Ohio | Public Utilities Commission

LARGE FILING SEPARATOR SHEET

CASE NUMBER: 14-1297-EL-SSO

FILE DATE: 10/20/15

SECTION: 2 OF 5

FILED BY:ARMSTRONG & OKEY

FILED ON BEHALF OF: PUCO

NUMBER OF PAGES: 211

DESCRIPTION OF DOCUMENT:

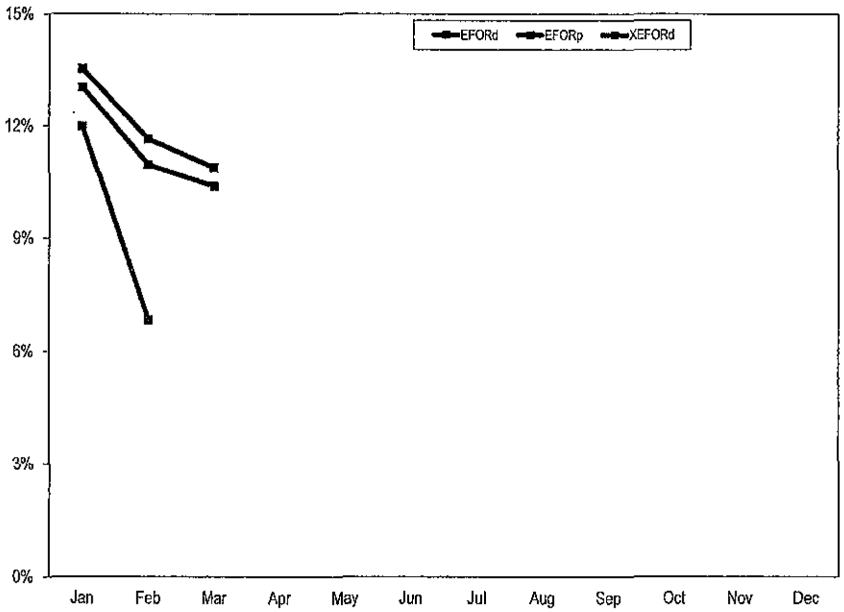
EXHIBITS: VOLUME XXIV

COMPANIES 74, 75, 76, 77, 78, 79, 80, 81

180 East Broad Street
Columbus, Ohio 43215-3793

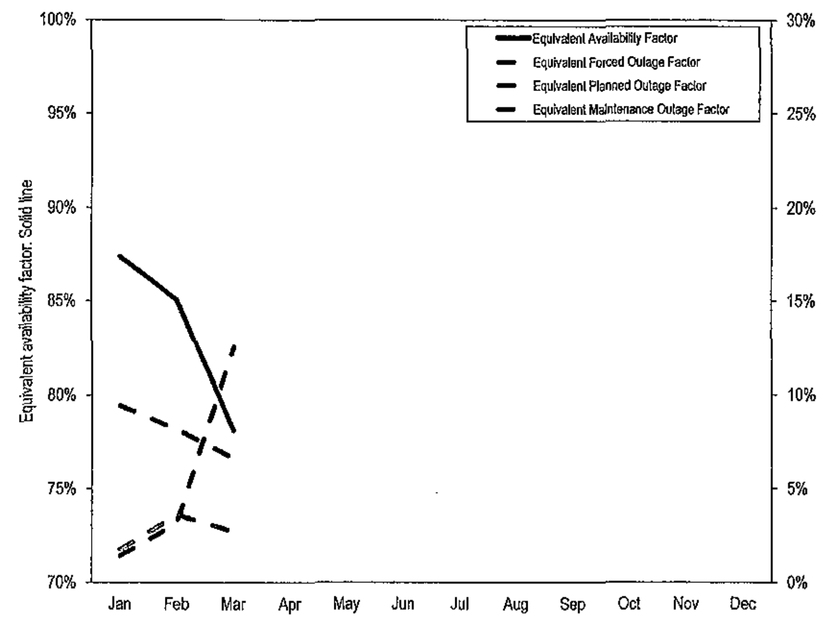
(614) 466-3016
www.PUCO.ohio.gov

Figure 5-10 PJM EFORd, XEFORd and EFORp: January through March 2014



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-11.

Figure 5-11 PJM monthly generator performance factors: January through March 2014



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 increased by $10.5 million, from $1.0 million in the first three months of 2013 to $11.6 million in the first three months of 2014, a 970 percent increase. Emergency energy credits increased by $37.1 million to $37.1 million compared to the first three months of 2013. The capacity market is the primary source of revenue to participants in PJM demand response programs. In the first three months of 2014, capacity market revenues increased by $71.8 million, or 108.8 percent, from $66.0 million in the first three months of 2013 to $137.8 million in the first three months of 2014.[1]

  All demand response energy payments are uplift. LMP does not cover demand response energy payments. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Emergency demand response energy costs are not covered by LMP. 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.2

- **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.

- **Emergency Event Day Analysis.** Emergency energy revenue increased by $37.1 million, from $0.0 million in the first three months of 2013 to $37.1 in the first three months of 2014. 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 average load reduction of the seven events in the first three months of 2014 should have been 1,594.6 MW, rather than the 2,079.5 MW calculated using PJM's method. The correct calculation of compliance is 26.9 percent rather than PJM's calculated 35.1 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.

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

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.

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.

Table 6-1 Overview of demand response programs

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 the first three months of 2014, credits and MWh in the economic program were higher than in the same period for each of the last five years. There were more settlements submitted and more active participants in the first three months of 2014 compared to the first three months of 2013, and credits increased.

Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through the first three months of 2014. Since the implementation of the RPM capacity market on June 1, 2007, the capacity market has been the primary source of revenue to demand response participants, accounting for 92.4 percent of all revenue received through demand response programs in the first three months of 2014. In the first three months of 2014, total credits under the economic program increased by $10,509,971, from $1,083,755 in the first three months of 2013 to $11,593,726 in the first three months of 2014. This represents a 970 percent increase in credits. In the first three months of 2014, capacity revenue accounted for 72.8 percent of all revenue received by demand response providers, emergency energy revenue was 19.6 percent, revenue from the economic program was 6.1 percent and revenue from synchronized reserve was 1.5 percent.

Capacity revenue increased by $71.8 million, or 108.8 percent, from $66.0 million in the first three months of 2013 to $137.8 million in the first three months of 2014, primarily due to higher clearing prices in the capacity market for the 2013/2014 Delivery Year. The emergency energy revenue increased by $37.1 million to $37.1 million in the first three months of 2014.

Figure 6-1 Demand response revenue by market: 2002 through March, 2014

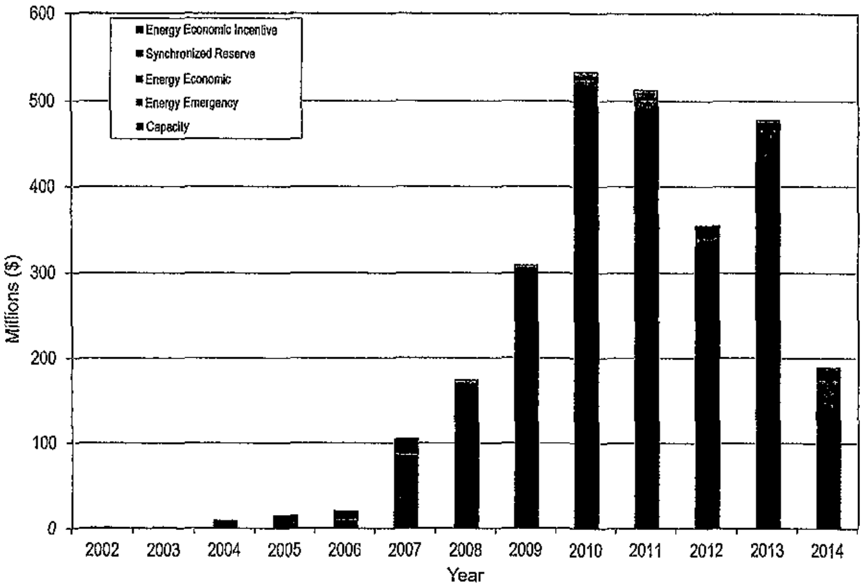


Table 6-2 Economic program registrations on the last day of the month: 2011 through March, 2014

	2011		2012		2013		2014	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,607	2,429	1,993	2,385	841	2,336	1,180	2,357
Feb	1,612	2,435	1,995	2,384	843	2,350	1,174	2,363
Mar	1,610	2,518	1,996	2,356	788	2,307	1,185	2,679
Apr	1,611	2,534	189	1,321	970	2,369		
May	1,600	2,483	371	1,709	1,375	2,437		
Jun	1,136	1,849	803	2,435	1,302	2,166		
Jul	1,228	2,062	942	2,416	1,315	2,501		
Aug	1,982	2,194	1,013	2,469	1,299	2,597		
Sep	1,960	2,181	1,052	2,516	1,280	2,545		
Oct	1,954	2,179	828	2,364	1,210	2,405		
Nov	1,986	2,220	824	2,362	1,192	2,377		
Dec	1,992	2,259	846	2,379	1,192	2,382		
Avg.	1,690	2,279	1,071	2,258	1,134	2,398	1,180	2,466

Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period 2010 through the first three months of 2014. The average number of registrations and registered MW increased in the first three months of 2014. The average monthly registered MW for the first three months of 2014 increased by 135 MW from 2,331 MW in the first three months of 2013 to 2,466 MW in the first three months of 2014. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations increased by 356 from 824 in the first three months of 2013 to 1,180 in the first three months of 2014. The economic program's registered MW have not increased significantly with FERC Order No. 745. The average registered MW in the first three months of 2011, before FERC Order No. 745, was 2,461 MW, and the average registered MW in the first three months of 2014 was 2,466 MW, an increase of 5 MW.

There is a large overlap between economic registrations and emergency capacity registrations. *There were 499 registrations and 2,406 MW of* nominated MW in the emergency program, that were in both the economic and emergency programs. The registered MW in the economic load response program are not a good measure of the amount of MW available for dispatch. Economic resources can dispatch more, less or the amount of MW registered in the program.

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 sum of maximum economic MW dispatched by registration each month for 2010 through the first three months of 2014. The maximum dispatched MW for each registration for each month were added together 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 registration dispatched in the first three months of 2014 increased by 259 MW, from 233 MW in the first three months of 2013 to 493 MW in the first three months of 2014. The increase of dispatched MW by registration was a result of high LMP in the first three months of 2014. January and February of 2014 had more dispatched MW than January and February in each of the last four years. July of 2012 had the highest recorded MW dispatched for the last four years at 1,641 maximum MW dispatched by registration.

Table 6-3 Maximum economic MW dispatched by registration per month: 2011 through March, 2014

	Maximum Dispatched MW by Registration			
Month	2011	2012	2013	2014
Jan	243	104	193	426
Feb	190	101	119	306
Mar	153	72	127	271
Apr	80	108	133	
May	98	143	192	
Jun	561	944	431	
Jul	561	1,641	1,088	
Aug	161	980	497	
Sep	84	451	517	
Oct	81	242	157	
Nov	86	165	154	
Dec	88	99	161	
Total	841	1,956	1,472	493

Economic demand response energy costs are assigned to PJM market participants as uplift 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.[6] 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 $169.45 per MWh, from $51.49 per MWh in the first three months of 2013 to $220.94 per MWh dispatched in the first three months of 2014. The average LMP for the RTO increased by $49.77 per MWh, from $37.49 per MWh during the first three months of 2013 to $87.26 per MWh during the first three months of 2014. The increase in Table 6-4 is a result of high LMPs in the first quarter of 2014. Curtailed energy for the economic program was 52,475 MWh in the first three months of 2014 and the total payments were $11,593,726. Credits, for the first three months of 2014, increased by $10,509,971, or 970 percent, compared to the first three months of 2013. Economic demand response resources that are dispatched in both the economic and emergency programs are settled under emergency rules. For example, assume a demand resource has an economic strike price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource was scheduled to reduce in the Day-Ahead Energy Market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead of the economic strike price of $100 per MWh.

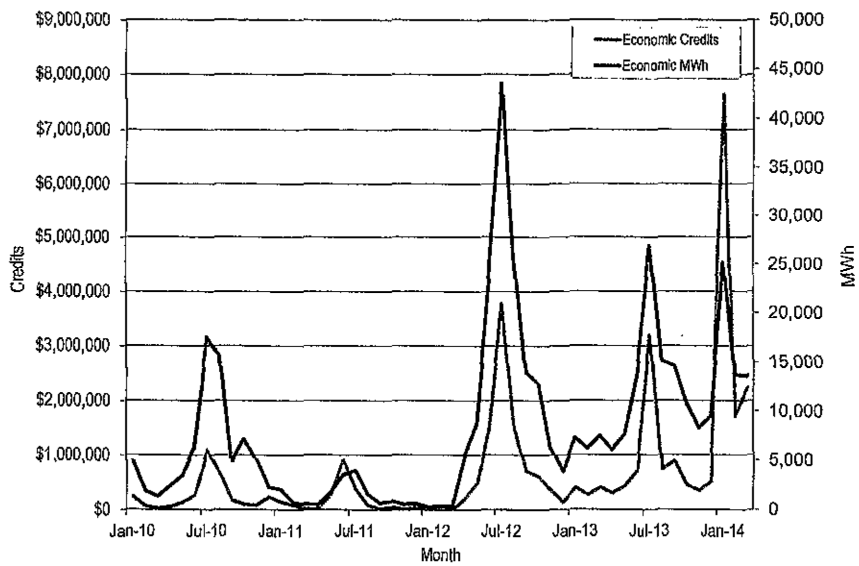
Table 6-4 Credits paid to the PJM economic program participants excluding incentive credits: January through March, 2010 through 2014

Year (Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	52,475	$11,593,726	$220.94

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

Figure 6-2 shows monthly economic demand response credits and MWh, for 2010 through the first three months of 2014. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The high LMPs in the first quarter of 2014 driven by an extremely cold winter in PJM resulted in more participation in the economic program. The January economic credits were more than twice the previous monthly maximum in July 2012 and the highest in the last five years.

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



Total economic program reductions increased 149 percent from 21,048 MW in the first three months of 2013 to 52,475 MW in the first three months of 2014. The economic credits increased by 970 percent from $1,083,755 in the first three months of 2013, to $11,593,726 in the first three months of 2014. (Table 6-5)

Table 6-5 PJM Economic program participation by zone: January through March, 2013 and 2014[7]

	Credits			MWh Reductions		
Zones	2013	2014	Percentage Change	2013	2014	Percentage Change
Total	$1,083,755	$11,593,726	970%	21,048	52,475	149%

Table 6-6 shows total settlements submitted by year for 2008 through the first three months of 2014. 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 1,724 economic settlements in the first three months of 2014, which increased by 1,314 from the 410 settlements in the first three months of 2013.

Table 6-6 Settlements submitted by year in the economic program: 2008 through March, 2014

	2008	2009	2010	2011	2012	2013	2014 (Jan-Mar)
Total	32,990	21,605	12,697	4,591	7,894	3,904	1,724

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 the first three months of 2014. The number of active participants during the first three months of 2014 increased by 74 to 127, compared to the first three months of 2013, when 53 participants from 10 CSPs were active.

7 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).

Table 6-7 Distinct participants and CSPs submitting settlements in the Economic Program by year: 2009 through March, 2014

	2009		2010		2011		2012		2013		2014-Q1	
Month	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	25	747	24	438	20	610	24	520	22	291	13	127

Table 6-8 shows average MWh reductions and credits by hour for the first three months of 2013 and the first three months of 2014. The majority of reductions occurred between hours ending 0800 and hour ending 1900 in the first three months of 2014. The credits earned increased for each hour in the first three months of 2014 compared to the first three months of 2013. Reductions occurred over all hours when LMP was above the net benefit test threshold in the first three months of 2014. The MWh reductions increased by 149 percent compared to 2013, and credits increased by 970 percent.

