Demand Response (DR)

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.** In the first nine months of 2013, total load reduction under the Economic Load Response Program decreased by 7,002 MWh compared to the same period in 2012, from 121,381 MWh in the first nine months of 2012 to 114,379 MWh in the first nine months of 2013, a six percent decrease. Total credits under the Economic Program decreased by $1,084,448, from $8,172,654 in the first nine months of 2012 to $7,088,205 in the same period of 2013, a 13 percent decrease. September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day.

  The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first nine months of 2013, Load Management (LM) Program revenue increased $33.8 million, or 12.8 percent, compared to the same period of 2012, from $263.6 million to $297.4 million in 2013.

  In the first nine months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.9 million, or 54.2 percent, compared to the same period in 2012, from $3.6 million to $1.6 million in 2013.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate, but only on a voluntary basis. Beginning with the 14/15 Delivery Year, demand resources will be dispatchable on a subzonal basis, defined by zip codes. More locational deployment of demand-side resources improves efficiency in a nodal market.

- **Load Management Product.** The load management product is currently defined as an emergency product. The load management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.

- **Emergency Event Day Analysis.** Load management event rules allow over compliance to be reported when there is no actual over compliance. Settlement MWh are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero even if load actually increases. Considering all and only reported values, the observed load reduction of the five events in 2013 should have been 5,116.9 MW, rather than the 5,644.7 MW reported. Overall, compliance decreases from the reported 100.5 percent to 90.6 percent. This does not include locations that did not report their load during the emergency event days.

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

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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. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[1] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and receives the market clearing price. The load management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.[2]

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.

1 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."
2 This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. 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. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event. The MMU also 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 DR resources are based on actual metered data.[3]

PJM Demand Response Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 6-1 provides an overview of the key features of PJM load response programs.[4]

Table 6-1 Overview of Demand Side Programs[5]

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.

3 ISO-NE requires that DR resource 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. See Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response."
4 For more detail on the historical development of PJM Load Response Programs see the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.
5 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.

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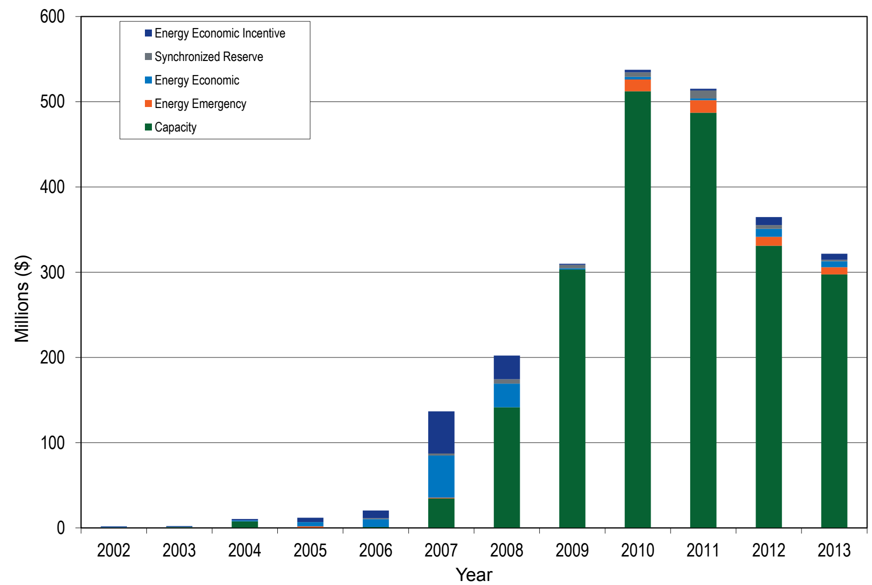
Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In the first nine months of 2013, in the Economic Program, participation decreased compared to the same period in 2012. There were fewer settlements submitted and fewer active participants in the first nine months of 2013 compared to the same period in 2012, and credits decreased. September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day.

Figure 6-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first nine months of 2013. Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to demand side participants, representing 94.6 percent of all revenue received through demand response programs in the first nine months of 2013. In the first nine months of 2013, total credits under the Economic Program decreased by $1,084,448, from $8,172,654 in the first nine months of 2012 to $7,088,205 in the same period of 2013. This represents a 13 percent decrease in credits. The total MWh reductions decreased by seven percent for the first seven months of 2013 compared to the first seven months of 2012. In the first nine months of 2013, capacity revenue represents 94.6 percent of all revenue received by demand response providers, emergency energy revenue represented 2.7 percent, revenue from the economic program represented 2.3 percent and revenue from Synchronized Reserve represented 0.5 percent.

Capacity revenue increased by $33.8 million, or 12.8 percent, from $263.7 million to $297.4 million in the first nine months of 2013, primarily due to higher clearing prices in the RPM market for the 2013/2014 Delivery Year. Synchronized Reserve credits for demand side resources decreased by $1.9 million, from $3.6 million to $1.6 million in the first nine months 2013, due to lower clearing prices in the Synchronized Reserve market.

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



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period 2010 through the first nine months of 2013. The average registered MW for the first nine months increased by 202 MW from 2,175 in 2012 to 2,377. Historically, registered MW have declined in June but have increased in August, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Although registrations decreased, total registered MW were higher by 1,815 MW in the first nine months of 2013 compared to the same period of 2012. The registered MW per registration increased in the first nine months of 2013 compared to the first nine months of 2012. The average number of active registrations was 1,150 in the first nine months of 2012 and 1,113 in the same period in 2013.

