The third column shows the reported load reduction in MWh, or the reported load drop during the hours of an event. The reported reduction does not include negative reductions, load increases. The reported reduction is as reported by PJM. The fourth column shows the observed load reduction in MWh, which includes all reported reduction values. The observed load reduction is as calculated by the MMU.

Table 6-16 Load management event performance: July 15, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	795.7	683.1	670.8	535.3	135.5	98.2%	78.4%
Total	795.7	683.1	670.8	535.3	135.5	98.2%	78.4%

Table 6-17 Load management event performance: July 16, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	795.7	683.1	637.9	519.7	118.2	93.4%	76.1%
Total	795.7	683.1	637.9	519.7	118.2	93.4%	76.1%

The ATSI Control Zone was called for the event on July 15, 2013. Overall, the PJM reported performance was 98.2 percent, or 670.8 MW out of 683.1 MW committed. The observed performance level was 78.4 percent compliance or 592.2 MW, a difference of 135.5 MW compared to the reported load reduction.

Table 6-17 shows the performance for the July 16, 2013, event. The ATSI Control Zone was called for the event on July 16, 2013. Overall, the PJM reported performance was 93.4 percent, or 637.9 MW out of 683.1 MW committed. The observed performance level was 76.1 percent compliance or 519.7 MW, a difference of 118.2 MW compared to the reported load reduction.

The ATSI Control Zone reduced 15.6 MW less on the July 16 event day compared to the July 15 event day. This reduction is consistent with the hypothesis that the response of demand resources declines when demand response events are called on successive days.

Table 6-18 shows the performance for the July 18, 2012 event. The ATSI, PECO, PPL and AEP Canton subzone zones were called for the event on July 18, 2013. Overall, the PJM reported performance was 93.3 percent, or 1,558.8 MW out of 1,671.7 MW committed. The observed performance level was 83.6 percent compliance or 1,396.9 MW, a difference of 161.9 MW compared to the reported load reduction. The ATSI and PECO zones had 88.9 and 92.2 percent reported compliance. The PPL Control Zone had 99.1 percent reported compliance. The AEP Canton subzone dispatch was not mandatory.

This was the third event for ATSI Control Zone during this week, and the compliance results decreased from an observed 535.3 MW reduction on July 15, 2013, to an observed 519.7 MW reduction on July 16 and an observed 519.5 MW reduction on July 18, 2013.

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

Table 6-18 Load management event performance: July 18, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	796.2	683.1	607.3	519.5	87.8	88.9%	76.1%
PECO	580.0	410.1	378.2	331.3	46.9	92.2%	80.8%
PPL	751.5	578.5	573.4	546.1	27.3	99.1%	94.4%
Total	2,127.7	1,671.7	1,558.8	1,396.9	161.9	93.3%	83.6%

Table 6-19 shows the performance for the September 10, 2013 event. The ATSI and AEP Canton subzone zones were called for the event on September 10, 2013. Overall, the PJM reported performance was 94.1 percent, or 642.5 MW out of the 683.1 MW committed. The observed performance level was 77.9 percent compliance or 532.0 MW, a difference of 110.5 MW compared to the reported load reduction. The AEP Canton subzone dispatch was not mandatory. The event continued past the mandatory compliance period and the hourly data past the compliance period do not count towards the compliance value for PJM. After 2000 (EPT), limited demand response is considered voluntary curtailment.

This was the fourth event in the ATSI Control Zone and the second call for the AEP Canton subzone. The compliance results increased from an observed 519.5 MW reduction on July 18, 2013, to an observed 532.0 MW on September 10.