Table 6-8 Hourly frequency distribution of economic program MWh reductions and credits: January through March, 2013 and 2014

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2013	2014	Percentage Change	2013	2014	Percentage Change
1 through 7	3,104	9,487	206%	$168,168	$1,827,157	987%
8	3,373	3,987	18%	$221,471	$934,116	322%
9	3,204	4,018	25%	$164,528	$699,368	325%
10	2,911	4,190	44%	$132,995	$815,804	513%
11	2,315	3,072	33%	$108,284	$714,435	560%
12	1,923	2,323	21%	$83,366	$628,938	654%
13	1,363	2,261	66%	$58,242	$465,190	699%
14	502	2,119	322%	$20,453	$432,496	2,015%
15	264	1,855	604%	$9,375	$363,680	3,779%
16	265	1,788	575%	$9,544	$314,293	3,193%
17	314	1,833	485%	$11,968	$337,111	2,717%
18	325	2,394	637%	$16,190	$621,482	3,739%
19	474	2,592	447%	$28,311	$731,596	2,484%
20 through 24	711	10,556	1,384%	$50,861	$2,708,061	5,224%
Total	21,048	52,475	149%	$1,083,755	$11,593,726	970%

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 $31.63 per MWh for the first three months of 2014, a $5.76 per MWh increase from $25.87 per MWh in the first three months of 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 in the first three months of 2013 and 2014. Reductions occurred at all price levels. Approximately 30 percent of MWh reductions and 58 percent of program credits are associated with hours when the applicable zonal LMP was higher than $250 per MWh. MWh reductions in the first three months of 2014 increased 149 percent compared to the first three months of 2013.

Table 6-9 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through March, 2013 and 2014

	MWh Reductions			Program Credits		
LMP	2013	2014	Percentage Change	2013	2014	Percentage Change
$0 to $50	14,479	5,721	(60%)	$596,493	$359,302	(40%)
$50 to $75	3,236	8,580	165%	$194,052	$600,429	209%
$75 to $100	947	5,829	515%	$67,853	$627,737	825%
$100 to $125	993	3,324	235%	$72,677	$456,842	529%
$125 to $150	296	3,234	994%	$28,636	$519,174	1,713%
$150 to $200	460	5,751	1,151%	$60,489	$1,213,833	1,907%
$200 to $250	450	4,569	915%	$46,424	$1,095,991	2,261%
> $250	187	15,466	8,166%	$17,131	$6,720,418	39,131%
Total	21,048	52,475	149%	$1,083,755	$11,593,726	970%

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 that 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.[8]

Table 6-10 shows zonal monthly capacity credits to demand resources for the first three months of 2014. Capacity revenue increased in the first three months of 2014 by $71.8 million, or 108.8 percent, compared to the first three months of 2013, from $66.0 million to $137.8 million as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 Delivery Year.[9]

Table 6-10 Zonal monthly capacity credits: January through March, 2014

Zone	January	February	March	Total
AECO	$1,035,717	$935,486	$1,035,717	$3,006,921
AEP, EKPC	$776,197	$701,081	$776,197	$2,253,474
AP	$493,260	$445,525	$493,260	$1,432,044
ATSI	$377,750	$341,193	$377,750	$1,096,692
BGE	$7,736,807	$6,988,083	$7,736,807	$22,461,697
ComEd	$808,185	$729,973	$808,185	$2,346,343
DAY	$44,278	$39,993	$44,278	$128,548
DEOK	$16,653	$15,041	$16,653	$48,346
DLCO	$605,391	$546,805	$605,391	$1,757,587
Dominion	$1,979,013	$1,787,496	$1,979,013	$5,745,522
DPL	$148,045	$133,718	$148,045	$429,808
JCPL	$2,288,883	$2,067,378	$2,288,883	$6,645,143
Met-Ed	$2,246,581	$2,029,170	$2,246,581	$6,522,333
PECO	$5,314,219	$4,799,939	$5,314,219	$15,428,377
PENELEC	$2,980,723	$2,692,266	$2,980,723	$8,653,713
Pepco	$4,229,396	$3,820,100	$4,229,396	$12,278,892
PPL	$7,253,736	$6,551,762	$7,253,736	$21,059,234
PSEG	$8,859,978	$8,002,561	$8,859,978	$25,722,517
RECO	$257,721	$232,781	$257,721	$748,223
Total	$47,452,531	$42,860,351	$47,452,531	$137,765,414

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 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
Total	609.8	990.9	62%	631.2	1,029.2	63%

8 See "Complaint and Motion to Consolidate of the Independent Market Monitor," Docket No. EL14-20-000 (January 28, 2014).
9 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 6-12 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	1,767.1	2,092.7	279.6	842.4	3,267.2	78.6	235.8	8,563.6	88.1%
Guaranteed Load Drop	60.6	216.1	0.9	84.4	27.5	0.8	12.5	402.8	4.1%
Non hourly metered sites (DLC)	0.0	712.4	0.0	0.0	0.0	40.0	0.0	752.4	7.7%
Total	1,827.8	3,021.2	280.5	926.8	3,294.7	119.4	248.3	9,718.7	100.0%
Percentage by method	18.8%	31.1%	2.9%	9.5%	33.9%	1.2%	2.6%	100.0%	

Table 6-12 shows the MW registered by measurement and verification method and by load drop method. Of the DR MW committed, 4.1 percent use the guaranteed load drop (GLD) measurement and verification method, 88.1 percent use firm service level (FSL) method and 7.7 percent use direct load control (DLC).

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

Table 6-13 shows the fuel type used in the on-site generators identified in Table 6-12. Of the 18.8 percent of emergency demand response identified as using on-site generation, 79.1 percent of MW are diesel, 5.2 percent are natural gas and 15.7 percent is coal, oil, other or no fuel source.[10]

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

Fuel Type	MW	Percentage
Coal, Oil, Other	16.3	0.9%
Diesel	1,446.0	79.1%
Natural Gas	94.2	5.2%
None	271.2	14.8%
Total	1,827.8	100.00%

Emergency Event Reported Compliance

PJM declared eight emergency events in the first three months of 2014, two on January 7, one on January 8, one on January 22, two on January 23, one on January 24 and one on March 4. There were 13 events during the 2013/2014 Delivery Year through March 2014, two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of the 2014 events occurred outside of the summer compliance period, none were considered in PJM's compliance assessment. 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%

10 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.

Table 6-15 lists PJM emergency load management events declared by PJM in the first three months of 2014 and the affected zones. The SWMAAC region was called for all eight events. All demand response events called in the first three months of 2014 were voluntary, so no penalties are assessed for under compliance.

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.

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

Table 6-15 PJM declared load management events: January through March, 2014

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

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

Subzonal dispatch by zip code is currently voluntary, but will be mandatory beginning with the 2014/2015 delivery year.[11] 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.

11 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.[12] 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 first January 7, 2014, 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.

The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The RECO Control Zone was the only zone to achieve over 100 percent compliance at 119.7 percent reported compliance, or 114.0 percent observed compliance. Overall, the reported compliance for the first event on January 7, 2014, was 37.4 percent, or 2,815.3 MW out of 7,535.7 MW committed. The observed compliance level was 28.4 percent compliance or 2,143.2 MW, a difference of 672.1 MW compared to the reported load reduction.

Table 6-16 Demand response event performance: January 7, 2014 (Event 1)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	41.5	102.5	23.8	19.4	4.4	23.3%	18.9%
AEP	1,211.4	1,253.6	756.2	650.0	106.1	60.3%	51.9%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	674.6	683.1	452.9	349.3	103.6	66.3%	51.1%
BGE	243.4	627.2	205.7	181.8	23.9	32.8%	29.0%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	38.5	69.2	22.7	(2.0)	24.8	32.9%	(3.0%)
Dominion	656.1	757.0	440.6	370.2	70.4	58.2%	48.9%
DPL	103.4	65.9	58.2	41.8	16.4	88.2%	63.4%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	97.5	156.7	77.4	59.9	17.6	49.4%	38.2%
Met-Ed	169.9	173.9	80.6	57.0	23.5	46.3%	32.8%
PECO	309.6	410.3	182.3	131.8	50.6	44.4%	32.1%
PENELEC	203.1	265.1	66.1	0.3	65.9	24.9%	0.1%
Pepco	102.0	372.0	97.6	72.7	24.9	26.2%	19.5%
PPL	505.1	621.1	241.0	137.7	103.3	38.8%	22.2%
PSEG	194.5	350.6	105.2	68.7	36.5	30.0%	19.6%
RECO	3.8	4.0	4.8	4.6	0.2	119.7%	114.0%
Total	4,554.4	7,535.7	2,815.3	2,143.2	672.1	37.4%	28.4%

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

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

Table 6-17 shows the performance for the second January 7, 2014, event. *The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for* this event. The DPL Control Zone performed at an 86.8 percent reported compliance, or 57.3 MW out of 65.9 MW committed. The DPL Control Zone performed at a 67.6 percent observed compliance, or 44.5 MW out of 65.9 MW committed. Overall, the reported compliance for the second event on January 7, 2014, was 39.6 percent, or 2,984.4 MW out of 7,535.7 MW committed. The observed compliance level was 31.9 percent compliance or 2,405.2 MW, a difference of 579.1 MW.

Table 6-17 Demand response event performance: January 7, 2014 (Event 2)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	41.5	102.5	22.7	20.1	2.6	22.1%	19.6%
AEP	1,211.4	1,253.6	806.9	681.1	125.8	64.4%	54.3%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	674.6	683.1	534.9	452.3	82.6	78.3%	66.2%
BGE	243.4	627.2	219.3	200.7	18.7	35.0%	32.0%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	38.5	69.2	22.2	(23.5)	45.7	32.1%	(34.0%)
Dominion	656.1	757.0	439.2	390.8	48.3	58.0%	51.6%
DPL	103.4	65.9	57.3	44.5	12.7	86.8%	67.6%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	97.5	156.7	74.3	55.9	18.4	47.4%	35.7%
Met-Ed	169.9	173.9	84.8	71.3	13.6	48.8%	41.0%
PECO	309.6	410.3	172.9	133.3	39.6	42.1%	32.5%
PENELEC	203.1	265.1	96.9	62.0	34.9	36.6%	23.4%
Pepco	102.0	372.0	102.2	84.0	18.2	27.5%	22.6%
PPL	505.1	621.1	244.2	167.1	77.2	39.3%	26.9%
PSEG	194.5	350.6	104.4	63.5	40.9	29.8%	18.1%
RECO	3.8	4.0	2.2	2.2	0.1	55.7%	54.0%
Total	4,554.4	7,535.7	2,984.4	2,405.2	579.1	39.6%	31.9%

There was one event on January 8, 2014. The event was called for both long and short lead resources for the RTO at 500 and ended the event at 700 EPT. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. Short lead resources were active for one *hour and long lead resources were not active during this call. Table 6-18* shows the performance for the January 8, 2014, event.. The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The DPL Control Zone performed at 60.9 percent reported compliance, or 40.2 MW out of 65.9 MW committed. The DPL Control Zone performed at a 54.5 percent observed compliance, or 36.0 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 8, 2014, was 28.2 percent, or 2,123.6 MW out of 7,537.7 MW committed. The observed compliance level was 20.4 percent compliance or 1,535.7 MW, a difference of 587.9 MW.

Table 6-18 Demand response event performance: January 8, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	27.2	102.5	17.1	15.2	1.9	16.7%	14.8%
AEP	1,116.2	1,253.6	699.7	582.1	117.6	55.8%	46.4%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	588.1	683.1	364.6	274.0	90.7	53.4%	40.1%
BGE	162.2	627.2	120.8	100.6	20.2	19.3%	16.0%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	22.4	69.2	16.4	8.5	7.9	23.7%	12.3%
Dominion	537.0	757.0	288.9	208.6	80.2	38.2%	27.6%
DPL	70.3	65.9	40.2	36.0	4.2	60.9%	54.5%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	65.0	156.7	55.3	40.8	14.5	35.3%	26.0%
Met-Ed	147.2	173.9	54.1	14.1	40.0	31.1%	8.1%
PECO	212.2	410.3	115.6	78.3	37.3	28.2%	19.1%
PENELEC	137.1	265.1	46.5	(4.9)	51.4	17.5%	(1.8%)
Pepco	60.7	372.0	57.3	38.3	19.0	15.4%	10.3%
PPL	411.9	621.1	162.7	88.8	73.9	26.2%	14.3%
PSEG	145.9	350.6	83.6	54.4	29.2	23.8%	15.5%
RECO	1.0	4.0	0.8	0.8	0.0	21.0%	21.0%
Total	3,704.2	7,535.7	2,123.6	1,535.7	587.9	28.2%	20.4%

There was one event on January 22, 2014. The event was called for both long and short lead resources for the SWMAAC LDA at 1400 and ended the event at 2100 EPT. Table 6-19 shows the performance for the January 22, 2014, event.

The BGE Control Zone performed at 35.6 percent reported compliance, or 223.0 MW out of 627.2 MW committed. The BGE Control Zone performed at a 32.2 percent observed compliance, or 202.1 MW out of 627.2 MW committed. Overall, the reported compliance for the event on January 22, 2014, was 35.5 percent, or 355.0 MW out of 999.2 MW committed. The observed compliance level was 31.8 percent compliance or 317.3 MW, a difference of 37.7 MW.

Table 6-19 Demand response event performance: January 22, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
BGE	248.0	627.2	223.0	202.1	20.9	35.6%	32.2%
Pepco	98.5	372.0	132.0	115.2	16.8	35.5%	31.0%
Total	346.5	999.2	355.0	317.3	37.7	35.5%	31.8%

There were two events on January 23, 2014. The first event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 830 EPT. Table 6-20 shows the performance for the first January 23, 2014, event. The APS Control Zone did not submit any data for this event. The RECO Control Zone performed at 154.2 percent reported compliance, or 6.2 MW out of 4.0 MW committed. The RECO Control Zone performed at a 149.2 percent observed compliance, or 6.0 MW out of 4.0 MW committed. Overall, the reported compliance for the first event on January 23, 2014, was 37.1 percent, or 1,634.9 MW out of 4,412.2 MW committed. The observed compliance level was 27.2 percent compliance or 1,199.7 MW, a difference of 435.2 MW.

The second event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 1400 and ended the event at 1900 EPT. Table 6-21 shows the performance for the second January 23, 2014, event. The APS Control Zone did not submit any data for this event. The RECO Control Zone performed at 69.6 percent reported compliance, or 2.8 MW out of 4.0 MW committed. The RECO Control Zone performed at a 67.6 percent observed compliance, or 2.7 MW out of 4.0 MW committed. Overall, the reported compliance for the second event on January 23, 2014, was 36.0 percent, or 1,586.5 MW out of 4,412.2 MW committed. The observed compliance level was 29.2 percent compliance or 1,289.4 MW, a difference of 297.0 MW.