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Table 6-2 Economic Program registrations on the last day of the month: 2010 through September 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		
Nov	1,605	2,444	1,988	2,255	824	2,267		
Dec	1,598	2,439	1,992	2,259	846	2,283		
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,113	2,377

Total credits in Table 6-3 exclude incentive credits in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[6]

Table 6-3 Performance of PJM Economic Program participants excluding incentive credits: 2003 through September 2013

Year	Total MWh	Total Credits	$/MWh
2009 (Jan-Sep)	45,424	$1,160,957	$25.56
2010 (Jan-Sep)	58,280	$2,677,937	$45.95
2011 (Jan-Sep)	15,376	$1,943,507	$126.40
2012 (Jan-Sep)	120,070	$8,149,477	$67.87
2013 (Jan-Sep)	114,379	$7,088,205	$61.97

6 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

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Figure 6-2 shows monthly economic program credits, excluding incentive credits, for 2009 through September 2013. Higher energy prices and FERC Order 745 increased incentives to participate during the first nine months of 2013. During the peak summer months of June through August, total Economic Demand Response credits decreased by $2,506,945 from $6,764,613 in June through August of 2012 to $4,257,946 in the same period of 2013. September 2013 data do not yet reflect complete economic program activity results as participants have up to 60 days to submit data for settlement.

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

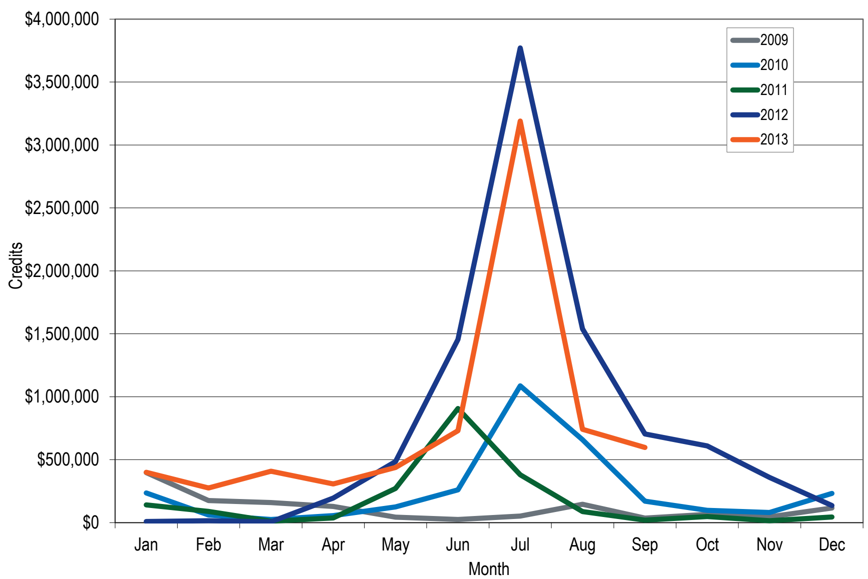

Table 6-4 shows the first nine months of 2012 and 2013 performance in the Economic Program by control zone and participation type. Curtailed energy for the Economic Program was 114,379 MWh and the total payment amount was $7,088,205. The Dominion Control Zone accounted for $4,079,022 or 58 percent of all Economic Program credits, associated with 66,847 MWh or 58 percent of total program reductions. Table 6-4 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion Control Zone has the highest average MW reductions per customer and average credits per customer. Credits for the first nine months of 2013 decreased by $1,084,448, or 13 percent, compared to the same time period of 2012. However, this does not fully account for data lag in September settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total credits decreased by three percent from the first seven months of 2012 compared to the first seven months of 2013.

Table 6-4 PJM Economic Program participation by zone: January through September 2012 and 2013

	Credits			MWh Reductions		
	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO	$20,555	$19,459	(5%)	98	143	46%
AEP	$13,272	$27,648	108%	172	939	445%
AP	$933,407	$164,594	(82%)	14,000	2,579	(76%)
ATSI	$9,034	$24,612	172%	110	8,094	7,251%
BGE	$181,086	$642,144	255%	1,005	3,416	240%
ComEd	$434,132	$612,568	41%	7,541	12,445	65%
DAY	$0	$0	NA	0	0	NA
DEOK	$0	$60,279	NA	0	986	NA
DLCO	$3,032	$0	(100%)	44	0	(100%)
Dominion	$3,503,563	$4,079,022	16%	51,442	66,847	30%
DPL	$37,698	$18,315	(51%)	280	117	(58%)
EKPC	$0	$0	NA	0	0	NA
JCPL	$244,640	$404,022	65%	2,062	2,467	20%
Met-Ed	$203,409	$9,643	(95%)	2,830	110	(96%)
PECO	$589,933	$85,781	(85%)	7,875	2,322	(71%)
PENELEC	$420,885	$273,935	(35%)	7,967	4,722	(41%)
Pepco	$118,789	$5	(100%)	1,051	0	(100%)
PPL	$448,208	$267,310	(40%)	4,845	4,884	1%
PSEG	$1,011,011	$398,867	(61%)	20,060	4,309	(79%)
RECO	$0	$0	NA	0	0	NA
Total	$8,172,654	$7,088,205	(13%)	121,381	114,379	(6%)

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Table 6-5 shows total settlements submitted by month for 2008 through September 2013. July of 2012 had 1,761 more settlement days compared to July of 2013. September does not include all of the settlement days because of the 60 day lag.

Table 6-5 Settlement days submitted by month in the Economic Program: 2008 through September 2013

Month	2008	2009	2010	2011	2012	2013
Jan	2,916	1,264	1,415	562	62	192
Feb	2,811	654	546	148	30	92
Mar	2,818	574	411	82	46	126
Apr	3,406	337	338	102	93	160
May	3,336	918	673	298	144	189
Jun	3,184	2,727	1,221	743	1,480	402
Jul	3,339	2,879	3,010	1,412	2,906	1,145
Aug	3,848	3,760	2,158	793	1,693	573
Sep	3,264	2,570	660	294	555	491
Oct	1,977	2,361	699	66	481	
Nov	1,105	2,321	672	51	280	
Dec	986	1,240	894	40	124	
Total	32,990	21,605	12,697	4,591	7,894	3,370

Table 6-6 shows the number of distinct Curtailment Service Providers (CSPs) and distinct participants actively submitting settlements by month for the period 2009 through September 2013.[7] The number of active participants during the first nine months of 2013 decreased by 217 compared to the same period in 2012. The smaller number of active customers in 2013 responded more frequently compared to customers in the same period of 2012.