Table 6-19 Load management event performance: September 10, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	799.4	683.1	642.5	532.0	110.5	94.1%	77.9%
Total	799.4	683.1	642.5	532.0	110.5	94.1%	77.9%

Table 6-20 shows the performance for the September 11, 2013 event. The AECO, AEP, ATSI, BGE, DLCO, Dominion, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO zones were called for the event on September 11, 2013. Overall, the PJM reported performance was 92.7 percent, or 5,623.7 MW out of the 6,064.9 MW committed. The observed performance level was 82.7 percent compliance or 5,017.0 MW, a difference of 606.7 MW compared to the reported load reduction. The short lead time resources covered three zones; Met-Ed, PENELEC, and RECO, that did not have any short lead time resources.

The BGE Control Zone performed at 107.3 percent observed compliance, or 672.7 MW. BGE has 787.7 nominated MW to cover their 627.2 committed MW obligation, resulting in the 107.3 percent observed compliance. The BGE Control Zone's performance compared to the committed MW level increased the overall compliance measured for all zones without BGE from 79.9 percent observed compliance to 82.7 percent observed compliance with BGE.

This was the fifth call in the ATSI Control Zone for the 2013/2014 Delivery Year, and its performance decreased to the lowest for all the events at 68.4 percent observed compliance, or 467.2 MW.

Table 6-20 Load management event performance: September 11, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	114.7	102.5	91.8	86.4	5.4	89.6%	84.3%
AEP	1,576.0	1,252.0	1,243.0	1,131.3	111.7	99.3%	90.4%
ATSI	800.0	683.1	601.4	467.2	134.2	88.0%	68.4%
BGE	787.7	627.2	690.3	672.7	17.6	110.1%	107.3%
BGE Long Lead	715.3	565.6	617.9	600.4	17.6	109.2%	106.1%
BGE Short Lead	72.4	61.6	72.4	72.4	0.0	117.5%	117.5%
DLCO	91.7	69.2	54.3	49.4	4.8	78.4%	71.4%
Dominion	863.1	757.0	683.0	621.4	61.6	90.2%	82.1%
DPL	250.7	220.3	221.8	208.2	13.7	100.7%	94.5%
DPL Long Lead	178.7	154.4	119.2	105.5	13.7	77.2%	68.3%
DPL Short Lead	72.0	65.9	102.7	102.7	0.0	155.8%	155.8%
JCPL	191.0	156.7	145.3	83.4	61.9	92.7%	53.2%
JCPL Lead Lead	171.1	136.8	120.3	58.4	61.9	87.9%	42.7%
JCPL Short Lead	19.9	19.9	25.0	25.0	0.0	125.6%	125.6%
Met-Ed	231.2	173.6	180.0	167.5	12.5	103.5%	96.3%
PECO	563.7	410.3	328.6	276.7	51.9	80.1%	67.4%
PENELEC	322.3	265.1	259.6	236.1	23.5	97.9%	89.1%
Pepco	700.2	372.0	304.9	294.9	10.0	82.0%	79.3%
Pepco Long Lead	203.9	200.3	160.8	150.8	10.0	80.3%	75.3%
Pepco Short Lead	496.3	171.7	144.1	144.1	0.0	83.9%	83.9%
PPL	790.2	621.1	611.7	565.6	46.1	98.5%	91.1%
PPL Long Lead	742.9	578.5	548.0	501.8	46.1	94.7%	86.8%
PPL Short Lead	47.2	42.6	63.8	63.8	0.0	149.6%	149.6%
PSEG	377.9	350.6	203.3	152.4	50.8	58.0%	43.5%
PSEG Long Lead	364.6	346.1	198.4	157.7	40.7	57.3%	45.6%
PSEG Short Lead	13.3	4.4	4.9	(5.3)	10.2	110.9%	(120.0%)
RECO	6.4	4.0	4.8	3.8	1.0	118.1%	93.5%
Total	7,666.7	6,064.9	5,623.7	5,017.0	606.7	92.7%	82.7%

Table 6-21 shows load management event performance for the five event days. RTO wide percent reported compliance was 93.3 percent in 2013 for resources called during emergency events, while observed compliance was 81.8 percent. The reported performance value treated locations showing increases in load, negative performance, as zero performance. The BGE Control Zone reported 110.1 percent compliance and observed 107.3 percent compliance were the highest in PJM, while the DLCO Control Zone observed 71.4 percent compliance and the JCPL Control Zone observed 53.2 percent observed compliance were the lowest.