Table 6-20 Demand response event performance: January 23, 2014 (Event 1)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	32.0	102.5	19.4	17.6	1.8	18.9%	17.2%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	250.3	627.2	214.0	180.5	33.5	34.1%	28.8%
Dominion	605.4	757.0	442.6	384.1	58.5	58.5%	50.7%
DPL	81.0	65.9	41.7	30.4	11.3	63.2%	46.0%
JCPL	101.3	156.7	78.6	53.8	24.8	50.2%	34.4%
Met-Ed	170.6	173.9	90.1	66.2	23.9	51.8%	38.0%
PECO	304.2	410.3	184.9	133.2	51.7	45.1%	32.5%
PENELEC	174.5	265.1	49.2	(7.2)	56.4	18.5%	(2.7%)
Pepco	103.4	372.0	126.0	102.7	23.3	33.9%	27.6%
PPL	528.4	621.1	260.3	144.2	116.1	41.9%	23.2%
PSEG	208.2	350.6	121.9	88.1	33.7	34.8%	25.1%
RECO	5.0	4.0	6.2	6.0	0.2	154.2%	149.2%
Total	2,564.1	4,405.6	1,634.9	1,199.7	435.2	37.1%	27.2%

Table 6-21 Demand response event performance: January 23, 2014 (Event 2)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	32.0	102.5	18.8	17.2	1.5	18.3%	16.8%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	250.3	627.2	212.3	186.9	25.4	33.8%	29.8%
Dominion	605.4	757.0	472.6	433.8	38.8	62.4%	57.3%
DPL	0.0	65.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	81.0	156.7	41.1	31.4	9.7	26.2%	20.1%
Met-Ed	170.6	173.9	98.0	84.7	13.3	56.4%	48.7%
PECO	304.2	410.3	184.8	141.1	43.7	45.0%	34.4%
PENELEC	174.5	265.1	60.7	25.2	35.5	22.9%	9.5%
Pepco	103.4	372.0	125.4	109.5	15.9	33.7%	29.4%
PPL	528.4	621.1	259.9	177.5	82.3	41.8%	28.6%
PSEG	208.2	350.6	110.0	79.2	30.7	31.4%	22.6%
RECO	5.0	4.0	2.8	2.7	0.1	69.6%	67.6%
Total	2,462.9	4,405.6	1,586.5	1,289.4	297.0	36.0%	29.3%

There was one event on January 24, 2014. The event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 845 EPT. Table 6-22 shows the performance for the January 24, 2014, event. The APS Control Zone did not submit any data for this event. The DPL Control Zone performed at 54.4 percent reported compliance, or 35.9 MW out of 65.9 MW committed. The DPL Control Zone performed at a 45.0 percent observed compliance, or 29.7 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 24, 2014, was 29.8 percent, or 1,313.8 MW out of 4,405.6 MW committed. The observed compliance level was 21.8 percent compliance or 958.9 MW, a difference of 354.9 MW.

Table 6-22 Demand response event performance: January 24, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	27.6	102.5	17.4	15.7	1.7	17.0%	15.4%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	181.1	627.2	142.4	119.8	22.6	22.7%	19.1%
Dominion	523.1	757.0	370.6	310.2	60.4	49.0%	41.0%
DPL	71.6	65.9	35.9	29.7	6.2	54.4%	45.0%
JCPL	72.4	156.7	60.7	37.7	22.9	38.7%	24.1%
Met-Ed	154.1	173.9	82.9	60.7	22.3	47.7%	34.9%
PECO	236.2	410.3	149.2	106.0	43.3	36.4%	25.8%
PENELEC	162.2	265.1	49.2	7.9	41.3	18.6%	3.0%
Pepco	84.3	372.0	96.6	76.2	20.4	26.0%	20.5%
PPL	450.3	621.1	204.8	122.5	82.3	33.0%	19.7%
PSEG	177.5	350.6	103.0	71.8	31.2	29.4%	20.5%
RECO	2.0	4.0	1.0	0.8	0.2	25.7%	21.0%
Total	2,142.3	4,405.6	1,313.8	958.9	354.9	29.8%	21.8%

Table 6-23 shows load management event performance for the first seven demand response emergency events for 2014.[13] RTO wide percent reported compliance was 35.1 percent in the first three months of 2014 for resources called during emergency events, while observed compliance was 26.9 percent. The reported performance values treated locations showing increases in load, negative performance, as zero performance. The RECO Control Zone reported

13 The data for the March 4, 2014 will not be finalized until after publication.

74.3 percent compliance and observed 71.1 percent compliance were the highest in PJM, while the APS, ComEd, Day, DEOK and EKPC observed 0.0 percent compliance were the lowest.

The BGE and Pepco zones had all seven emergency calls and performed at an average of 26.7 and 23.0 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 6-23 Load management event performance: January through March, 2014 Aggregated

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	33.7	102.5	19.9	17.5	2.3	19.4%	17.1%
AEP	1,179.6	1,253.6	754.3	637.7	116.5	60.2%	50.9%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	645.8	683.1	450.8	358.5	92.3	66.0%	52.5%
BGE	225.5	627.2	191.1	167.5	23.6	30.5%	26.7%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	33.1	69.2	20.4	(5.7)	26.1	29.5%	(8.2%)
Dominion	597.2	757.0	409.1	349.6	59.5	54.0%	46.2%
DPL	71.6	65.9	38.9	30.4	8.5	58.9%	46.1%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	85.8	156.7	64.6	46.6	18.0	41.2%	29.7%
Met-Ed	163.7	173.9	81.8	59.0	22.8	47.0%	33.9%
PECO	279.3	410.3	165.0	120.6	44.4	40.2%	29.4%
PENELEC	175.8	265.1	61.5	13.9	47.6	23.2%	5.2%
Pepco	93.5	372.0	105.3	85.5	19.8	28.3%	23.0%
PPL	488.2	621.1	228.8	139.6	89.2	36.8%	22.5%
PSEG	188.1	350.6	104.7	71.0	33.7	29.9%	20.2%
RECO	3.4	4.0	3.0	2.9	0.1	74.3%	71.1%
Weighted Total	4,264.2	5,923.0	2,079.5	1,594.6	413.9	35.1%	26.9%

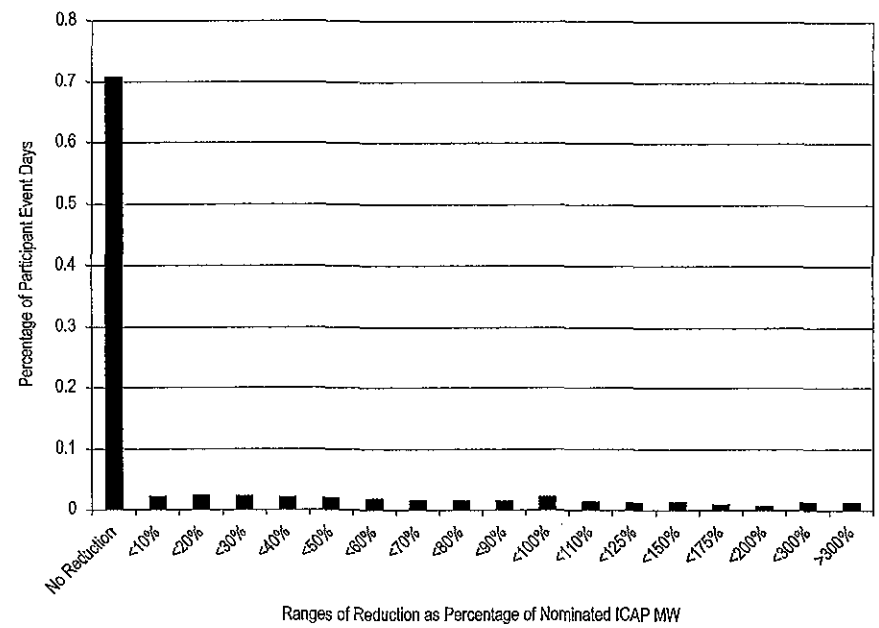
Performance for specific customers varied significantly. Table 6-24 shows the distribution of participant event days across various levels of performance for January 7, January 8, January 22, January 23 and January 24, 2014, events in the 2013/2014 compliance period. Table 6-24 includes the participation for all resources dispatched for the emergency events. For these events, 71 percent of participant event days showed no reduction, load increased or participants did not report data. Approximately 82 percent of participant event days provided less than half of their nominated MW, while 80 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, approximately 91 percent, provided less than 100 percent reduction compared to their nominated MW, while 91 percent of the nominated MW provided less than 100 percent reduction.

Table 6-24 Distribution of participant event days and nominated MW across ranges of performance levels across the events: January through March; 2014

Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of Nominated MW
0%, load increase, or no reporting	50,127	70.9%	32,400	67.0%
0% - 10%	1,604	2.3%	1,379	2.9%
10% - 20%	1,770	2.5%	1,421	2.9%
20% - 30%	1,702	2.4%	1,433	3.0%
30% - 40%	1,511	2.1%	1,158	2.4%
40% - 50%	1,434	2.0%	1,007	2.1%
50% - 60%	1,371	1.9%	1,065	2.2%
60% - 70%	1,210	1.7%	910	1.9%
70% - 80%	1,149	1.6%	982	2.0%
80% - 90%	1,095	1.5%	766	1.6%
90% - 100%	1,612	2.3%	1,676	3.5%
100% - 110%	1,035	1.5%	1,569	3.2%
110% - 125%	947	1.3%	685	1.4%
125% - 150%	993	1.4%	592	1.2%
150% - 175%	733	1.0%	357	0.7%
175% - 200%	511	0.7%	258	0.5%
200% - 300%	956	1.4%	436	0.9%
> 300%	982	1.4%	295	0.6%
Total	70,742	100.0%	48,389	100.0%

Figure 6-3 shows the data in Table 6-24.[14] *The distribution illustrates* high frequencies of underperforming registrations, and very few resources performing at or above 100 percent.

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



14 Participant event days, shown in Figure 6-3, and Table 6-24, 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.

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 within demand response portfolios. A resource that has load above their baseline during a demand response event has a calculated negative performance value. PJM limits compliance shortfall values at the nominated MW value for underperformance. This is not explicitly stated in the Tariff or supporting Manuals. According to the Tariff, the compliance formulas for FSL and GLD customers allow for negative compliance values. For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when dalled, compliance for that registration is calculated as a 75 MWh load reduction for that event hour. Settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would show a 0 MWh reduction in hour one and a 30 MWh reduction in hour two and an average hourly 15 MWh load reduction for that two hour event. Reported compliance is less than actual compliance, as locations with load increases, negative reductions, are treated as zero for compliance purposes. Overall, 71 percent of event hours demonstrated negative reductions or no reduction in load, as shown in Table 6-24.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 59.8 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.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

Table 6-25 shows the number of locations that did not report during the first three months of 2014 event days. In total, 59.8 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 58.1 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 6-25 Non-reporting locations and nominated ICAP on 2014 event days

	Locations Not Reporting	Percent Not Reporting	Nominated ICAP Not Reporting	Percent Not Reporting
Total	42,277	59.8%	28,092	58.1%

Emergency Energy Payments

For any PJM declared load management event in the first three months of 2014, participants registered under the full option of the emergency load response program, which contains 99.6 percent of registrations, that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The emergency energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800 per MWh. The maximum offer 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.[15]

15 139 FERC ¶ 61,057 (2012).

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, 70.5 percent, have a minimum dispatch price of $1,000 per MWh, and 18.8 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 Synchronized Reserve Market, but not the emergency or economic demand response program.[16]

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[17]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	455	3.3%	852.5	8.7%	$0.00
$1-$200	712	5.2%	349.6	3.6%	$2.67
$200-$500	179	1.3%	107.2	1.1%	$171.23
$500-$800	66	0.5%	84.0	0.9%	$3,262.88
$800-$999	56	0.4%	52.9	0.5%	$622.59
$1,000	9,705	70.5%	6,560.3	67.1%	$28.18
$1,800	2,595	18.8%	1,776.3	18.2%	$0.00
Total	13,768	100.0%	9,782.7	100.0%	$40.40

Table 6-27 has the energy reduction MWh and average real-time LMPs during the January demand response event days. The first column shows the hour beginning for each event day. The second column has the MWh reductions, which are calculated by comparing each resource's CBL to their actual load during the demand response event.[18] If a resource is registered for both the economic and emergency program, the economic CBL is used for the emergency CBL. If a resource is only registered under the emergency option, the CBL is the hour before the reductions occur.[19] On January 7, 2014, the whole RTO was called at 430 to reduce at 530 and 630 EPT for short and long lead resources respectively. If a resource could reduce before their designated lead time, that resource was eligible for energy settlements. The average LMP columns consist of the average LMP for each hour of an event day based on what zones were called. The January 22, 2014, event day included only SWMAAC, so the average LMP is the average of the BGE and Pepco zones. The LMP was only greater than $1,000 per MWh for the dispatched areas for three events, both of the January 7 events and the January 22 event.

16 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.
17 In this analysis nominated MW does not include capacity only resources, which do not receive energy market revenue.

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

Table 6-27 Energy reduction MWh and average real-time LMP during demand response event days: 2014

	7-Jan		8-Jan		22-Jan		23-Jan		24-Jan	
Hour Beginning	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)
0		$322		$159		$61		$285		$382
1		$416		$180		$160		$246		$446
2		$423		$170		$186		$283		$520
3		$278		$110		$153		$272		$468
4	464.3	$473		$120		$102	127.8	$283	144.8	$487
5	834.0	$487	447.1	$198		$405	233.9	$204	217.6	$619
6	1,359.8	$1,030	902.7	$329		$312	448.4	$279	484.2	$678
7	1,740.2	$1,726	1,095.6	$291		$558	620.2	$348	578.0	$834
8	1,981.7	$1,833	911.1	$184		$516	544.3	$226	575.2	$540
9	1,955.2	$1,784		$214		$460		$124		$426
10	1,799.9	$1,772		$200		$503		$272		$361
11		$1,434		$216		$514		$502		$278
12		$406		$101		$463		$396		$295
13		$496		$121		$275		$489		$313
14		$328		$42	10.9	$274	423.7	$588		$251
15	1,247.9	$244		$96	37.6	$1,207	588.0	$566		$145
16	1,802.5	$292		$131	93.7	$467	905.6	$354		$207
17	2,346.9	$1,018		$182	108.0	$1,819	930.7	$477		$398
18	2,227.9	$438		$117	133.0	$1,817	957.1	$553		$283
19		$438		$128	154.0	$1,825		$623		$276
20		$355		$156	159.3	$1,749		$708		$396
21		$259		$101		$593		$647		$371
22		$215		$65		$470		$628		$145
23		$211		$40		$359		$493		$230
Total	17,760.0	$695	3,356.4	$152	696.6	$635	5,779.7	$410	1,999.7	$390

Table 6-28 shows emergency credits for each event in 2014. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the Real-Time Energy Market.[20] Emergency demand response energy costs are not covered by LMP. All demand response energy payments and shutdown costs are out of market payments. These payments are a form of uplift.

The events on January 7, 2014, were the first voluntary events of 2014, and the entire RTO was called for both events. January 7 had the most MWh reductions and highest average LMP which resulted in the total emergency credits of $22,691,122. The total emergency credits for the voluntary emergency event days in the first three months of 2014 were $37,146,554.

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.[21]

Table 6-28 Emergency credits by event: 2014

Event Date	Total
7-Jan-14	$22,691,122
8-Jan-14	$3,536,061
22-Jan-14	$1,210,678
23-Jan-14	$7,076,824
24-Jan-14	$2,631,869
Total	$37,146,554

Limited Demand Resource Penalty Charge

Limited demand response resources are required to be available for only 10 times during the months of June through September in a delivery year on weekdays other than PJM holidays from 1200 (EPT) to 2000 (EPT) and be capable of maintaining an interruption for a minimum of two hours to a maximum of six hours. Limited demand response resources have one or two hours to reduce load once PJM initiates an event. When a provider under complies based on their committed MW, a 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 and events outside of the June through September window were voluntary, so there were no penalties assessed based on events that occurred during the first three months of 2014. The penalties are assessed daily and have increased by $12,001,510.43 from $1,697,152.96 in June through March of the 2012/2013 Delivery Year compared to $13,698,663.39 of the same period in the 2013/2014 Delivery Year. Table 6-29 shows penalty charges by zone for June through March 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.[22] The penalty charges represent 3.0 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.

20 PJM. "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 69.
21 The emergency energy payments for the first quarter events are not available at date of publication.
22 Refer to Section 5: Capacity, Table 5-11 for complete listing of capacity prices.