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

	2009		2010		2011		2012		2013	
Month	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Jan	17	257	11	153	5	40	5	15	8	47
Feb	12	129	9	92	6	29	3	9	5	14
Mar	11	149	7	124	3	15	3	12	5	19
Apr	9	76	5	77	3	15	3	8	5	16
May	9	201	6	140	6	144	5	20	6	33
Jun	20	231	11	152	10	304	16	338	9	53
Jul	21	183	18	267	15	214	21	383	17	215
Aug	15	400	14	317	14	186	17	361	12	67
Sep	11	181	11	96	7	47	11	127	15	149
Oct	11	93	8	37	3	9	9	50		
Nov	9	143	7	38	3	13	5	63		
Dec	10	160	7	44	5	12	3	10		
Total Distinct Active	25	747	24	438	20	610	24	520	22	288

7 September credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

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Table 6-7 shows a frequency distribution of MWh reductions and credits in each hour for the first nine months of 2012 and 2013. In the first nine months of 2013, 50.6 percent of the reductions occurred between hour ending 15 and hour ending 18, while in the first nine months of 2012, 54.8 percent of hourly reductions occurred during those hours.

Table 6-7 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 2012 and 2013

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2012	2013	Percentage Change	2012	2013	Percentage Change
1	141	152	8%	$4,124	$5,101	24%
2	142	140	(1%)	$3,514	$3,303	(6%)
3	142	140	(2%)	$1,733	$2,520	45%
4	134	139	4%	$137	$1,683	NA
5	135	145	7%	$673	$1,687	NA
6	201	152	(24%)	$3,304	$3,592	9%
7	960	3,616	277%	$31,493	$192,380	511%
8	2,028	4,353	115%	$56,806	$266,427	369%
9	2,828	4,440	57%	$92,999	$213,000	129%
10	3,020	4,382	45%	$112,694	$194,191	72%
11	3,557	3,771	6%	$159,326	$180,371	13%
12	4,314	3,614	(16%)	$228,530	$162,849	(29%)
13	7,489	5,756	(23%)	$533,585	$304,535	(43%)
14	11,625	9,727	(16%)	$775,030	$776,812	0%
15	15,992	14,052	(12%)	$1,157,989	$908,191	(22%)
16	17,074	15,316	(10%)	$1,415,885	$1,044,855	(26%)
17	17,026	15,377	(10%)	$1,420,189	$1,045,575	(26%)
18	16,416	13,173	(20%)	$1,245,547	$879,634	(29%)
19	7,353	9,374	27%	$448,900	$541,560	21%
20	4,860	3,890	(20%)	$229,341	$212,163	(7%)
21	2,684	1,410	(47%)	$135,777	$87,057	(36%)
22	1,822	701	(62%)	$73,886	$38,162	(48%)
23	828	330	(60%)	$24,813	$13,735	(45%)
24	609	229	(62%)	$16,379	$8,820	(46%)
Total	121,381	114,379	(6%)	8,172,654	7,088,205	(13%)

Following the implementation of Order 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 (NBT) 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 $27.50 from January through September 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test price.

Table 6-8 shows the frequency distribution of Economic Program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP.

Total Economic Program reductions decreased by 7,002 MWh, from 121,381 MWh in the first nine months of 2012 to 114,379 MWh in the same time period of 2013. Reductions occurred at all price levels. Approximately 71.5 percent of MWh reductions and 54.4 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. MWh reductions in the first nine months of 2013 decreased 5.8 percent compared to the same period in 2012. However, the 2013 data is not fully representative of activity in September due to the lag in settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total MWh reductions decreased by seven percent from the first seven months of 2013 compared to the first seven months of 2012.

Table 6-8 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 2012 and 2013

	MWh Reductions			Program Credits		
LMP	2012	2013	Percentage Change	2012	2013	Percentage Change
$0 to $25	1,433	525	(64.8%)	$8,893	$13,361	50.2%
$25 to $50	62,853	58,721	(6.6%)	$2,382,790	$2,431,227	2.0%
$50 to $75	28,105	23,008	(18.1%)	$1,714,893	$1,423,356	(17.0%)
$75 to $100	10,722	8,447	(21.2%)	$936,533	$583,971	(37.6%)
$100 to $125	6,048	8,112	34.1%	$711,440	$789,421	11.0%
$125 to $150	3,925	4,980	26.9%	$534,845	$614,937	15.0%
$150 to $200	2,677	2,237	(16.4%)	$459,682	$346,071	(24.7%)
$200 to $250	2,927	3,296	12.6%	$616,602	$300,421	(51.3%)
$250 to $300	1,777	781	(56.1%)	$471,389	$203,610	(56.8%)
> $300	914	4,272	367.5%	$335,585	$381,831	13.8%
Total	121,381	114,379	(5.8%)	$8,172,654	$7,088,205	(13.3%)

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Load Management Program

Table 6-9 shows zonal monthly capacity credits to DR resources for the period January through September of 2013. Capacity revenue increased in the first nine months of 2013 by $33.8 million, or 12.8 percent, compared to the first nine months of 2012, from $263.7 million to $297.4 million in part due to higher RPM price increases for the 2013/2014 Delivery Year.[8]