The BGE Control Zone over performed by 45.5 MW which offset under performance in other zones. The observed compliance for all zones, excluding BGE, was 78.8 percent of the committed MW. The ATSI Control Zone had five calls and had an average 75.4 percent observed compliance. The JCPL Control Zone only had one event called during 2013, and had 53.2 percent observed compliance. Every zone underperformed compared to their nominated ICAP MW. CSPs have more MW registered than are committed in each zone to ensure deliverability at the committed MW level.

Table 6-21 Load management event performance: 2013 Aggregated

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	114.7	102.5	91.8	86.4	5.4	89.6%	84.3%
AEP	1,576.0	1,252.0	1,243.0	1,131.3	111.7	99.3%	90.4%
ATSI	797.4	683.1	625.8	514.7	111.1	91.6%	75.4%
BGE	787.7	627.2	690.3	672.7	17.6	110.1%	107.3%
DLCO	91.7	69.2	54.3	49.4	4.8	78.4%	71.4%
Dominion	863.1	757.0	683.0	621.4	61.6	90.2%	82.1%
DPL	250.7	220.3	221.8	208.2	13.7	100.7%	94.5%
JCPL	191.0	156.7	145.3	83.4	61.9	92.7%	53.2%
Met-Ed	231.2	173.9	180.0	167.5	12.5	103.5%	96.3%
PECO	571.8	410.3	353.4	304.0	49.4	86.1%	74.1%
PENELEC	322.3	265.1	259.6	236.1	23.5	97.9%	89.1%
Pepco	700.2	372.0	304.9	294.9	10.0	82.0%	79.3%
PPL	770.8	621.5	592.5	555.8	36.7	95.4%	89.5%
PSEG	377.9	350.6	203.3	152.4	50.8	58.0%	43.5%
RECO	6.4	4.0	4.8	3.8	1.0	118.1%	93.5%
Weighted Total	7,652.9	6,064.9	5,660.7	4,958.7	571.7	93.3%	81.8%

Table 6-22 Distribution of participant event days and nominated MW across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period

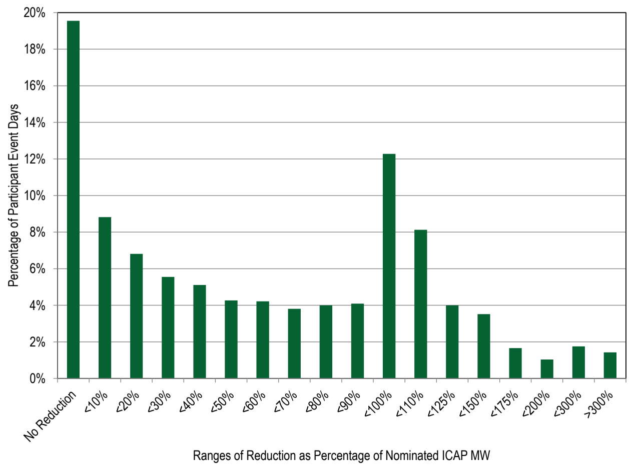
Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of Nominated MW
0%, load increase, or no reporting	2,974	20%	1,102	9%
0% - 10%	1,342	9%	790	6%
10% - 20%	1,036	7%	909	7%
20% - 30%	844	6%	435	4%
30% - 40%	777	5%	376	3%
40% - 50%	649	4%	323	3%
50% - 60%	641	4%	331	3%
60% - 70%	579	4%	523	4%
70% - 80%	608	4%	332	3%
80% - 90%	622	4%	479	4%
90% - 100%	1,868	12%	875	7%
100% - 110%	1,236	8%	3,411	28%
110% - 125%	608	4%	1,194	10%
125% - 150%	535	4%	631	5%
150% - 175%	252	2%	243	2%
175% - 200%	157	1%	155	1%
200% - 300%	267	2%	138	1%
> 300%	217	1%	136	1%
Total	15,212	100%	12,383	100%