Table 6-29 Penalty charges per zone: June through March 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$76.00	$94,390.74
AEP	$119,517.60	$439,541.25
APS	$0.00	$0.00
ATSI	$0.00	$860,795.97
BGE, Met-Ed, Pepco	$528,671.20	$1,838,542.59
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$49,156.80	$231,037.77
DPL	$616,958.88	$572,013.03
DLCO	$0.00	$55,950.42
EKPC	$0.00	$0.00
JCPL	$4,441.44	$449,234.58
PECO	$332,655.04	$4,548,577.56
PENELEC	$36,701.92	$323,111.97
PPL	$495.52	$2,781,356.16
PSEG, RECO	$8,478.56	$1,504,111.35
Total	$1,697,152.96	$13,698,663.39

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- The net revenues reported are theoretical energy and ancillary net revenues and do not include capacity market revenues.
- Energy net revenues are significantly affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first quarter of 2014 than in the first quarter of 2013.
- Although higher energy prices increase net revenues and higher fuel costs decrease net revenues, the net result was substantial increases in net revenues for all technology types in the first three months of 2014 compared to the first three months of 2013. Energy net revenues increased by 1,444 percent for a new CT, 377 percent for a new CC, 637 percent for a new CP, 9,293 percent for a new DS, 188 percent for a new nuclear plant, 54 percent for a new wind installation, and 33 percent for a new solar installation.

Conclusion

Wholesale electric power markets are affected by externally imposed *reliability requirements. A regulatory authority external to the market makes* a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of shortage pricing hours can significantly increase net revenues. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

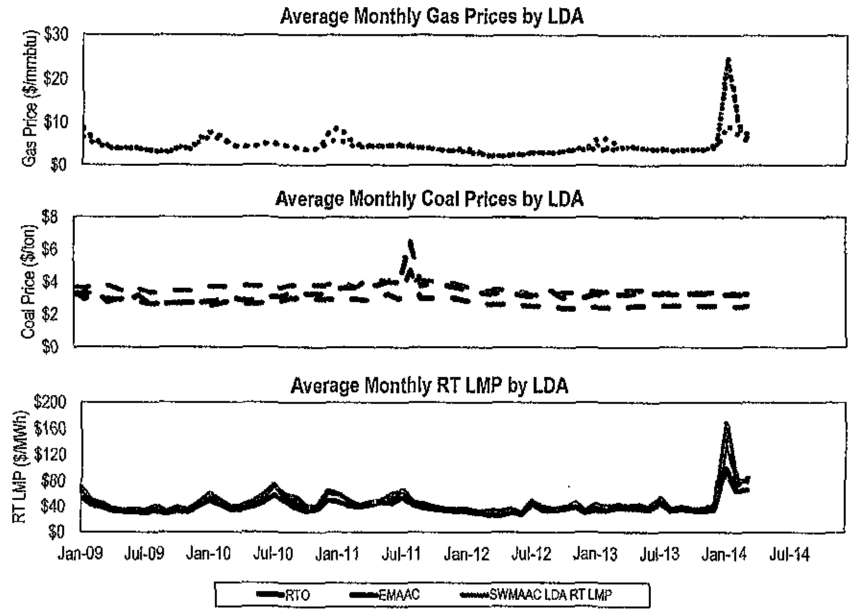
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Operating reserve (uplift) payments are included when the analysis is based on the peak-hour, economic dispatch model and when the analysis uses actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 148.5 percent higher in the first quarter of 2014 than in the first quarter of 2013, $92.98 per MWh versus $37.41 per MWh. Comparing fuel prices in the first quarter of 2014 to the first quarter of 2013, the price of Northern Appalachian coal was 3.7 percent higher; the price of Central Appalachian coal was 4.6 percent lower; the price of Powder River Basin coal was 8.3 percent higher; the price of eastern natural gas was 160.2 percent higher; and the price of western natural gas was 81.1 percent higher.

1 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

Figure 7-1 Energy Market net revenue factor trends: 2009 through March 2014



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on this economic dispatch scenario.

Analysis of energy market net revenues for a new entrant includes eight power plant configurations:

- The CT plant has an installed capacity of 410.2 MW and consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.

- The CC plant has an installed capacity of 655.7 MW and consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[2]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty GE 2.5 MW wind turbines totaling 50 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[3,4] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[5]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[6] Each CT, CC, CP, and DS plant was also given a continuous 14 day planned annual outage in the fall season. Ancillary service revenues for the provision of synchronized reserve service for all four plant types are set to zero. Ancillary service revenues for the provision of regulation service were calculated for the CP only. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 30 or fewer operating years.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[7] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[8] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[9]

2 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
3 Hourly ambient conditions supplied by Schneider Electric.
4 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.
5 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

6 Outage figures obtained from the PJM eGADS database.
7 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
8 Gas daily cash prices obtained from Platts.
9 Coal prompt prices obtained from Platts.

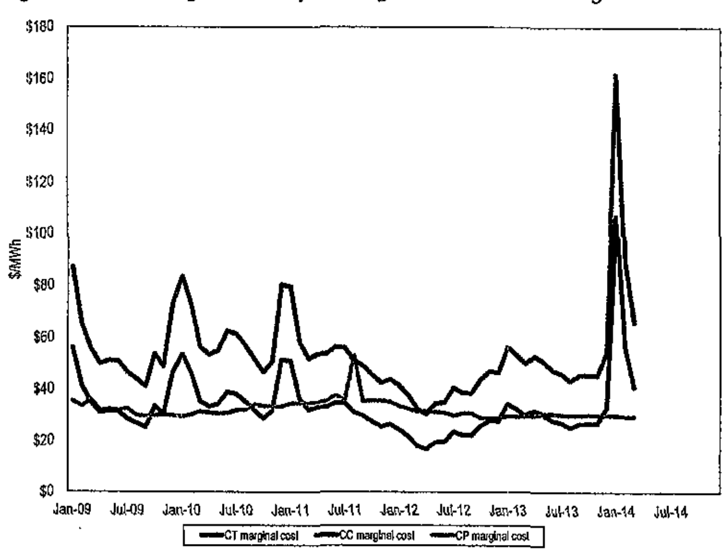
Operating costs are the marginal cost of operations and include fuel costs,[10] emissions costs, and VOM costs.[11] Average zonal operating costs in the first three months of 2014 are shown in Table 7-1.

Table 7-1 Average zonal operating costs: January through March, 2014

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$106.19	10,241	$8.59
CC	$68.68	7,127	$1.50
CP	$29.83	9,250	$3.32
DS	$224.35	9,660	$12.50
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A significant increase in gas prices on cold days in January resulted in a corresponding increase in the average zonal operating cost of CTs and CCs in the first three months of 2014 (Figure 7-2).

Figure 7-2 Average zonal operating costs: 2009 through March 2014



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs. If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CT plant energy market net revenues were higher in the first three months of 2014 as a result of higher energy market prices which more than offset the higher fuel prices. The net revenue increase was the result of an increase in profitable run hours and a number of very high price hours. The impact of very high energy prices varied by zone. In the BGE Zone, energy net revenues generated during hours in which the real-time LMP was greater than or equal to $500 accounted for 26.6 percent of all CT energy net revenues. In the PENELEC Zone, energy net revenues generated during hours in which the real-time LMP was greater than or equal to $500 accounted for only 3.7 percent of all CT energy net revenues. The increase in run hours occurred across all zones, although run hours in the first three months of 2014 were substantially higher in some zones, the PENELEC Zone for example, as a result of the combination of natural gas prices and energy prices. (Table 7-2.)

10 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
11 VOM rates provided by Pasteris Energy, Inc.

Table 7-2 Run hours: January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
AECO	295	811	175%
AEP	274	799	192%
AP	328	949	189%
ATSI	276	903	227%
BGE	359	788	119%
ComEd	122	371	204%
DAY	228	766	236%
DEOK	184	775	321%
DLCO	213	716	236%
Dominion	349	732	110%
DPL	259	897	246%
EKPC	NA	761	NA
JCPL	416	803	93%
Met-Ed	277	747	170%
PECO	230	767	233%
PENELEC	493	1,278	159%
Pepco	384	776	102%
PPL	246	759	209%
PSEG	267	729	173%
RECO	369	758	105%

Table 7-3 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[12]: January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
AECO	$3,503	$48,830	1,294%
AEP	$1,666	$46,337	2,682%
AP	$2,936	$64,737	2,105%
ATSI	$1,717	$52,926	2,982%
BGE	$5,139	$56,876	1,007%
ComEd	$1,356	$28,526	2,004%
DAY	$1,373	$46,001	3,250%
DEOK	$1,137	$43,102	3,692%
DLCO	$1,664	$41,230	2,378%
Dominion	$3,741	$43,458	1,062%
DPL	$3,701	$55,446	1,398%
EKPC	NA	$44,913	NA
JCPL	$5,596	$52,025	830%
Met-Ed	$3,548	$48,005	1,253%
PECO	$3,234	$49,058	1,417%
PENELEC	$3,902	$77,679	1,891%
Pepco	$5,475	$56,228	927%
PPL	$3,356	$47,989	1,330%
PSEG	$2,530	$42,817	1,592%
RECO	$5,278	$43,119	717%
PJM	$3,203	$49,465	1,444%

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs.[13] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CC plant energy market net revenues were higher in the first three months of 2014 because of higher energy market prices which more than offset the higher natural gas prices. The number of run hours for the new

12 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
13 All starts associated with combined cycle units are assumed to be hot starts.

entrant CC for the first three months of 2014 was not significantly different than the run hours for the first three months of 2013 but profit margins were higher in the first three months of 2014.

Table 7-4 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
AECO	$16,662	$88,967	434%
AEP	$17,329	$76,395	341%
AP	$20,452	$100,833	393%
ATSI	$18,548	$86,105	364%
BGE	$21,449	$92,437	331%
ComEd	$8,283	$40,085	384%
DAY	$17,819	$75,559	324%
DEOK	$14,571	$72,147	395%
DLCO	$14,225	$64,736	355%
Dominion	$19,789	$75,919	284%
DPL	$18,067	$93,812	419%
EKPC	NA	$73,162	NA
JCPL	$20,399	$95,063	366%
Met-Ed	$16,008	$85,781	436%
PECO	$14,836	$87,065	487%
PENELEC	$24,846	$120,706	386%
Pepco	$21,397	$94,901	344%
PPL	$14,984	$86,338	476%
PSEG	$13,683	$78,575	474%
RECO	$18,539	$77,457	318%
PJM	$17,468	$83,302	377%

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

New entrant CP plant energy market net revenues were higher in the first three months of 2014 because of higher energy market prices. The number of profitable hours in the first three months of 2014 was significantly greater than the number of profitable hours in the first three months of 2013.

Table 7-5 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
AECO	$9,415	$138,166	1,368%
AEP	$20,212	$86,950	330%
AP	$22,902	$107,393	369%
ATSI	$21,518	$95,830	345%
BGE	$11,201	$147,424	1,216%
ComEd	$14,382	$70,257	388%
DAY	$21,831	$87,210	299%
DEOK	$18,508	$80,785	336%
DLCO	$3,148	$58,544	1,760%
Dominion	$28,760	$136,977	376%
DPL	$8,218	$155,631	1,794%
EKPC	NA	$76,737	NA
JCPL	$12,032	$145,210	1,107%
Met-Ed	$8,946	$135,740	1,417%
PECO	$8,274	$137,210	1,558%
PENELEC	$27,094	$117,111	332%
Pepco	$11,423	$144,090	1,161%
PPL	$8,322	$136,297	1,538%
PSEG	$22,054	$161,114	631%
RECO	$27,918	$157,791	465%
PJM	$16,114	$118,823	637%

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

New entrant DS plant energy market net revenues were higher in the first three months of 2014 because of higher energy market prices which more than offset the higher fuel prices. The number of profitable hours in the first three months of 2014 was significantly higher than in the first three months of 2013 for a new entrant DS plant.

Table 7-6 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
AECO	$268	$37,651	13,929%
AEP	$101	$16,348	16,093%
AP	$131	$20,995	15,985%
ATSI	$99	$16,040	16,076%
BGE	$608	$56,811	9,249%
ComEd	$75	$12,891	17,038%
DAY	$88	$16,120	18,175%
DEOK	$75	$15,241	20,121%
DLCO	$79	$14,728	18,460%
Dominion	$480	$48,751	10,053%
DPL	$297	$42,718	14,286%
EKPC	NA	$16,365	NA
JCPL	$470	$37,978	7,983%
Met-Ed	$257	$36,851	14,235%
PECO	$258	$37,090	14,253%
PENELEC	$126	$18,495	14,559%
Pepco	$686	$58,981	8,503%
PPL	$261	$37,923	14,416%
PSEG	$335	$37,466	11,100%
RECO	$1,515	$34,610	2,184%
PJM	$327	$30,703	9,293%

Table 7-7 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
AECO	$62,876	$213,108	239%
AEP	$55,901	$133,456	139%
AP	$58,925	$156,581	166%
ATSI	$57,092	$142,752	150%
BGE	$68,893	$223,476	224%
ComEd	$49,260	$114,468	132%
DAY	$56,470	$132,989	136%
DEOK	$52,725	$125,746	138%
DLCO	$52,942	$121,236	129%
Dominion	$65,581	$190,110	190%
DPL	$64,623	$226,731	251%
EKPC	NA	$125,699	NA
JCPL	$66,523	$220,206	231%
Met-Ed	$62,068	$208,680	236%
PECO	$61,055	$210,437	245%
PENELEC	$62,513	$167,500	168%
Pepco	$69,062	$219,810	218%
PPL	$61,099	$209,275	243%
PSEG	$78,420	$237,349	203%
RECO	$85,202	$234,180	175%
PJM	$62,696	$180,689	188%

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

New entrant nuclear energy market net revenues were higher in the first three months of 2014 because of higher energy market prices and correspondingly higher margins.

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power.

New entrant wind energy market net revenues were higher in the first three months of 2014 because of higher energy market prices and correspondingly higher margins. Wind net revenues did not increase as much as other technology types because wind is not dispatchable in response to higher prices.

Table 7-8 Energy Market net revenue for a wind installation (Dollars per installed MW-year): January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
ComEd	$45,590	$66,035	45%
PENELEC	$52,992	$86,579	63%

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG Zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power.

New entrant solar energy market net revenues were higher in the first three months of 2014 because of higher energy market prices and correspondingly higher margins. Like wind, solar net revenues did not increase as much as other technology types because solar is not dispatchable in response to higher prices.

Table 7-9 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year): January through March, 2013 and 2014

Zone	2013 (Jan-Mar)	2014 (Jan-Mar)	Change in 2014 from 2013
PSEG	$108,107	$143,739	33%

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal emissions. The EPA has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The most recent interstate emissions rule, the Cross-State Air Pollution Rule (CSAPR), will, when implemented, also require investments for some fossil-fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from RGGI affect some unit offers in the PJM energy market. The investments required for environmental compliance have resulted in higher offers in the capacity market, and when units do not clear, in the retirement of units.

Renewable energy mandates and associated incentives by state and federal governments have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have potentially significant impacts on PJM wholesale markets.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[2] The rule establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[3]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR), clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[5]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[6] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided

1 For quantification of the economics of new entrant wind and solar installations, see the *2013 State of the Market Report for PJM*, Volume II, Section 7, "Net Revenue."

2 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

3 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

4 CAA § 110(a)(2)(D)(i)(I).

5 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

6 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics.[7]

In PJM's recent filing to improve its ability to dispatch DR prior to emergency system conditions, PJM proposed to retain the PJM Emergency Load Response Program apparently for the sole purpose of allowing RICE to continue to use the EPA's exception.[8] The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[9] An order from the Commission in this matter is now pending.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[10] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[11]

- **Cooling Water Intakes.** Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best available technology for minimizing adverse environmental impacts. A final rule implementing this requirement is expected to be issued by May 16, 2014.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on such high energy demand days.[12] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[13]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2014 for the 2012-2014 compliance period were at $4.00 per ton, above the price floor for 2014. The clearing price is equivalent to a price of $4.41 per metric tonne, the unit used in other carbon markets.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On March 31, 2014, 70.6 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 98.7 percent of coal steam MW had some type of particulate control, and 91.7 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

7 See Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.
8 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2013).
9 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3-6.
10 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495.
11 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).
12 N.J.A.C. § 7:27-19.
13 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2014, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have not enacted renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits (RECs) provide out of market payments to qualifying resources, primarily wind and solar. The out of market payments in the form of RECs and federal production tax credits mean that these units have an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. As the net of marginal cost and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are not transparent. Data on RECs prices and markets are not publicly available. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and certain area sources of emissions.[14,15] The EPA actions have and are expected to continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the Clean Water Act (CWA) affects generating plants that rely on water drawn from jurisdictional water bodies.[16]

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas,

14 42 U.S.C. § 7401 et seq. (2000).