Table 6-9 Zonal monthly capacity credits: January through September 2013

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$411,097	$371,313	$411,097	$397,836	$411,097	$1,002,307	$1,035,717	$1,035,717	$1,002,307	$6,078,488
AEP	$425,101	$383,962	$425,101	$411,388	$425,101	$749,663	$774,652	$774,652	$749,663	$5,119,282
AP	$185,478	$167,528	$185,478	$179,495	$185,478	$477,348	$493,260	$493,260	$477,348	$2,844,672
ATSI	$19,859	$17,937	$19,859	$19,218	$19,859	$365,564	$377,750	$377,750	$365,564	$1,583,358
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	$56,897,957
ComEd	$405,926	$366,643	$405,926	$392,831	$405,926	$782,114	$808,185	$808,185	$782,114	$5,157,850
DAY	$63,670	$57,508	$63,670	$61,616	$63,670	$42,849	$44,278	$44,278	$42,849	$484,388
DEOK	$8,185	$7,393	$8,185	$7,921	$8,185	$16,115	$16,653	$16,653	$16,115	$105,403
DLCO	$49,718	$44,907	$49,718	$48,114	$49,718	$143,269	$148,045	$148,045	$143,269	$824,803
Dominion	$306,929	$277,226	$306,929	$297,028	$306,929	$585,863	$605,391	$605,391	$585,863	$3,877,548
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	$15,324,002
EKPC	$0	$0	$0	$0	$0	$1,495	$1,544	$1,544	$1,495	$6,078
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	$16,293,015
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	$13,928,045
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	$33,871,131
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	$17,307,149
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	$25,931,661
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	$44,364,319
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	$46,336,509
RECO	$14,896	$13,454	$14,896	$14,415	$14,896	$249,408	$257,721	$257,721	$249,408	$1,086,813
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	$297,422,472

8 For more detail on RPM prices see the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

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Table 6-10 shows the amount of Energy Efficiency resources in each LDA for the 2012/2013 and 2013/2014 Delivery Year. 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 6-10 LDA Energy Efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
LDA Name	2012/2013	2013/2014	Percentage Change	2012/2013	2013/2014	Percentage Change
DPL-SOUTH	0.0	12.4	NA	0.0	12.9	NA
EMAAC	18.7	17.3	(7%)	19.0	17.1	(10%)
MAAC	44.3	81.1	83%	45.7	83.9	84%
Pepco	0.0	74.6	NA	0.0	77.5	NA
PS-NORTH	6.6	10.4	58%	6.8	10.8	59%
PSEG	6.1	13.1	115%	6.1	13.3	118%
RTO	395.5	593.5	50%	410.0	617.5	51%
SWMAAC	138.6	188.5	36%	143.6	196.2	37%
Total	609.8	990.9	62%	631.2	1,029.2	63%

Table 6-11 shows the MW registered by measurement and verification method and by load drop method. Of the DR MW committed, 3.5 percent use the Guaranteed Load Drop measurement and verification method, 86.9 percent use Firm Service Level method and 9.6 percent use Direct Load Control.

The load drop method is labeled as Other for 3.6 percent of committed MW. The MMU recommends that any MW designated as Other explicitly record the method of load drop.

Table 6-12 shows the fuel type used in the on-site generators identified in Table 6-11. Of the load management resources identified as using on-site generation, 80.6 percent of MW are diesel, 5.5 percent are natural gas and 13.8 percent is coal, oil, other or no fuel source.

Table 6-11 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	1,766.7	1,371.9	242.1	698.1	3,311.3	91.8	258.0	7,739.9	86.9%
Guaranteed Load Drop	62.0	165.8	4.1	23.0	33.9	0.7	23.8	313.4	3.5%
Non hourly metered sites (DLC)	0.0	775.6	0.0	0.0	0.0	40.0	37.0	852.6	9.6%
Total	1,828.7	2,313.4	246.1	721.1	3,345.2	132.6	318.8	8,905.9	100.0%
Percentage by method	20.5%	26.0%	2.8%	8.1%	37.6%	1.5%	3.6%	100.0%	

Table 6-12 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal	1.0	0.1%
Diesel	1,474.4	80.6%
Natural Gas	101.2	5.5%
None	236.8	12.9%
Oil	8.7	0.5%
Other	6.6	0.4%
Total	1,828.7	100.00%

Load Management Event Reported Compliance

In the first nine months of 2013, PJM declared five Load Management events, 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. These events affected resources committed for the 2013/2014 Delivery Year. Since each of these events occurred within the summer compliance period, each was considered in compliance assessment. Table 6-13 has the Demand Response cleared UCAP MW per zone by Delivery Year. Total Demand Response cleared in PJM increased from 1.4 percent in the 2011/2012 Delivery Year to 6.7 percent in the 2013/2014 Delivery Year.

Table 6-14 lists Load Management Events declared by PJM in the first nine months of 2013 and the affected zones. ATSI was the only zone called for all five events.

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. 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. The nominal ICAP stated in event compliance tables here will not equal total nominal ICAP for the zone, as not all resources were called in each zone during the events. Approximately 99.5 percent of registrations, accounting for 91.8 percent of registered MW, are designated as long lead time resources.

Table 6-13 Demand Response Cleared MW UCAP by Zone: 2011/2012 through 2013/2014 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
Zone	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
AECO	28.9	1.6%	128.0	6.6%	184.5	9.3%
AEP	120.5	1.7%	926.6	13.1%	996.6	11.8%
AP	130.4	1.3%	541.7	5.1%	667.6	6.6%
ATSI	31.1	90.7%	128.5	23.1%	565.0	4.6%
BGE	671.5	12.7%	1,326.7	20.9%	1,126.9	17.4%
ComEd	127.8	0.5%	970.5	4.0%	985.1	3.7%
DAY	17.5	0.7%	127.1	5.0%	59.6	2.7%
DEOK	NA	NA	62.1	5.4%	88.2	7.6%
DLCO	15.6	0.5%	110.2	4.1%	194.5	6.9%
Dominion	112.3	0.5%	680.6	2.9%	744.1	3.2%
DPL	56.5	1.3%	323.5	7.1%	302.4	6.5%
EKPC	NA	NA	NA	NA	12.3	3.0%
JCPL	60.8	1.6%	346.2	8.3%	308.6	7.2%
Met-Ed	27.9	0.7%	277.2	6.7%	340.1	7.6%
PECO	115.0	1.2%	652.5	6.0%	720.7	6.5%
PENELEC	23.5	0.3%	307.9	4.0%	471.0	6.0%
PEPCO	161.6	2.8%	467.7	8.7%	661.9	11.4%
PPL	81.2	0.8%	842.3	7.4%	1,131.0	9.6%
PSEG	44.2	0.4%	517.8	4.6%	1,185.0	9.9%
RECO	0.3	100.0%	3.8	100.0%	34.5	100.0%
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%

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Table 6-14 PJM declared Load Management Events: 2013

Event Date	Event Times	Compliance Hours	Minutes not counted	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

There were two events in 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 end use customers 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 zipcode is currently voluntary but will be mandatory beginning with the 2014/2015 delivery year. 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.