Performance for specific customers varied significantly. Table 6-22 shows the distribution of participant event days across various levels of performance for July 15, July 16, July 18, September 10 and September 11, 2013, events in the 2013/2014 compliance period. Table 6-22 includes the participation for subzonal and zonal dispatch. For these events, 20 percent of participant event days showed no reduction, load increased or participants did not report data. Approximately 50 percent of participant event days provided less than half of their nominated MW, while 32 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, approximately 78 percent, provided less than 100 percent reduction compared to their nominated MW, while 52 percent of the nominated MW provided less than 100 percent reduction.

Figure 6-3 shows the data in Table 6-22.[14] The distribution includes high frequencies of both under performing and over performing registrations.

14 Participant event days, shown in Figure 6-3 shows the data in Table 6-22. The distribution includes high frequencies of both under performing and over performing registrations. Figure 6-3, and Table 6-22, 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 event in the 2013/2014 Delivery Year compliance period



Testing of Emergency Resources

Load management must be tested if no emergency event is called in a specific zone by August 15 of the delivery year. All of a provider's committed emergency demand response resources in the same zone are required to test at the same time for a one hour period between 1200 (EPT) to 2000 (EPT) on a non-holiday weekday between June 1 and September 30. The resource provider must notify PJM of the intent to test 48 hours in advance.[15]

Depending on initial test results, multiple tests may be conducted. If a curtailment service provider (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, no associated resources are eligible for a retest.

Table 6-23 Load management test results and compliance by zone for the 2013/2014 Delivery Year

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AP	1,375.8	511.2	1,241.9	1,209.6	32.3	242.9%	236.6%
ComEd	2,439.0	810.6	2,119.6	2,105.1	14.5	261.5%	259.7%
DAY, DEOK, EKPC	416.6	185.3	330.5	324.5	6.0	178.4%	175.1%
Total	4,359.4	1,623.8	3,970.9	3,927.4	43.5	244.5%	241.9%

There were 1,623.8 committed MW not deployed in an event during the compliance period for the 2013/2014 Delivery Year and thus required to perform testing. Load management test results are shown in Table 6-23. Overall test results showed an observed 3,927.4 MW load reduction, or 241.9 percent compliance. There were an additional 2,735.6 MW nominated in the test zones compared to the committed MW, allowing for a higher potential compliance.

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 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 will only have one to two hours' notice before an event begins. Customers can test on any day in the summer period between the hours of 1200 (EPT) and 2000 (EPT). The baseline day 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.

15 For more information, see PJM, "Manual 18, PJM Capacity Market," Revision 20 (November 21, 2013), Section 8.6.

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. Load management event rules allow 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 within registrations or a demand response portfolio. For example, if a registration had two locations, one with a 50 MWh load increase, and another with a 75 MWh load reduction, compliance for that registration is calculated at 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, 14 percent of event hours demonstrated negative reductions or no reduction in load.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 6.8 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.

Table 6-24 shows the number of locations that did not report during 2013 event days. In total, 6.8 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 3.2 percent of all nominated MW for those events. It is likely that these locations were not responding to the emergency event and had loads greater than their committed MW for those locations, and the corresponding registrations.

Table 6-24 Non-reporting locations and nominated ICAP on 2013 event days

	Locations Not Reporting	Percent Non Reporting	Nominated ICAP Not Reporting	Percent Non Reporting
Total	1,231	6.8%	420	3.2%

Emergency Energy Payments

For any PJM declared load management event in 2013, participants registered under the full option of the emergency load response program 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 increases to $2,100 per MWh for the 2014/2015 Delivery Year and $2,700 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[16]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-25 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices. The majority of participants, 65.9 percent, have a minimum dispatch price of $1,000 per MWh, 1.5 percent of participants have a dispatch price of $1,001 per MWh to $1,799 per MWh and 17.7 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) recently approved changes in Manual 15 to eliminate shutdown costs for demand response resources participating in the

16 139 FERC ¶ 61,057 (2012).