15 The EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

16 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.,* 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.

nickel, selenium and cyanide.[17] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[18]

Air Quality Standards: Control of NO_x, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_x, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as "SIPs." Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and periodically revised accordingly.

Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[19]

On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR), clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[20]

17 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

18 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

19 CAA § 110(a)(2)(D)(i)(I).

20 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

EPA finalized the CSAPR on July 6, 2011. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[21] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[22]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[23] Group 2 does not include any states in the PJM region.[24] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[25] NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

Under the original timetable for implementation, emission reductions were expected to become effective starting January 1, 2012, for SO_2 and annual NO_X reductions and May 1, 2012, for ozone season NO_X reductions. CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

21 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) (CSAPR); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012) (CSAPR II).

22 *Id.*

23 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

24 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

25 EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM ($PM_{2.5}$) measures less than 2.5 microns across.

Under the original implementation timetable, significant additional SO_2 emission reductions would have taken effect in 2014 from certain states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group. Thus, units in PJM states may only trade and use allowances originating in Group 1 states.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty would be assessed that is allocated to resources within the state in proportion to their responsibility for the excess. The penalty would be a requirement to surrender two additional allowances for each allowance needed to the cover the excess.

Because of the delay resulting from judicial review, the initial timetable for implementation is not feasible and must be replaced. In the meantime, EPA advises that CAIR remains in effect and "no immediate action from States or affected sources is expected."[26]

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[27] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[28]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition).

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[29] The proposed rule allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The MMU objected to the proposed rule, as it had to similar provisions in a related proposed settlement released for comment, explaining that it was not required for participation by demand resources in the PJM markets, nor for reliability.[30] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[31] Otherwise a 15-hour exception applies.[32] The exempted emergency demand response programs include demand resources in RPM.[33]

Pending initiatives in Pennsylvania and New Jersey would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics in those jurisdictions.[34] The MMU and PJM have stated that these state measures would not, if enacted,

26 See EPA, "Cross-State Air Pollution Rule (CSAPR)," <http://www.epa.gov/airtransport/CSAPR/>.
27 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("Final NESHAP RICE Rule").
28 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ.
29 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.
30 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).
31 Final NESHAP RICE Rule at 31–24.
32 *Id.* at 31.
33 If FERC approves the PJM Interconnection Docket No. ER14-822-000, demand resources that utilize behind-the-meter generators will maintain emergency status and not have to curtail during pre-emergency events.
34 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

have any harmful impact on system reliability.[35] The MMU has also explained that such measures would improve markets.[36]

On December 24, 2013, PJM filed revisions to the rules providing for a PJM Pre-Emergency Load Response Program that allows PJM to dispatch resources participating in the program with no prerequisite for system emergency conditions.[37] PJM retained the PJM Emergency Load Response Program (ELRP), but proposed to restrict participation in the ELRP to DR based on "generation that is behind the meter and has strict environmental restrictions on when it can operate."[38] Such restrictions refer to the EPA's amended RICE NESHAP Rule. EPA created an exception to and weakened its NESHAP RICE Rule based on arguments that markets such as PJM needed RICE for reliability. PJM created an exception to and weakened its rule intended to enhance reliability in order to avoid interfering with the EPA exception. The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[39] An order from the Commission on PJM's filing is now pending.

Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare.[40] On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[41] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[42]

On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[43] The standards would require advanced technologies like efficient natural gas units and efficient coal units implementing partial carbon capture and storage (CCS). The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[44]

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the CWA.[45] A settlement in a federal court, as modified, obligates the EPA to issue a final

35 *See* Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-0708 (August 9, 2012); Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012); Market Monitor, Comments of the Independent Market Monitor for PJM, Supporting Testimony before the Pennsylvania House of Representatives Environmental and Energy Committee re House Bill 1699, An Act Providing for the Regulation of Certain Reciprocal Internal Combustion Engines (November 20, 2013), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_to_PA_CERE_1699_20131120.pdf>; Letter from Terry Boston, President & CEO, PJM to Hon. Chris Ross re Pennsylvania House Bill 1999 (November 11, 2013) ("With regards to your inquiry of potential impacts to grid reliability, PJM does not anticipate the emergence of system reliability issues, should HB 1699 become law."); Letter from Terry Boston, President & CEO, PJM to Hon. Mary M. Cheh re District of Columbia Bill 20-569 (December 19, 2013).

36 *Id.*

37 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2014).

38 *Id.* at 8–9.

39 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3–6.

40 Massachusetts v. EPA, 549 U.S. 497.

41 *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009).

42 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

43 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013); Presidential Memorandum-Power Sector Carbon Pollution Standards, Environmental Protection Agency ("June 25, 2013); Presidential Memorandum-Power Section Caron Pollution Standards (June 25, 2013) (June 25th Presidential Memorandum").

44 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660, 79 Fed. Reg. 1352 (January 8, 2014).

45 EPA, *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule*, Docket No. EPA-HQ-OW-2008-0667, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).

rule no later than April 17, 2014.[46] By letter dated April 16, 2014, EPA notified the court of its intention to complete the rulemaking by May 16, 2014.[47]

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[48] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[49]

Table 8-1 shows the HEDD emissions limits applicable to each unit type. Emissions limits for coal units became effective December 15, 2012.[50] Emissions limits for other unit types will become effective May 1, 2015.[51]

Table 8-1 HEDD maximum NOx emission rates[52]

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[53,54]

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional auctions for the 2012-2014 compliance period held as of December 31, 2013. Prices for auctions held in 2014 for the 2012-2014 compliance period were at the highest clearing price yet at $4.00 per allowance (equal to one ton of CO_2), which is above the current price floor for RGGI auctions.[55] The price increased to $4.00 due to a 45 percent reduction in the quantity offered in this auction. The 23,491,350 allowances sold include the original allowances offered for sale in the market of 18,491,350 as well as 5,000,000 additional cost containment reserves (CCR). This auction included the additional CCRs for the first time, due to the demand for allowances above the CCR trigger price of $4.00 per ton. There are no additional CCRs available for sale in 2014. Table 8-3 converts the RGGI CO_2 clearing prices and quantities to metric tonnes for comparison to other CO_2 markets.

46 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010, modified, Fifth Amendment to Settlement Agreement among the Environmental Protection Agency, the Plaintiffs in Cronin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and the Plaintiffs in Riverkeeper, et al. v. EPA, 06 Civ. 12987 (PKC) (SDNY), etc.
47 Letter from Preet Bharara, Counsel for EPA, to the Hon. Laura Taylor Swain, U.S. Dist. Judge, re: Riverkeeper, Inc., et al. v. Jackson, 93 Civ. 324 (LTS), dated April 16, 2014.
48 N.J.A.C. § 7:27-19.
49 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).
50 N.J.A.C. § 7:27-19.4.
51 N.J.A.C. § 7:27-19.5.

52 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.
53 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.
54 For more details see the 2013 State of the Market Report for PJM, Volume 2: Section 8, "Environmental and Renewables."
55 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

Figure 8-1 shows average, daily settled prices for NO_x, CO_2 and SO_2 emissions.[56] In the first three months of 2014, NO_x prices were 5.3 percent higher than in the first three months of 2013. SO_2 prices were 17.2 percent lower in the first three months of 2014 compared to the first three months of 2013. Figure 8-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware and Maryland.

Figure 8-1 Spot monthly average emission price comparison: 2013 and January through March of 2014[57]

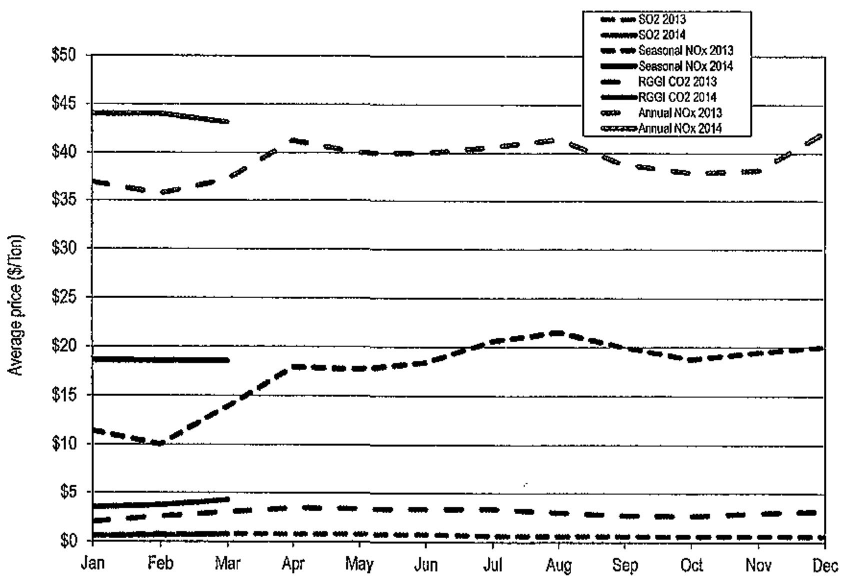


Table 8-2 RGGI CO2 allowance auction prices and quantities in short tons: 2009-2011 and 2012-2014 Compliance Periods[58]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000
March 14, 2012	$1.93	34,843,858	21,559,000
June 6, 2012	$1.93	36,426,008	20,941,000
September 5, 2012	$1.93	37,949,558	24,589,000
December 5, 2012	$1.93	37,563,083	19,774,000
March 13, 2013	$2.80	37,835,405	37,835,405
June 5, 2013	$3.21	38,782,076	38,782,076
September 4, 2013	$2.67	38,409,043	38,409,043
December 4, 2013	$3.00	38,329,378	38,329,378
March 5, 2014	$4.00	23,491,350	23,491,350

56 The NO_x prices result from the Clean Air Interstate Rule (CAIR) established by the EPA covering 28 states. The SO_2 prices result from the Acid Rain cap and trade program established by the EPA. The CO_2 prices are from RGGI.

57 See *Evolution Markets*, <http://www.evomarkets.com> (Accessed April 8, 2014).

58 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed April 8, 2014).

Table 8-3 RGGI CO2 allowance auction prices and quantities in metric tonnes: 2009-2011 and 2012-2014 Compliance Periods[59]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.38	11,399,131	11,399,131
December 17, 2008	$3.73	28,581,678	28,581,678
March 18, 2009	$3.87	28,588,815	28,588,815
June 17, 2009	$3.56	28,020,786	28,020,786
September 9, 2009	$2.41	25,772,169	25,772,169
December 2, 2009	$2.26	25,937,960	25,937,960
March 10, 2010	$2.28	36,842,967	36,842,967
June 9, 2010	$2.07	36,909,352	36,909,352
September 10, 2010	$2.05	41,363,978	31,213,514
December 1, 2010	$2.05	39,166,486	22,457,365
March 9, 2011	$2.08	38,097,972	38,097,972
June 8, 2011	$2.08	38,132,781	11,373,378
September 7, 2011	$2.08	38,273,849	7,118,681
December 7, 2011	$2.08	38,993,970	24,759,800
March 14, 2012	$2.13	31,609,825	19,558,001
June 6, 2012	$2.13	33,045,128	18,997,361
September 5, 2012	$2.13	34,427,270	22,306,772
December 5, 2012	$2.13	34,076,665	17,938,676
March 13, 2013	$3.09	34,323,712	34,323,712
June 5, 2013	$3.54	35,182,518	35,182,518
September 4, 2013	$2.94	34,844,108	34,844,108
December 4, 2013	$3.31	34,771,837	34,771,837
March 5, 2014	$4.41	21,311,000	21,311,000

Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2014, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2024. As shown in Table 8-4, New Jersey will require 24.1 percent of load to be served by renewable resources in 2024, the most stringent standard of all PJM jurisdictions. Renewable generation earns renewable energy credits (RECs) (also known as alternative energy credits) when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction. For example, Illinois only requires utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are out of market revenues for PJM resources and are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit per MWh for generation from alternative energy resources including waste coal and pumped-storage hydroelectric, and allows two credits per MWh of electricity generated by renewable energy resources, which include wind, solar, and run of river hydroelectric. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits.

59 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed April 8, 2014).

Table 8-4 Renewable standards of PJM jurisdictions to 2024[60,61]

Jurisdiction	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%
Illinois	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	12.80%	13.00%	15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%
Michigan	*6.75%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*	*10.00%*
New Jersey	12.53%	13.76%	14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%
North Carolina	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%
Ohio	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%
Pennsylvania	10.72%	11.22%	13.72%	14.22%	14.72%	15.22%	15.72%	18.02%	18.02%	18.02%	18.02%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%
Washington, D.C.	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	20.00%
West Virginia		10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%	15.00%	15.00%

Table 8-5 Pennsylvania weighted average AEC price and AEC price range for 2010 to 2014 Delivery Years[62]

	2010/2011 Delivery Year		2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
Pennsylvania	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range
Solar AEC	$325.00	$235.00-$415.00	$247.82	$25.00-$653.00	$180.39	$10.00-$675.00	$109.23	$5.50-$600.00
Tier I	$4.77	$0.50-$24.15	$3.94	$0.14-$50.00	$5.23	$0.20-$23.00	$8.31	$0.13-$100.00
Tier II	$0.32	$0.01-$1.75	$0.22	$0.01-$20.00	$0.17	$0.01-$5.00	$0.22	$0.01-$20.00

REC prices are required to be disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are difficult to determine. Few sources provide public REC price data. Table 8-5 has the Pennsylvania weighted average price and price range for 2010 through 2014 delivery years. The weighted average price of solar credits in Pennsylvania decreased from $325.00 in the 2010/2011 Delivery Year to $109.23 in the 2013/2014 Delivery Year. Tier I credits increased from $4.77 in the 2010/2011 Delivery year to $8.31 in the 2013/2014 Delivery Year, while Tier II resources dropped $0.10 from $0.32 in the 2010/2011 Delivery Year to $0.22 in the 2013/2014 Delivery Year.[63]

Many PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the standards shown in Table 8-4 but must be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have requirements for the proportion of load served by solar units by 2023.[64] Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. In 2014, New Jersey had the most stringent standard in PJM, requiring that 2.05 percent of load be served by solar resources. As Table 8-6 shows, by 2024, New Jersey will continue to have the most stringent standard, requiring that at least 3.74 percent of load be served by solar resources.

60 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.
61 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.
62 See PAPUC. Pennsylvania AEPS Alternative Energy Credit Program, "Pricing," <http://paaeps.com/credit/pricing.do> (Accessed April 8, 2014).
63 Tier I resources are solar photovoltaic and thermal energy, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, biomass and coal mine methane. Tier II resources are waste coal, distributed generation, demand-side management, large-scale hydropower, municipal solid waste and integrated combined coal gasification technology.
64 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement.

Table 8-6 Solar renewable standards of PJM jurisdictions 2014 to 2024

Jurisdiction	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%
Illinois	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%
North Carolina	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%
Pennsylvania	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.50%
West Virginia	No Solar Standard										

Table 8-7 Additional renewable standards of PJM jurisdictions 2014 to 2024

Jurisdiction		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Illinois	Wind Requirement	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%
Illinois	Distributed Generation	0.04%	0.68%	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Garve-Out (in GWh)	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433	3,989
North Carolina	Swint Waste	0.07%	14.00%	14.00%	14.00%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have also added other specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-7 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind resources, increasing from 6.00 percent of load served in 2014 to 16.50 percent in 2024. Maryland, New Jersey, Pennsylvania and Washington D.C. all have "Tier II" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits.[65] North Carolina also requires that 0.2 percent of power be generated using swine waste and poultry waste to fulfill their renewable portfolio standards by 2018 (Table 8-7).