Table 6-15 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 MW commitments, 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 resource. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not, although resources fully buying out of their commitments are not included in this analysis. The third column shows the observed load reduction in MWh, or the reported load drop during the hours of an event.

Overall, the reported performance was 97.5 percent, or 672.7 MW out of 690.0 MW committed. This reported performance value treated locations showing negative performance or non-reporting as zero performance.

Table 6-15 Load Management event performance: July 15, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	810.7	690.0	672.7	(17.3)	97.5%	83.0%
Total	810.7	690.0	672.7	(17.3)	97.5%	83.0%

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Table 6-16 shows the performance for the July 16, 2013, event. ATSI was the only zone called for this event. The reported performance was 91.4 percent, or 630.7 MW out of 690.0 MW committed. This reported performance value treated locations showing negative performance or non-reporting as zero performance.

Table 6-16 Load Management event performance: July 16, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	802.2	690.0	630.7	(59.3)	91.4%	78.6%
Total	802.2	690.0	630.7	(59.3)	91.4%	78.6%

Table 6-17 shows the performance for the July 18, 2012 event. Overall, the performance was 92.8 percent, or 1,645.0 MW out of 1,772.2 MW committed. The ATSI and PECO Zones had 87.4 and 82.6 percent compliance. This was the third event for ATSI during this week, and the compliance results decreased from an observed 672.7 MWh reduction on July 15, 2013, to an observed 630.7 MWh reduction on July 16 and an observed 603.1 MWh reduction on July 18, 2013. The AEP Canton Subzone dispatch was not mandatory, but the subzone performed at 100.6 percent compliance with 93.8 MW out of 93.2 MW committed. This reported performance value treated locations showing negative performance as zero performance.

Table 6-17 Load Management event performance: July 18, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	797.7	690.0	603.1	(86.9)	87.4%	75.6%
PECO	733.2	410.1	338.6	(71.6)	82.6%	46.2%
PPL	791.8	578.8	609.6	30.7	105.3%	77.0%
AEP Canton Subzone	129.4	93.2	93.8	0.6	100.6%	72.5%
Total	2,452.1	1,772.2	1,645.0	(127.2)	92.8%	67.1%

Table 6-18 Load Management event performance: September 10, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
ATSI	808.8	690.0	597.0	(93.0)	86.5%	73.8%
AEP Canton Subzone	129.4	93.2	55.1	(38.1)	59.1%	42.6%
Total	938.2	783.2	652.1	(131.1)	83.3%	69.5%

Table 6-18 shows the performance for the September 10, 2013 event. The event continued past the mandatory compliance period and the hourly data past the compliance period does not count towards the compliance value for PJM. This was the fourth event in the ATSI zone and the zone delivered 86.5 percent of its committed MW, or 597.0 MW. The AEP Canton Subzone delivered 59.1 percent of its committed MW, or 55.1 MW. This was the second call for the subzone, and it was not mandatory based on the current PJM rules for the 2013/2014 Delivery Year.

Table 6-19 shows the performance for the September 11, 2013 event. The Short Lead call covered three zones, Met-Ed, Penelec, and RECO, that did not have any Short Lead resources. This was the fifth call in the ATSI Zone, and its performance decreased to the lowest for all the events at 84.5 percent compliance, or 582.9 MW. The Short Lead resources in the PPL Zone only had 0.3 MW nominated out of the 42.6 MW committed. The 0.3 MW performed during the event, but the compliance for PPL's short lead resources was only 0.7 percent. AEP and DPL's Short Lead resources over performed at 158.1 percent and 158.8 percent compliance.

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Table 6-19 Load Management event performance: September 11, 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	126.3	102.5	95.7	(6.8)	93.3%	75.7%
AECO Long Lead	84.5	50.7	53.8	3.2	106.2%	63.7%
AECO Short Lead	41.8	51.8	41.8	(10.0)	80.7%	100.0%
AEP	1,660.0	830.2	1,312.1	481.9	158.1%	79.0%
ATSI	826.0	690.0	582.9	(107.1)	84.5%	70.6%
BGE	860.0	627.2	697.3	70.1	111.2%	81.1%
BGE Long Lead	787.6	565.6	625.0	59.3	110.5%	79.3%
BGE Short Lead	72.4	61.6	72.4	10.8	117.5%	100.0%
DLCO	113.2	69.2	48.9	(20.3)	70.7%	43.2%
Dominion	877.3	751.7	672.9	(78.8)	89.5%	76.7%
DPL	302.2	220.3	231.4	11.1	105.0%	76.6%
DPL Long Lead	230.2	154.4	126.7	(27.7)	82.1%	55.0%
DPL Short Lead	72.0	65.9	104.7	38.8	158.8%	145.5%
JCPL	210.2	156.7	140.6	(16.1)	89.7%	66.9%
JCPL Lead Lead	190.3	136.8	113.4	(23.5)	82.9%	59.6%
JCPL Short Lead	19.9	19.9	27.2	7.3	136.9%	136.7%
Met-Ed	238.0	173.6	182.8	9.2	105.3%	76.8%
Met-Ed Long Lead	238.0	173.6	182.8	9.2	105.3%	76.8%
Met-Ed Short Lead	0.0	0.0	0.0	NA	NA	NA
PECO	591.4	410.3	301.4	(109.0)	73.4%	51.0%
PECO Long Lead	591.2	410.1	301.3	(108.9)	73.5%	51.0%
PECO Short Lead	0.2	0.2	0.1	(0.1)	64.5%	61.9%
Penelec	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Penelec Long Lead	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Penelec Short Lead	0.0	0.0	0.0	NA	NA	NA
Pepco	495.2	371.9	252.2	(119.7)	67.8%	50.9%
Pepco Long Lead	305.1	200.3	189.2	(11.1)	94.5%	62.0%
Pepco Short Lead	190.2	171.7	63.1	(108.6)	36.7%	33.2%
PPL	762.2	621.5	557.7	(63.8)	89.7%	73.2%
PPL Long Lead	761.9	578.8	557.4	(21.5)	96.3%	73.2%
PPL Short Lead	0.3	42.6	0.3	(42.3)	0.7%	100.0%
PSEG	475.2	350.6	277.0	(73.6)	79.0%	58.3%
PSEG Long Lead	470.1	346.1	271.8	(74.3)	78.5%	57.8%
PSEG Short Lead	5.0	4.4	5.1	0.7	116.5%	102.2%
RECO	6.4	4.0	4.8	0.7	118.0%	73.9%
RECO Long Lead	6.4	4.0	4.8	0.7	118.0%	73.9%
RECO Short Lead	0.0	0.0	0.0	NA	NA	NA
Total	**7,885.5**	**5,644.7**	**5,596.8**	**(47.9)**	**99.2%**	**71.0%**