Synchronized Reserve Market, but not the emergency or economic demand response program.[17]

Table 6-25 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices effective for the 2013/2014 Delivery Year[18]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	694	4.7%	1,036.5	9.8%	$0.00
$1-$200	1,204	8.2%	539.3	5.1%	$409.39
$200-$500	179	1.2%	107.2	1.0%	$171.23
$500-$800	66	0.4%	84.0	0.8%	$3,262.88
$800-$999	56	0.4%	52.9	0.5%	$622.59
1000	9,719	65.9%	6,685.6	63.1%	$28.14
$1,001-$1,799	219	1.5%	250.0	2.4%	$879.68
1800	2,619	17.7%	1,833.4	17.3%	$0.00
Total	14,756	100.0%	10,588.9	100.0%	$84.03

Table 6-26 shows emergency credits for each event in 2013 by zone. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market.[19] 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.

LMP in the ATSI Control Zone was $1,705.04 per MWh on average during the July 18, 2013, event, resulting in total emergency demand response costs in the ATSI Control Zone of $1.8 million. Total emergency credits for the emergency event days were $36,730,878.23.

Table 6-26 Emergency credits by event by zone: 2013

Event	Zone	Total
15-Jul-13	ATSI	$1,599,802.92
16-Jul-13	ATSI	$1,827,507.29
18-Jul-13	AEP	$696,926.40
	ATSI	$1,766,836.50
	PECO	$1,374,163.36
	PPL	$2,185,842.11
10-Sep-13	AEP	$845,091.99
	ATSI	$878,740.70
11-Sep-13	AECO	$209,208.82
	AEP	$9,166,436.46
	ATSI	$838,112.95
	BGE	$3,666,790.23
	DLCO	$259,868.34
	Dominion	$2,804,228.14
	DPL	$684,296.56
	JCPL	$315,112.76
	Met-Ed	$884,050.38
	PECO	$1,606,267.08
	PENELEC	$1,144,191.49
	Pepco	$639,505.99
	PPL	$2,622,194.49
	PSEG	$704,086.18
	RECO	$11,617.09
Total		$36,730,878.23

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 event is called in a zone, these payments are guaranteed if a resource is determined to have responded.

17 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.

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

19 PJM. "Manual 28: Operating Agreement Accounting," Revision 59 (April 22, 2013), p. 65.

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 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 penalty is charged. The penalty is based on the amount of under compliance, the number of 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.

Subzonal dispatch was voluntary, so there were no penalties assessed based on the AEP Canton Subzone dispatch. The penalties are assessed daily and have increased by $6,371,193.23 from $1,194,706.36 in June through December of the 2012/2013 Delivery Year compared to $7,565,899.59 of the same period in the 2013/2014 Delivery Year. Table 6-27 shows penalty charges by zone for June through September of 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.[20] The penalty charges represent 2.4 percent of the capacity credits for the 2013/2014 Delivery Year and 0.8 percent of the capacity credits for the 2012/2013 Delivery Year.

Table 6-27 Penalty charges per zone: June through September 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$53.50	$47,916.54
AEP	$84,134.10	$217,538.25
AP	$0.00	$0.00
ATSI	$0.00	$501,318.87
BGE, Met-Ed, Pepco	$372,156.70	$909,172.89
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$34,603.80	$113,197.17
DPL	$434,306.58	$284,574.63
DLCO	$0.00	$28,433.82
EKPC	$0.00	$0.00
JCPL	$3,126.54	$220,683.18
PECO	$234,171.64	$2,747,982.66
PENELEC	$25,836.22	$159,393.87
PPL	$348.82	$1,571,637.36
PSEG, RECO	$5,968.46	$764,050.35
Total	$1,194,706.36	$7,565,899.59

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