PJM jurisdictions include various methods for complying with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $339.00 per MWh.[66] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. Standard alternative compliance payments can replace solar, wind energy, organic biomass and hydro power. Table 8-8 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

65 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

66 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/Policies for Renewables & Efficiency, "Renewables Portfolio Standard," <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed April 8, 2013).

Table 8-8 Renewable alternative compliance payments in PJM jurisdictions: As of March 31, 2014[67]

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$339.00
North Carolina	No specific penalties		
Ohio	$47.56		$350.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 8-9 shows renewable generation by jurisdiction and resource type in the first three months of 2014. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 4,811.0 GWh of 7,464.7 Tier I GWh, or 64.4 percent, in the PJM footprint. As shown in Table 8-9, 13,542.5 GWh were generated by resources that were renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 55.1 percent. Landfill gas, solid waste, and waste coal were 4,950.7 GWh of renewable generation or 36.6 percent of the total Tier I and Tier II.

Table 8-9 Renewable generation by jurisdiction and renewable resource type (GWh): January through March 2014

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	13.2	0.0	0.0	0.0	0.0	0.0	0.0	13.2	26.3
Illinois	44.3	0.0	0.0	0.0	0.0	0.0	1,970.5	2,014.7	2,014.7
Indiana	0.0	0.0	12.0	0.0	0.0	0.0	766.5	778.4	778.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	24.6	0.0	500.1	11.9	0.0	0.0	103.7	640.2	640.2
Michigan	6.5	0.0	16.7	0.0	0.0	0.0	0.0	23.2	23.2
New Jersey	79.7	151.8	4.9	39.5	0.0	0.0	3.5	127.5	279.3
North Carolina	0.0	0.0	236.1	0.0	0.0	0.0	0.0	236.1	236.1
Ohio	82.5	0.0	96.7	0.7	0.0	0.0	363.0	542.8	542.8
Pennsylvania	202.6	608.9	575.4	0.3	77.4	2,674.2	1,083.7	1,862.0	5,222.4
Tennessee	0.0	0.0	0.0	0.0	84.7	0.0	0.0	0.0	84.7
Virginia	118.5	939.8	185.2	0.0	313.2	967.2	0.0	303.7	2,524.0
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	1.8	0.0	400.8	0.0	0.0	260.5	520.2	922.9	1,183.3
Total	573.5	1,700.6	2,028.0	52.3	475.3	3,901.9	4,811.0	7,464.7	13,542.5

Table 8-10 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[68] This capacity includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. Coal and natural gas units are considered to generate renewable energy only when generating using a renewable fuel, like waste coal in West Virginia. West Virginia has the largest amount of renewable capacity in PJM, 10,254.7 MW, or 22.7 percent of the total renewable capacity. West Virginia allows coal technology, coal bed methane, waste coal and fuel produced by a coal gasification facility to be counted as alternative energy resources. New Jersey has the largest amount of solar capacity in PJM, 180.5 MW, or 75.7 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,635.7 MW, or 58.0 percent of the total wind capacity.

67 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis/program-information.aspx>. (Accessed April 8, 2014)

68 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 8-10 PJM renewable capacity by jurisdiction (MW), on March 31, 2014

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,797.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	79.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,383.4	2,462.9
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,252.4	1,260.6
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	25.1	0.0	69.0	0.0	494.0	48.8	0.0	0.0	120.0	757.0
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
New Jersey	0.0	86.5	0.0	0.0	453.0	3.5	180.5	0.0	0.0	4.5	728.1
North Carolina	0.0	0.0	0.0	0.0	0.0	325.0	0.0	0.0	0.0	0.0	325.0
Ohio	11,613.0	64.7	580.0	156.0	0.0	47.4	1.1	0.0	0.0	403.0	12,865.2
Pennsylvania	0.0	222.0	2,346.0	0.0	1,269.0	757.3	8.0	103.0	1,647.0	1,337.7	7,690.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	214.9	0.0	20.0	5,166.2	350.5	0.0	321.9	585.0	0.0	6,658.5
West Virginia	8,772.0	2.2	519.0	0.0	0.0	213.2	0.0	0.0	165.0	583.3	10,254.7
PJM Total	20,385.0	711.0	5,242.0	258.0	6,888.2	2,213.0	238.5	474.9	2,397.0	6,269.2	45,076.9

Table 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS[69,70] (MW), on March 31, 2014

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	53.3	0.0	2.1	55.4
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	258.9	0.0	258.9
Illinois	0.0	6.6	92.4	0.0	0.0	0.0	34.5	0.0	302.5	436.1
Indiana	0.0	0.0	44.0	584.5	6.0	94.6	1.4	0.0	49.5	780.1
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	600.0	2.0	16.0	0.0	0.0	0.0	0.6	88.0	0.0	706.6
Maryland	65.0	0.0	13.7	129.0	0.0	0.0	112.1	0.0	0.3	320.2
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	59.9	0.0	8.3	23.3	953.3	0.0	4.9	1,049.8
New York	0.0	146.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	147.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	8.6	0.0	0.0	8.6
Ohio	0.0	1.0	30.4	119.6	9.4	1.0	93.9	109.3	21.9	386.5
Pennsylvania	109.7	37.0	41.7	91.0	1.4	0.3	179.4	60.0	3.2	523.7
Virginia	0.0	17.4	15.9	0.0	0.0	0.0	6.2	287.6	0.0	327.1
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	42.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0	43.8
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	8.8	0.0	0.0	8.8
Total	829.7	261.7	315.7	924.2	25.1	119.2	1,455.1	848.4	715.5	5,494.6

69 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
70 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/reports-and-news/public-reports.aspx> (Accessed April 8, 2013).

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS), a system operated by PJM EIS. This includes solar capacity of 1,455.1 MW of which 953.3 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 8-11 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind-the-meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. Many PJM units burning fossil fuels have installed emission control technology.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low SO_2 emission rates. Of the current 70,153.8 MW of coal capacity in PJM, 55,443.3 MW of capacity, 68.6 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-12 shows SO_2 emission controls by fossil fuel units in PJM.[71]

Table 8-12 SO_2 emission controls (FGD) by fuel type (MW), as of March 31, 2014

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	49,788.0	20,365.8	70,153.8	71.0%
Diesel Oil	0.0	6,093.8	6,093.8	0.0%
Natural Gas	0.0	50,892.8	50,892.8	0.0%
Other	325.0	7,412.5	7,737.5	4.2%
Total	50,113.0	84,764.9	134,877.9	37.2%

NO_x emission control technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 123,728.1 MW, 91.7 percent, of 134,877.9 MW of capacity in PJM, have emission controls for NO_x. Table 8-13 shows NO_x emission controls by unit type in PJM. While most units in PJM have NO_x emission controls, many of these controls will likely need to be upgraded in order to meet each state's emission compliance standards. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 8-13 NO_x emission controls by fuel type (MW), as of March 31, 2014

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	68,739.2	1,414.6	70,153.8	98.0%
Diesel Oil	1,456.8	4,637.0	6,093.8	23.9%
Natural Gas	49,333.4	1,559.4	50,892.8	96.9%
Other	4,198.7	3,538.8	7,737.5	54.3%
Total	123,728.1	11,149.8	134,877.9	91.7%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter from coal steam units. In PJM, 69,219.8 MW, 98.7 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 8-14 shows particulate emission controls by unit type in PJM. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet each state's emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which 177 of 229 coal steam units have not installed.

Table 8-14 Particulate emission controls by fuel type (MW), as of March 31, 2014

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	69,219.8	934.0	70,153.8	98.7%
Diesel Oil	0.0	6,093.8	6,093.8	0.0%
Natural Gas	174.0	50,718.8	50,892.8	0.3%
Other	3,159.0	4,578.5	7,737.5	40.8%
Total	72,552.8	62,325.1	134,877.9	53.8%

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 8-15 shows the estimated emissions from units in PJM in the first three months of 2014. It is estimated that over 166 million metric tons of CO_2, 368 thousand metric tons of SO_2, and 293 thousand tons of NO_x were emitted in the first three months of 2014 by PJM units.

71 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/>. (Accessed April 8, 2014)

Table 8-15 CO_2, SO_2 and NO_x emissions by month (metric tons), by PJM units, January through March, 2014

	Tons of CO_2	Tons of SO_2	Tons of NO_x
January	59,789,898.3	132,134.4	105,954.6
February	53,607,987.6	119,625.8	94,816.6
March	52,912,695.5	116,233.8	92,092.4
Total	166,310,581.3	367,994.0	292,863.6

Wind Units

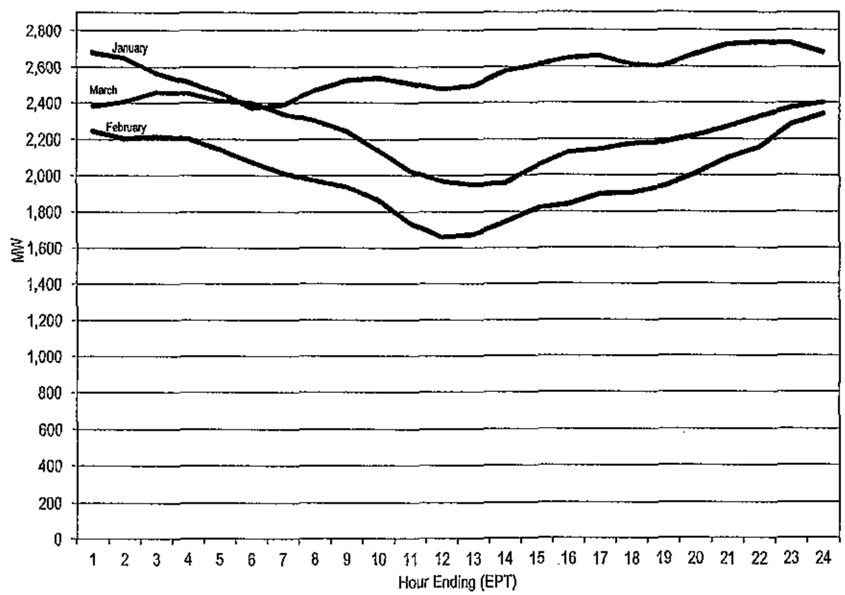
Table 8-16 shows the capacity factor of wind units in PJM. In the first three months of 2014, the capacity factor of wind units in PJM was 38.0 percent. Wind units that were capacity resources had a capacity factor of 38.8 percent and an installed capacity of 4,888 MW. Wind units that were classified as energy only had a capacity factor of 35.4 percent and an installed capacity of 1,476 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[72]

Table 8-16 Capacity factor of wind units in PJM: January through March 2014[73]

Type of Resource	Capacity Factor	Capacity Factor by Cleared MW	Installed Capacity (MW)
Energy-Only Resource	35.4%	NA	1,476
Capacity Resource	38.8%	245.7%	4,888
All Units	38.0%	245.7%	6,364

Figure 8-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,732.2 MW, occurred in January, and the lowest average hour, 1,658.7 MW, occurred in February. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-2 Average hourly real-time generation of wind units in PJM: January through March, 2014



72 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
73 Capacity factor does not include external resources which only offer in the Day - Ahead Market. Capacity factor is calculated based on online date of the resource. Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

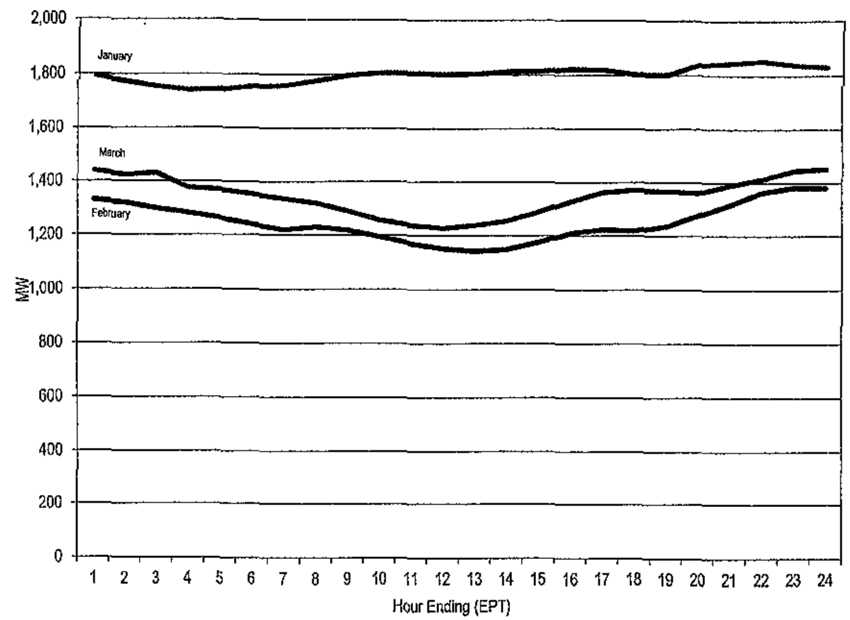
Table 8-17 shows the generation and capacity factor of wind units in each month of the first three months of 2013 and the first three months of 2014.

Table 8-17 Capacity factor of wind units in PJM by month, 2013 and January *through March 2014*

	2013		2014	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,784,359.3	40.3%	1,918,441.4	42.7%
February	1,397,468.3	35.4%	1,342,055.5	33.4%
March	1,606,248.3	36.5%	1,661,382.1	37.3%
April	1,639,590.9	37.8%		
May	1,271,272.4	28.5%		
June	862,532.2	19.8%		
July	588,174.8	13.4%		
August	510,448.5	12.0%		
September	719,196.4	16.7%		
October	1,070,829.4	23.5%		
November	1,833,051.6	41.2%		
December	1,543,685.2	34.2%		
Annual	14,826,857.3	28.3%	4,921,878.9	38.0%

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. Wind units may offer non-capacity related wind energy at their discretion. Figure 8-3 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

Figure 8-3 Average hourly day-ahead generation of wind units in PJM: January through March 2014



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through the first three *months of 2014. Figure 8-4 shows potentially displaced marginal unit MW* by fuel type in the first three months of 2014. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Figure 8-4 Marginal fuel at time of wind generation in PJM: January through March 2014

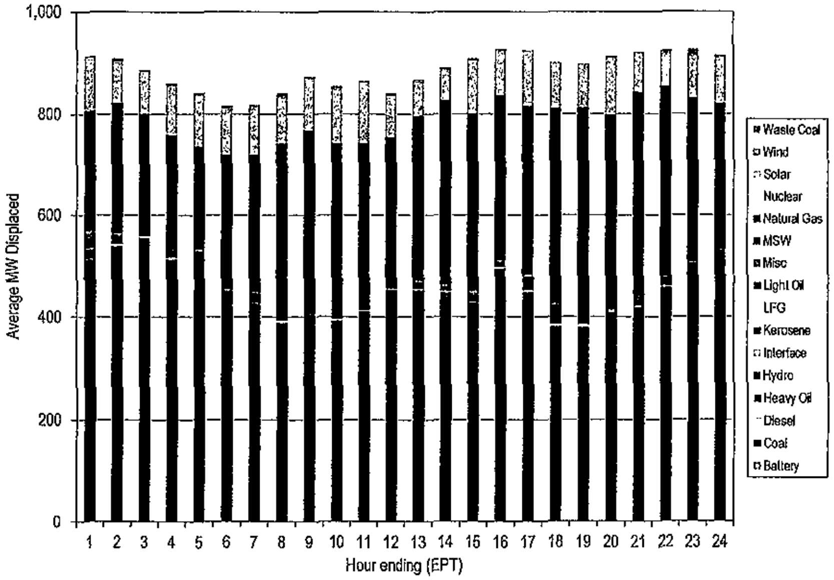
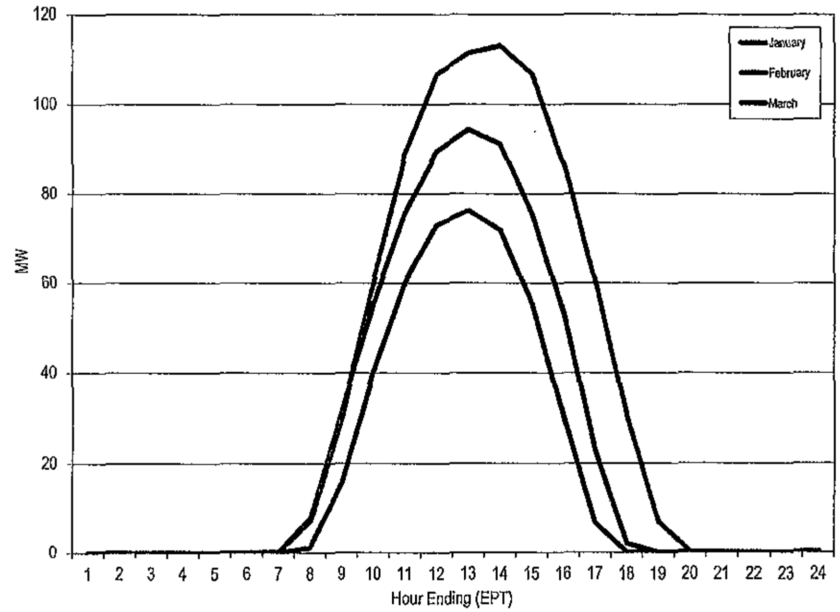