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Table 6-20 shows load management event performance for the five event days. RTO wide percent reported compliance was 100.5 percent in 2013 for resources called during emergency events. This reported performance value treated locations showing negative performance as zero performance. AEP's over performance by 481.9 MW offset under compliance in other zones. The compliance for all zones, excluding AEP, was 90.5 percent of the committed MW. The ATSI Zone had five calls and ended with an average of 88.7 percent compliance. The Pepco Zone only had one call and had 67.8 percent compliance. Every zone underperformed compared to their Nominal ICAP MW. CSPs have to register more MW than are committed in each zone to be able to deliver at the committed MW level.

Table 6-20 Load Management event performance: 2013 Aggregate

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	126.3	102.5	95.7	(6.8)	93.3%	75.7%
AEP	1,660.0	830.2	1,312.1	481.9	158.1%	79.0%
ATSI	809.1	690.0	611.7	(78.2)	88.7%	75.6%
BGE	860.0	627.2	697.3	70.1	111.2%	81.1%
DLCO	113.2	69.2	48.9	(20.3)	70.7%	43.2%
Dominion	877.3	751.7	672.9	(78.8)	89.5%	76.7%
DPL	302.2	220.3	231.4	11.1	105.0%	76.6%
JCPL	210.2	156.7	140.6	(16.1)	89.7%	66.9%
Met-Ed	238.0	173.6	182.8	9.2	105.3%	76.8%
PECO	662.3	410.3	320.0	(90.4)	78.0%	48.3%
Penelec	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Pepco	495.2	371.9	252.2	(119.7)	67.8%	50.9%
PPL	777.0	621.5	583.6	(37.8)	93.9%	75.1%
PSEG	475.2	350.6	277.0	(73.6)	79.0%	58.3%
RECO	6.4	4.0	4.8	0.7	118.0%	73.9%
Total	7,954.3	5,644.7	5,670.2	25.6	100.5%	71.3%

Performance for specific customers varied significantly. Table 6-21 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 6-21 includes the participation for Subzonal and Zonal dispatch. For these events, approximately 28 percent of participants showed no reduction, load increased or participants did not report data. Approximately 54 percent of participants provided less than half of their committed MW. The majority of participants, approximately 81 percent, provided less than 100 percent reduction compared to their commitment. Figure 6-3 shows the data in Table 6-21.[9] The distribution includes high frequencies of both under performing and over performing registrations.

Table 6-21 Distribution of participant event days 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	Cumulative proportion
0%, load increase, or no reporting	5,013	28%	28%
0% - 10%	1,345	7%	35%
10% - 20%	1,069	6%	41%
20% - 30%	906	5%	46%
30% - 40%	814	5%	51%
40% - 50%	705	4%	54%
50% - 60%	681	4%	58%
60% - 70%	635	4%	62%
70% - 80%	671	4%	65%
80% - 90%	674	4%	69%
90% - 100%	2,076	11%	81%
100% - 110%	1,381	8%	88%
110% - 125%	645	4%	92%
125% - 150%	588	3%	95%
150% - 175%	283	2%	97%
175% - 200%	163	1%	98%
200% - 300%	278	2%	99%
> 300%	158	1%	100%
Total	18,085	100%	

9 Participant event days, shown in Figure 6-3, and Table 6-20, 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.

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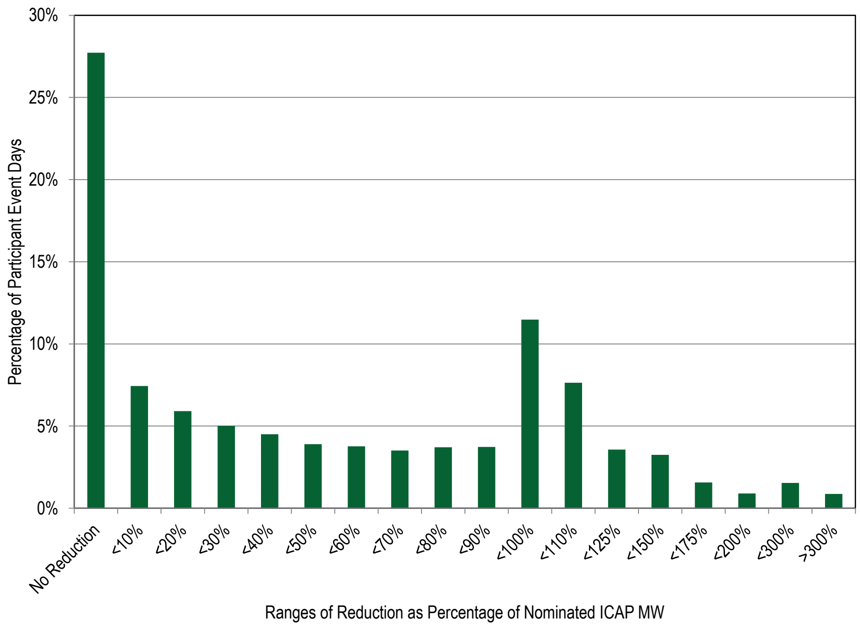
Figure 6-3 Distribution of participant event days across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period



Load Management Analysis

Currently, 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 netted within registrations, within hours. 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 would show a 75 MWh load reduction for that event hour. Settlement MWh are not netted across hours or across registrations for compliance purposes, but are set to zero if they are negative. 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 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 a negative reduction are treated as zero for compliance purposes. Overall, 20 percent of event hours reported showed negative reductions, or an increase in the load at the site.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 4.6 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 6-22 shows load management event performance, explicitly netting out negative load reduction values that were reported. These reported negative values were set to zero in PJM's reported compliance values, consistent with the rules. The Actual compliance numbers conservatively assume that non-reporting locations were zero. Compliance decreases from 100.5 percent to 90.7 percent when known negative compliance is included. Considering all and only reported values, the observed load reduction of the five events in 2013 was 5,028.0 MW, rather than the 5,670.2 MW reported. It is likely that

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these results still overstate compliance, as 10.3 percent of locations did not report for 2013 event compliance and these locations are assumed to have a zero reduction. Accounting for negative compliance and requiring all CSPs to submit all data for each location will result in more accurate measures of Demand Response performance.

Table 6-22 Load Management Event Performance with negative compliance: 2013

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	126.3	102.5	88.9	(13.6)	86.7%	70.4%
AEP	1,660.0	830.2	1,201.4	371.3	144.7%	72.4%
ATSI	809.5	690.0	474.8	(215.2)	68.8%	58.7%
BGE	860.0	627.2	676.7	49.5	107.9%	78.7%
DLCO	113.2	69.2	38.6	(30.6)	55.7%	34.1%
Dominion	877.3	751.7	612.4	(139.3)	81.5%	69.8%
DPL	302.2	220.3	217.1	(3.3)	98.5%	71.8%
JCPL	210.2	156.7	117.9	(38.8)	75.2%	56.1%
Met-Ed	238.0	173.6	170.1	(3.5)	98.0%	71.5%
PECO	662.3	410.3	249.0	(161.3)	60.7%	37.6%
Penelec	342.0	265.0	239.3	(25.8)	90.3%	70.0%
Pepco	495.2	371.9	241.1	(130.9)	64.8%	48.7%
PPL	777.0	621.5	546.7	(74.7)	88.0%	70.4%
PSEG	475.2	350.6	239.3	(111.3)	68.3%	50.4%
RECO	6.4	4.0	3.8	(0.3)	93.6%	58.6%
Total	7,828.4	5,542.2	5,028.0	(514.2)	90.7%	64.2%

Table 6-23 shows the difference between actual performance and reported performance, including the negative values that were measured during emergency events. This adjustment shows less than 100 percent compliance all zones but AEP and BGE. Actual compliance for the ATSI zone was 68.8 percent rather than 88.7 percent.

Table 6-23 Load Management Event Performance Comparison: Reported Reduction vs. Actual Reduction: 2013

Zone	Committed MW	Load Reduction Reported (MWh)	Actual Load Reduction (MWh)	Difference	Percent Compliance Reported	Percent Compliance Actual
AECO	102.5	95.7	88.9	6.8	93.3%	86.7%
AEP	830.2	1,312.1	1,201.4	110.7	158.1%	144.7%
ATSI	690.0	611.7	474.8	137.0	88.7%	68.8%
BGE	627.2	697.3	676.7	20.6	111.2%	107.9%
DLCO	69.2	48.9	38.6	10.3	70.7%	55.7%
Dominion	751.7	672.9	612.4	60.5	89.5%	81.5%
DPL	220.3	231.4	217.1	14.4	105.0%	98.5%
JCPL	156.7	140.6	117.9	22.7	89.7%	75.2%
Met-Ed	173.6	182.8	170.1	12.7	105.3%	98.0%
PECO	410.3	320.0	249.0	71.0	78.0%	60.7%
Penelec	265.0	239.3	239.3	0.0	90.3%	90.3%
Pepco	371.9	252.2	241.1	11.2	67.8%	64.8%
PPL	621.5	583.6	546.7	36.9	93.9%	88.0%
PSEG	350.6	277.0	239.3	37.7	79.0%	68.3%
RECO	4.0	4.8	3.8	1.0	118.0%	93.6%
Total	5,644.7	5,670.2	5,116.9	553.3	100.5%	90.6%

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Table 6-24 shows the number of locations attached to registrations that did not report during 203 event days. In total, 10.3 percent of locations did not report during event days in 2013 and were assigned zero load response MW in the actual PJM accounting 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 on 2013 Event Days

Event Date	Zone	Locations Not Reporting	Total Locations	Percent Non Reporting
15-Jul-13	ATSI	59	820	7.2%
16-Jul-13	ATSI	55	822	6.7%
18-Jul-13	ATSI	55	810	6.8%
	PECO	52	1,526	3.4%
	PPL	10	1,488	0.7%
	AEP Canton Subzone	24	76	31.6%
10-Sep-13	ATSI	129	816	15.8%
	AEP Canton Subzone	19	76	25.0%
11-Sep-13	AECO	35	278	12.6%
	AEP	76	1,432	5.3%
	ATSI	115	820	14.0%
	BGE	150	1,026	14.6%
	DLCO	40	285	14.0%
	Dominion	123	926	13.3%
	DPL	123	612	20.1%
	JCPL	121	494	24.5%
	Met-Ed	26	486	5.3%
	PECO	217	1,511	14.4%
	Penelec	14	626	2.2%
	Pepco	185	724	25.6%
	PPL	67	1,485	4.5%
	PSEG	196	1,173	16.7%
	RECO	0	19	0.0%
Total		1,891	18,331	10.3%

Table 6-25 shows the nominated capacity of non-reporting locations. Approximately 4.7 percent of nominated capacity, by MW, during event days did not report. It is likely that these locations had load above or equal to their commitment and took no action to reduce load during the PJM declared emergency.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. The MMU recommends that compliance rules be revised to require submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event.