Figure 8-5 Average hourly real-time generation of solar units in PJM: January through March 2014



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-5 shows the average hourly real - time generation of solar units in PJM, by month. Solar generation was highest in March, the month with the highest average hour, 113.14 MW, compared to 238.5 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and non-market balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in February and March.[1] During the first three months of 2014, the real-time net interchange of 240.8 GWh was lower than net interchange of 1,640.5 GWh in the first three months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first three months of 2014, the total day-ahead net interchange of -4,982.0 GWh was lower than net interchange of -6,592.7 GWh during the first three months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2014, gross imports in the Day-Ahead Energy Market were 112.9 percent of gross imports in the Real-Time Energy Market (149.2 percent during the first three months of 2013), gross exports in the Day-Ahead Energy Market were 152.8 percent of the gross exports in the Real-Time Energy Market (243.3 percent during the first three months of 2013).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2014, there were net scheduled exports at 11 of PJM's 18 interface pricing points eligible for real-time transactions.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2014, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first three months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2014, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 48.9 percent of the hours in the first three months of 2014.
- **PJM and New York ISO Interface Prices.** In the first three months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 57.8 percent of the hours in the first three months of 2014.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow in the first three months of 2014 was -518 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 71.4 percent of the hours in the first three month of 2014.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[5] The average hourly flow in the first three months of 2014 was -151 MW.[6] The flows were consistent with price differentials in 65.4 percent of the hours in the first three months of 2014.
- **Hudson DC Line.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[7] The average hourly flow during the first three months of 2014 was -180 MW.[8] The flows were consistent with price differentials in 62.9 percent of the hours in the first three months of 2014.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at one or more specific interfaces.

For the first three months of 2014, net scheduled interchange was -362 GWh and net actual interchange was -243 GWh, a difference of 119 GWh. For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher during the first three months of 2014, compared to eight TLRs issued during the first three months of 2013.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 215,829 bids per day, with an average cleared volume of 1,486,359 MWh per day, in the first three months of 2014, compared to an average of 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013. (Figure 9-13).

Recommendations

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.

3 In the first three months of 2014, there were 198 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $102.11 while the NYISO LMP at the Neptune Bus during non-zero flows was $123.52, a difference of $21.41.
4 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -570 MW.
5 In the first three months of 2014, there were 128 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $102.27 while the NYISO LMP at the Neptune Bus during non-zero flows was $109.82, a difference of $7.55.
6 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Linden VFT line was -160 MW.
7 In the first three months of 2014, there were 841 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $131.57 while the NYISO LMP at the Hudson Bus during non-zero flows was $138.09, a difference of $6.52.
8 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Hudson line was -295 MW.

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first three months of 2014, PJM was a monthly net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in February and March of 2014 (Figure 9-1).[9] For the first three months of 2014, the total real-time net interchange of 240.8 GWh was lower than the net interchange of 1,640.5 GWh during the first three months of 2013. In the first three months of 2014, the peak month for net importing interchange was January, 1,608.8 GWh; in the first three months of 2013 it was February, 639.5 GWh. Gross monthly export volumes during the first three months of 2014 averaged 4,392.7 GWh compared to 3,202.4 GWh for the first three months of 2013, while gross monthly imports in the first three months of 2014 averaged 4,472.9 GWh compared to 3,749.2 GWh for the first three months of 2013.

During the first three months of 2014, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In the first three months of 2014, the total day-ahead net interchange of -4,982.0 GWh was lower than the net interchange of -6,592.7 GWh for the first three months of 2013. In the first three months of 2014, the peak month for net exporting interchange was March, -1,802.8 GWh; in the first three months of 2013 it was January, -2,602.8 GWh. Gross monthly export volumes in the first three months of 2014 averaged 6,711.8 GWh compared to 7,790.7 GWh for the first three months of 2013, while gross monthly imports in the first three months of 2014 averaged 5,051.1 GWh compared to 5,593.1 GWh for the first three months of 2013.

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net Day-Ahead Energy Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 9-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

9 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

In the first three months of 2014, gross imports in the Day-Ahead Energy Market were 112.9 percent of gross imports in the Real-Time Energy Market (149.2 percent for the first three months of 2013), gross exports in the Day-Ahead Energy Market were 152.8 percent of gross exports in the Real-Time Energy Market (243.3 percent for the first three months of 2013). In the first three months of 2014, net interchange was -4,982.0 GWh in the Day-Ahead Energy Market and 240.8 GWh in the Real-Time Energy Market compared to -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market for the first three months of 2013.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW and price differences in the Day-Ahead and Real-Time Energy Markets.[10] In the first three months of 2014, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

10 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: January through March, 2014

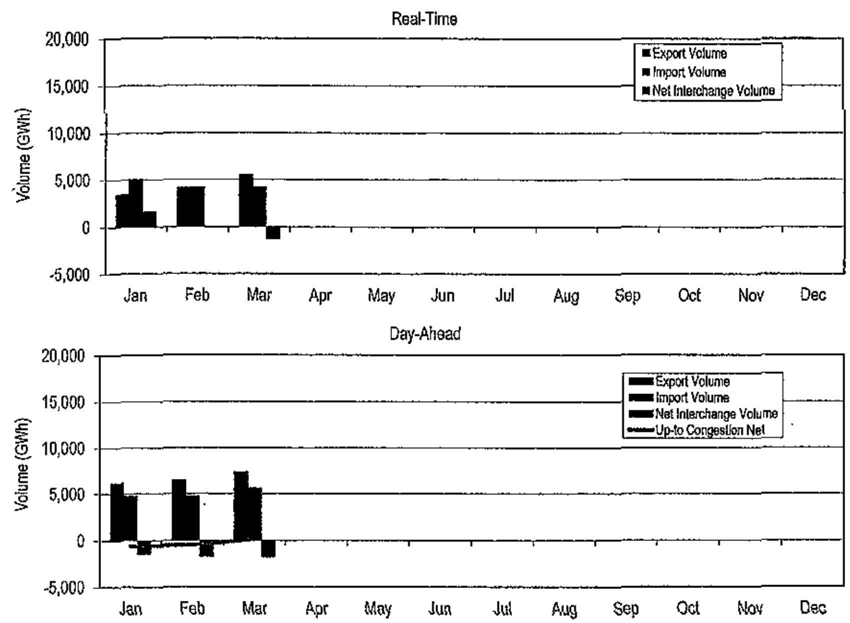
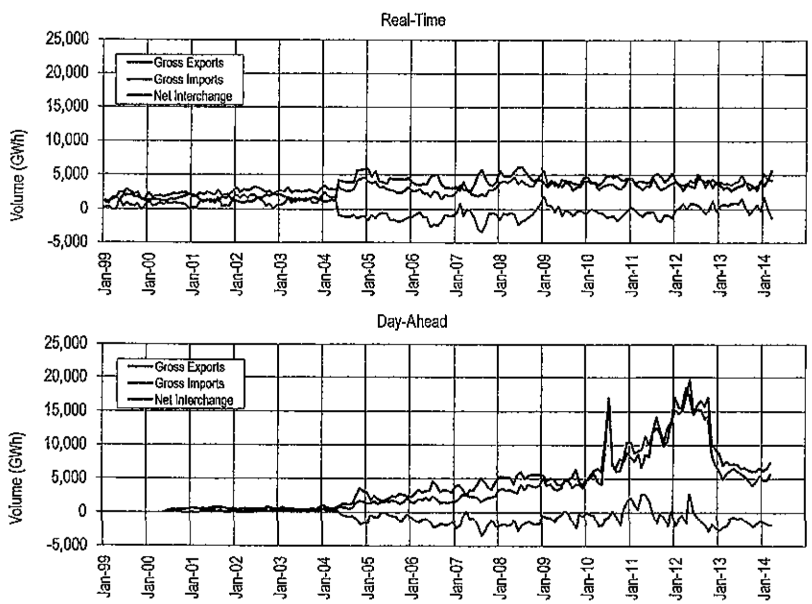


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through March, 2014. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Energy Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased.

While the gross import and export volumes in the Day-Ahead Energy Market have decreased, the net direction of power flows has remained predominantly in the export direction.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through March, 2014



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. See Table 9-16 for a list of active interfaces during the first three months of 2014. Figure 9-3 shows the approximate geographic location of the interfaces. In the first three months of 2014, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are nine separate interfaces that make up the MISO Interface between the PJM and MISO. Table 9-1 through Table 9-3 show the Real-Time Energy Market interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Energy Market is shown by interface for the first three months of 2014 in Table 9-1, while gross imports and exports are shown in Table 9-2 and Table 9-3.

In the Real-Time Energy Market, in the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 61.2 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30.7 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 15.5 percent, and PJM/Neptune (NEPT) with 15.0 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 55.2 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 76.4 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 37.3 percent, PJM/Tennessee Valley Authority (TVA) with 17.9 percent and PJM/Ameren-Illinois (AMIL) with 21.2 percent of the net import volume.[11]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by load serving entities or their affiliates within the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 70 percent of the generation output into the PJM footprint.[12] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

11 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).
12 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed April 16, 2014).

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through March, 2014

		Jan	Feb	Mar	Total
CPLE		(33.5)	(11.2)	(12.8)	(57.5)
CPLW		0.0	0.6	5.2	5.8
DUK		294.7	395.5	541.7	1,231.9
LGEE		262.4	230.3	159.5	652.2
MEC		(421.8)	(387.0)	(239.8)	(1,048.6)
MISO		1,193.0	(460.9)	(1,620.2)	(888.1)
	ALTE	(140.8)	(241.9)	(770.7)	(1,153.4)
	ALTW	(49.5)	(85.5)	(98.5)	(233.5)
	AMIL	917.6	478.4	317.9	1,713.9
	CIN	318.9	(341.6)	(350.1)	(372.7)
	CWLP	0.0	0.0	0.0	0.0
	IPL	87.3	(65.3)	(2.3)	19.6
	MECS	158.2	(25.4)	(564.6)	(431.9)
	NIPS	15.2	(51.6)	(3.7)	(40.1)
	WEC	(113.8)	(128.0)	(148.3)	(390.1)
NYISO		(1,091.2)	(1,328.3)	(1,701.2)	(4,120.8)
	HUDS	(79.2)	(210.2)	(98.9)	(388.3)
	LIND	(72.8)	(134.8)	(117.6)	(325.2)
	NEPT	(303.6)	(424.0)	(390.7)	(1,118.2)
	NYIS	(635.5)	(559.4)	(1,094.0)	(2,288.9)
OVEC		1,055.5	990.6	972.3	3,018.4
TVA		349.8	552.2	545.5	1,447.4
Total		1,608.8	(18.3)	(1,349.8)	240.8

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through March, 2014

		Jan	Feb	Mar	Total
CPLE		0.7	5.1	2.4	8.2
CPLW		0.0	0.6	5.2	5.8
DUK		355.0	427.5	563.5	1,346.0
LGEE		263.5	230.3	162.7	656.5
MEC		16.5	0.2	226.2	242.8
MISO		1,922.9	1,066.3	918.6	3,907.8
	ALTE	55.0	9.3	0.3	64.7
	ALTW	0.5	0.0	0.0	0.5
	AMIL	967.4	627.9	486.4	2,081.7
	CIN	517.5	160.6	176.7	854.7
	CWLP	0.0	0.0	0.0	0.0
	IPL	141.4	44.7	166.9	352.9
	MECS	215.2	219.9	85.1	520.2
	NIPS	25.9	3.9	0.9	30.6
	WEC	0.0	0.0	2.4	2.4
NYISO		1,022.4	838.9	773.7	2,635.0
	HUDS	0.0	0.0	0.0	0.0
	LIND	23.2	5.2	5.8	34.3
	NEPT	0.0	0.0	0.0	0.0
	NYIS	999.1	833.6	767.9	2,600.7
OVEC		1,082.6	1,016.0	995.4	3,094.0
TVA		413.4	559.8	549.5	1,522.7
Total		5,076.9	4,144.7	4,197.2	13,418.8

Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through March, 2014

		Jan	Feb	Mar	Total
CPLE		34.2	16.3	15.2	65.7
CPLW		0.0	0.0	0.0	0.0
DUK		60.3	32.0	21.8	114.1
LGEE		1.1	0.0	3.2	4.2
MEC		438.3	387.1	466.0	1,291.4
MISO		729.9	1,527.2	2,538.8	4,795.9
	ALTE	195.9	251.2	771.0	1,218.1
	ALTW	50.1	85.5	98.5	234.1
	AMIL	49.8	149.6	168.5	367.8
	CIN	198.6	502.1	526.7	1,227.4
	CWLP	0.0	0.0	0.0	0.0
	IPL	54.1	110.0	169.2	333.3
	MECS	57.1	245.3	649.7	952.1
	NIPS	10.7	55.5	4.6	70.7
	WEC	113.8	128.0	150.7	392.5
NYISO		2,113.6	2,167.2	2,475.0	6,755.7
	HUDS	79.2	210.2	98.9	388.3
	LIND	96.1	140.0	123.4	359.5
	NEPT	303.6	424.0	390.7	1,118.2
	NYIS	1,634.7	1,393.0	1,862.0	4,889.7
OVEC		27.1	25.5	23.0	75.6
TVA		63.6	7.6	4.0	75.2
Total		3,468.0	4,163.0	5,546.9	13,178.0

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[13] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[14]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[15] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. According to the *PJM Interface Price Definition Methodology*, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[16] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. Table 9-17 presents the interface pricing points used in the first three months of 2014.