Table 6-25 Non Reporting Locations by MW on 2013 Event Days

Event Date	Zone	Nominated ICAP Not Reporting	Nominated ICAP	Percent Non Reporting
15-Jul-13	ATSI	13.0	810.7	1.6%
16-Jul-13	ATSI	11.7	802.2	1.5%
18-Jul-13	ATSI	11.1	797.7	1.4%
	PECO	11.3	733.2	1.5%
	PPL	1.8	791.8	0.2%
	AEP Canton Subzone	14.5	129.4	11.2%
10-Sep-13	ATSI	43.1	808.8	5.3%
	AEP Canton Subzone	13.9	129.4	10.8%
11-Sep-13	AECO	8.3	126.3	6.6%
	AEP	12.8	1,660.0	0.8%
	ATSI	32.0	826.0	3.9%
	BGE	59.5	860.0	6.9%
	DLCO	8.7	113.2	7.7%
	Dominion	33.9	877.3	3.9%
	DPL	39.2	302.2	13.0%
	JCPL	31.4	210.2	15.0%
	Met-Ed	4.6	238.0	1.9%
	PECO	69.2	591.4	11.7%
	Penelec	3.0	342.0	0.9%
	Pepco	59.0	495.2	11.9%
	PPL	67.4	762.2	8.8%
	PSEG	60.8	475.2	12.8%
	RECO	0.0	6.4	0.0%
Total		610.3	12,888.8	4.7%

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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 deployed and that demonstrated a load reduction were eligible to receive emergency energy payments, which are equal to the higher of hourly zonal LMP or an 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/MWh. The maximum offer increases to $2,100/MWh for the 2014/2015 and $2,700/MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000/MWh.[10]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-26 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, 69.7 percent, have a minimum dispatch price of $1,000/MWh, and 18.4 percent of participants have a dispatch price of $1,800/MWh, which is the maximum 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 - $999 strike prices had the highest average at $1,881.32 per registration.

Until this year, shutdown costs have not been adequately defined in Manual 15. PJM's Cost Development Subcommittee recently approved changes in Manual 15 to eliminate shutdown costs for Demand Response Resources. Going forward, and according to the changes in Manual 15, "Demand Side Response shutdown costs shall be zero."[11]

Table 6-26 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2013/2014 Delivery Year[12]

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Registration
$0-$1	538	3.6%	971.2	9.2%	$0.00
$1-$200	905	6.0%	536.1	5.1%	$8.73
$200-$500	216	1.4%	190.8	1.8%	$141.90
$500-$999	133	0.9%	138.9	1.3%	$1,881.32
$1,000	10,499	69.7%	6,891.9	65.2%	$0.04
$1,000-$1,799	0	0.0%	0.0	0.0%	$0.00
$1,800	2,776	18.4%	1,833.7	17.4%	$0.00
Total	15,067	100%	10,562.6	100%	$37.32

Table 6-27 shows emergency credits and make whole payments for each event in 2013 by zone. The emergency credit is the market value of the load reductions observed during the event, based on applicable zonal LMPs. Make whole payments are the difference between the market value of the load reduction and the submitted energy offer, which includes the strike price and shutdown cost of each resource. The LMP in ATSI was $1,705.04/MWh on average during the July 18, 2013 event, resulting in a total make whole payment in the ATSI zone of $181,551.93, compared to an average of $96.48/MWh during the July 16, 2013 event, which resulted in $1,669,845.10 in make whole payments, a difference of $1,488,293.17.[13]

Table 6-27 Emergency credits and make whole payments by event by zone: 2013

Event	Zone	Emergency Credits	Emergency Make Whole Payments	Total
15-Jul-13	ATSI	$307,182.68	$1,292,511.93	$1,599,694.61
16-Jul-13	ATSI	$157,662.19	$1,669,845.10	$1,827,507.29
18-Jul-13	AEP	$73,745.90	$623,180.50	$696,926.40
	ATSI	$552,809.78	$181,551.93	$734,361.71
	PECO	$157,718.40	$1,216,408.67	$1,374,127.07
	PPL	$246,492.69	$1,938,974.34	$2,185,467.03
Total		$1,495,611.64	$6,922,472.47	$8,418,084.11

10 139 FERC ¶ 61,057 (2012).
11 PJM: "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p 51.

12 In this analysis Nominated MW does not include capacity only resources, which do not receive energy market revenue.
13 September Event data for Emergency Credits will not be available at publication date.

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Energy payments in the Emergency Program differ significantly from energy payments in the Economic Program and from capacity payments through the Load Management 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.

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 12:00pm to 8:00pm EPT and be capable of maintaining an interruption for 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, 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 the AEP Canton Subzone dispatch was not penalized for underperformance. The penalties are assessed daily and have increased by $547,122.42 from $681,094.28 in June through September of the 2012/2013 Delivery Year compared to $1,228,216.70 of the same period in the 2013/2014 Delivery Year. Table 6-28 shows penalty charges by zone for June through September of the 2012/2013 and 2013/2014 Delivery Year. PECO had the highest penalty amount, due to the clearing prices in EMAAC and performance at 82.6 percent of the committed MW.[14] The penalties for the September 10 and September 11 events have not been assessed yet due to data lag.

Table 6-28 Penalty Charges per Zone: June through September 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$30.50	$0.00
AEP	$47,964.30	$0.00
AP	$0.00	$0.00
ATSI	$0.00	$132,023.52
BGE	$44,738.62	$0.00
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$19,727.40	$0.00
DPL	$247,595.34	$0.00
DLCO	$0.00	$0.00
EKPC	$0.00	$0.00
JCPL	$1,782.42	$0.00
Met-Ed	$0.00	$0.00
PECO	$133,499.72	$769,238.67
PENELEC	$14,729.06	$0.00
Pepco	$167,425.48	$0.00
PPL	$198.86	$326,954.51
PSEG	$3,402.58	$0.00
RECO	$0.00	$0.00
Total	$681,094.28	$1,228,216.70

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

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