13 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

14 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

15 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

16 See "PJM Interface Pricing Definition Methodology," (September 29, 2006) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx>.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified by PJM only occasionally.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[17]

In the Real-Time Energy Market, in the first three months of 2014, there were net scheduled exports at eleven of PJM's 18 interface pricing points eligible for real-time transactions.[18] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.1 percent of the total net exports: PJM/MISO with 57.6 percent, and PJM/NYIS with 20.4 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 39.5 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 84.4 percent of the total net imports: PJM/SouthIMP with 53.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 30.7 percent of the net import volume.[19]

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	(79.2)	(210.2)	(98.9)	(388.3)
IMO	390.9	171.2	227.6	789.7
LINDENVFT	(72.8)	(134.8)	(117.6)	(325.2)
MISO	(817.2)	(1,772.6)	(2,939.2)	(5,528.9)
NEPTUNE	(303.6)	(424.0)	(390.7)	(1,118.2)
NORTHWEST	(0.4)	(0.7)	(2.7)	(3.8)
NYIS	(548.6)	(414.6)	(997.0)	(1,960.2)
OVEC	1,055.5	990.6	972.3	3,018.4
SOUTHIMP	2,145.9	1,840.7	2,040.8	6,027.3
CPLEIMP	0.4	0.0	0.1	0.4
DUKIMP	101.2	216.8	106.6	424.6
NCMPAIMP	96.3	113.1	113.1	322.6
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,948.0	1,510.7	1,820.9	5,279.6
SOUTHEXP	(161.5)	(63.9)	(44.4)	(269.8)
CPLEEXP	(31.0)	(16.2)	(14.6)	(61.8)
DUKEXP	(32.3)	(22.3)	(14.9)	(69.5)
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	(2.7)	0.0	0.0	(2.7)
SOUTHWEST	(2.4)	(7.1)	0.0	(9.4)
SOUTHEXP	(93.2)	(18.4)	(14.9)	(126.4)
Total	1,608.8	(18.3)	(1,349.8)	240.8

17 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.
18 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).
19 In the Real-Time Energy Market, one PJM interface pricing point had a net interchange of zero (NCMPAEXP).

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	0.0	0.0	0.0	0.0
IMO	447.2	222.9	260.3	930.4
LINDENVFT	23.2	5.2	5.8	34.3
MISO	341.1	123.6	57.0	521.7
NEPTUNE	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0
NYIS	1,036.9	935.0	834.9	2,806.9
OVEC	1,082.6	1,016.0	995.4	3,094.0
SOUTHIMP	2,145.9	1,841.9	2,043.8	6,031.5
CPLEIMP	0.4	0.0	0.1	0.4
DUKIMP	101.2	216.8	106.6	424.6
NCMPAIMP	96.3	113.1	113.1	322.6
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,948.0	1,511.9	1,824.0	5,283.9
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	5,076.9	4,144.7	4,197.2	13,418.8

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	79.2	210.2	98.9	388.3
IMO	56.3	51.7	32.6	140.6
LINDENVFT	96.1	140.0	123.4	359.5
MISO	1,158.3	1,896.2	2,996.2	6,050.7
NEPTUNE	303.6	424.0	390.7	1,118.2
NORTHWEST	0.4	0.7	2.7	3.8
NYIS	1,585.5	1,349.7	1,832.0	4,767.1
OVEC	27.1	25.5	23.0	75.6
SOUTHIMP	0.0	1.2	3.0	4.2
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	1.2	3.0	4.2
SOUTHEXP	161.5	63.9	44.4	269.8
CPLEEXP	31.0	16.2	14.6	61.8
DUKEXP	32.3	22.3	14.9	69.5
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	2.7	0.0	0.0	2.7
SOUTHWEST	2.4	7.1	0.0	9.4
SOUTHEXP	93.2	18.4	14.9	126.4
Total	3,468.0	4,163.0	5,546.9	13,178.0

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[20] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow unless they are also

20 Effective September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[21]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 9-7, Table 9-8 and Table 9-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow.

Table 9-7 through Table 9-9 show the day-ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Energy Market is shown by interface for the first three months of 2014 in Table 9-7, while gross imports and exports are shown in Table 9-8 and Table 9-9.

In the Day-Ahead Energy Market in the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 67.3 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 33.6 percent, PJM/MidAmerican Energy Company (MEC) with 17.5 percent, and PJM/NEPT with 16.1 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 54.1 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 24.4 percent of the total net PJM exports in the Day-Ahead Energy Market. Six PJM interfaces had net scheduled imports, with two importing interfaces accounting for 89.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 71.7 percent, and PJM/DUK with 18.0 percent of the net import volume.[22]

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through March, 2014

	Jan	Feb	Mar	Total
CPLE	(30.1)	(15.5)	(13.9)	(59.5)
CPLW	0.0	0.6	0.0	0.6
DUK	151.9	128.5	270.6	551.0
LGEE	0.0	0.0	0.0	0.0
MEC	(433.6)	(375.5)	(438.5)	(1,247.6)
MISO	(137.8)	(528.3)	(1,069.7)	(1,735.8)
ALTE	(96.1)	(148.5)	(516.3)	(760.9)
ALTW	(7.3)	(18.8)	(13.8)	(39.9)
AMIL	25.4	81.2	27.2	133.8
CIN	(31.5)	(209.0)	(221.1)	(461.6)
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	87.1	87.1
MECS	75.0	(113.1)	(360.3)	(398.4)
NIPS	0.0	(45.2)	0.0	(45.2)
WEC	(103.4)	(74.9)	(72.5)	(250.7)
NYISO	(1,140.8)	(1,230.9)	(1,482.8)	(3,854.5)
HUDS	(45.7)	(141.5)	(77.2)	(264.3)
LIND	(10.2)	(22.3)	(15.8)	(48.4)
NEPT	(280.3)	(437.6)	(430.2)	(1,148.1)
NYIS	(804.6)	(629.4)	(959.6)	(2,393.6)
OVEC	727.2	728.3	733.3	2,188.8
TVA	8.8	29.3	55.2	93.3
Total without Up-To Congestion	(854.4)	(1,263.4)	(1,945.9)	(4,063.7)
Up-To Congestion	(578.5)	(482.9)	143.1	(918.3)
Total	(1,433.0)	(1,746.3)	(1,802.8)	(4,982.0)

21 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

22 In the Day-Ahead Energy Market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/LG&E Energy Transmission Services (LGEE)).

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through March, 2014

	Jan	Feb	Mar	Total
CPLE	0.0	0.0	0.0	0.0
CPLW	0.0	0.6	0.0	0.6
DUK	157.5	128.5	270.6	556.6
LGEE	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0
MISO	152.3	127.1	150.7	430.0
ALTE	1.1	0.0	0.0	1.1
ALTW	0.3	0.0	0.0	0.3
AMIL	25.4	88.7	45.4	159.5
CIN	26.1	0.0	0.0	26.1
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	87.1	87.1
MECS	99.4	38.4	15.9	153.7
NIPS	0.0	0.0	0.0	0.0
WEC	0.0	0.0	2.3	2.3
NYISO	679.5	611.9	610.9	1,902.3
HUDS	0.0	0.0	0.0	0.0
LIND	3.6	2.6	3.5	9.6
NEPT	0.0	0.0	0.0	0.0
NYIS	675.9	609.4	607.4	1,892.6
OVEC	727.3	728.3	733.3	2,188.9
TVA	29.7	29.3	55.2	114.1
Total without Up-To Congestion	1,746.2	1,625.7	1,820.7	5,192.6
Up-To Congestion	3,054.9	3,127.2	3,778.6	9,960.7
Total	4,801.1	4,752.9	5,599.2	15,153.3

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through March, 2014

	Jan	Feb	Mar	Total
CPLE	30.1	15.5	13.9	59.5
CPLW	0.0	0.0	0.0	0.0
DUK	5.6	0.0	0.0	5.6
LGEE	0.0	0.0	0.0	0.0
MEC	433.6	375.5	438.5	1,247.6
MISO	290.1	655.3	1,220.4	2,165.9
ALTE	97.2	148.5	516.3	761.9
ALTW	7.6	18.8	13.8	40.2
AMIL	0.0	7.5	18.3	25.7
CIN	57.6	209.0	221.1	487.7
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MECS	24.4	151.5	376.2	552.1
NIPS	0.0	45.2	0.0	45.2
WEC	103.4	74.9	74.8	253.0
NYISO	1,820.3	1,842.8	2,093.7	5,756.8
HUDS	45.7	141.5	77.2	264.3
LIND	13.8	24.9	19.3	58.0
NEPT	280.3	437.6	430.2	1,148.1
NYIS	1,480.5	1,238.8	1,567.0	4,286.2
OVEC	0.1	0.0	0.0	0.1
TVA	20.9	0.0	0.0	20.9
Total without Up-To Congestion	2,600.6	2,889.1	3,766.6	9,256.3
Up-To Congestion	3,633.4	3,610.2	3,635.5	10,879.0
Total	6,234.0	6,499.3	7,402.0	20,135.3

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Energy Market interchange totals at the individual interface pricing points. In the first three months of 2014, up-to congestion transactions accounted for 65.7 percent of all scheduled import MW transactions, 54.0 percent of all scheduled export MW transactions and 18.4 percent of the net interchange volume in the Day-Ahead Energy Market. Net interchange in the Day-Ahead Energy Market, including up-to congestion transactions, is shown by interface pricing point in the first three months of 2014 in Table 9-10. Up-to congestion transactions by interface pricing point in the first three months of 2014 are shown in Table

9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Energy Market are shown in Table 9-12 and Table 9-14, while gross import up-to congestion transactions are show in Table 9-13 and gross export up-to congestion transactions are shown in Table 9-15.

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created at the NIPSCO Interface prior to the integration.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The Southeast pricing point also remains eligible to receive the real-time interface price only through the reserve sharing agreement with VACAR. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.

In the Day-Ahead Energy Market, in the first three months of 2014, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 61.9 percent of the total net exports: PJM/SouthEXP with 21.0 percent, PJM/NYIS with 21.0 percent and PJM/MISO with 19.9 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 33.8 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interface pricing points had net imports, with three importing interface pricing points accounting for 76.3 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 35.1 percent, PJM/SouthIMP with 22.4 percent, and PJM/Southeast with 18.8 percent of the net import volume.[23]

In the Day-Ahead Energy Market, in the first three months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 91.5 percent of the total net up-to congestion exports: PJM/SouthEXP with 41.8 percent, PJM/Southwest with 29.2 percent, and PJM/NIPSCO with 20.5 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 2.5 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/Linden with 1.8 percent and PJM/NEPTUNE with 0.7 percent). The PJM/NYIS, and PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Seven PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 78.9 percent of the total net up-to congestion imports: PJM/Northwest with 34.8 percent,

23 In the Day-Ahead Energy Market, one PJM interface pricing point had a net interchange of zero (PJM/DUKEXP).

PJM/Southeast with 25.5 percent, and PJM/Ontario Independent Electricity System Operator (IMO) with 18.6 percent of the net import volume.[24]

Table 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	(19.6)	(8.6)	68.1	39.8
IMO	319.5	296.7	271.0	887.2
LINDENVFT	(72.0)	(69.4)	(0.6)	(141.9)
MISO	(442.9)	(648.2)	(977.1)	(2,068.2)
NEPTUNE	(353.8)	(396.7)	(433.3)	(1,183.8)
NIPSCO	(763.3)	(19.3)	(274.5)	(1,057.1)
NORTHWEST	24.1	134.8	(36.0)	123.0
NYIS	(755.3)	(510.8)	(912.7)	(2,178.9)
OVEC	1,225.6	54.0	599.1	1,878.6
SOUTHIMP	641.1	834.2	1,639.1	3,114.4
CPLEIMP	0.0	0.6	0.0	0.6
DUKIMP	29.3	64.1	17.8	111.2
NCMPAIMP	67.9	31.7	51.3	151.0
SOUTHEAST	216.3	238.1	718.8	1,173.2
SOUTHWEST	161.0	156.2	164.8	482.0
SOUTHIMP	166.5	343.6	686.3	1,196.4
SOUTHEXP	(1,236.4)	(1,412.9)	(1,745.9)	(4,395.2)
CPLEEXP	(28.4)	(14.5)	(13.1)	(55.9)
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	(1.7)	(0.9)	(0.8)	(3.5)
SOUTHEAST	(59.9)	(83.4)	(26.0)	(169.2)
SOUTHWEST	(507.8)	(648.2)	(831.2)	(1,987.2)
SOUTHEXP	(638.6)	(665.8)	(874.8)	(2,179.3)
Total	(1,433.0)	(1,746.3)	(1,802.8)	(4,982.0)

Table 9-11 Up-to congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	26.1	123.2	145.2	294.6
IMO	218.6	259.9	255.7	734.1
LINDENVFT	(61.7)	(47.1)	15.3	(93.5)
MISO	(195.6)	5.7	243.1	53.2
NEPTUNE	(73.5)	41.0	(3.1)	(35.7)
NIPSCO	(763.3)	(19.3)	(274.5)	(1,057.1)
NORTHWEST	457.7	510.3	402.6	1,370.6
NYIS	49.3	128.0	42.5	219.8
OVEC	498.4	(674.3)	(130.4)	(306.4)
SOUTHIMP	445.3	587.1	1,178.8	2,211.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	216.3	238.1	718.8	1,173.2
SOUTHWEST	161.0	156.2	164.8	482.0
SOUTHIMP	68.0	192.9	295.2	556.1
SOUTHEXP	(1,179.8)	(1,397.4)	(1,732.0)	(4,309.2)
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	(59.9)	(83.4)	(26.0)	(169.2)
SOUTHWEST	(507.8)	(648.2)	(831.2)	(1,987.2)
SOUTHEXP	(612.2)	(665.8)	(874.8)	(2,152.8)
Total Interfaces	(578.5)	(482.9)	143.1	(918.3)
INTERNAL	35,413.4	36,715.9	41,839.2	113,968.6
Total	34,834.9	36,109.8	41,837.1	112,755.6

24 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	187.4	317.0	257.6	761.9
IMO	358.4	375.9	340.3	1,074.7
LINDENVFT	84.4	70.4	100.5	255.3
MISO	334.1	318.3	445.6	1,097.9
NEPTUNE	38.4	133.4	156.1	327.9
NIPSCO	85.5	172.9	80.0	338.3
NORTHWEST	614.8	605.4	503.2	1,723.4
NYIS	810.5	787.0	726.5	2,323.9
OVEC	1,646.5	1,138.6	1,350.5	4,135.6
SOUTHIMP	641.1	834.2	1,639.1	3,114.4
CPLEIMP	0.0	0.6	0.0	0.6
DUKIMP	29.3	64.1	17.8	111.2
NCMPAIMP	67.9	31.7	51.3	151.0
SOUTHEAST	216.3	238.1	718.8	1,173.2
SOUTHWEST	161.0	156.2	164.8	482.0
SOUTHIMP	166.5	343.6	686.3	1,196.4
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	4,801.1	4,752.9	5,599.2	15,153.3

Table 9-13 Up-to congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	187.4	317.0	257.6	761.9
IMO	257.5	337.5	324.4	919.5
LINDENVFT	80.8	67.8	97.0	245.6
MISO	291.2	318.3	445.3	1,054.8
NEPTUNE	38.4	133.4	156.1	327.9
NIPSCO	85.5	172.9	80.0	338.3
NORTHWEST	614.8	605.4	503.2	1,723.4
NYIS	134.6	177.6	115.2	427.4
OVEC	919.3	410.3	621.0	1,950.6
SOUTHIMP	445.3	587.1	1,178.8	2,211.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	216.3	238.1	718.8	1,173.2
SOUTHWEST	161.0	156.2	164.8	482.0
SOUTHIMP	68.0	192.9	295.2	556.1
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	3,054.9	3,127.2	3,778.6	9,960.7

Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	206.9	325.6	189.5	722.1
IMO	39.0	79.2	69.2	187.5
LINDENVFT	156.4	139.8	101.1	397.2
MISO	776.9	966.5	1,422.6	3,166.1
NEPTUNE	392.2	530.0	589.5	1,511.7
NIPSCO	848.8	192.2	354.4	1,395.4
NORTHWEST	590.7	470.6	539.1	1,600.4
NYIS	1,565.8	1,297.8	1,639.2	4,502.8
OVEC	421.0	1,084.6	751.4	2,257.0
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	1,236.4	1,412.9	1,745.9	4,395.2
CPLEEXP	28.4	14.5	13.1	55.9
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	1.7	0.9	0.8	3.5
SOUTHEAST	59.9	83.4	26.0	169.2
SOUTHWEST	507.8	648.2	831.2	1,987.2
SOUTHEXP	638.6	665.8	874.8	2,179.3
Total	6,234.0	6,499.3	7,402.0	20,135.3

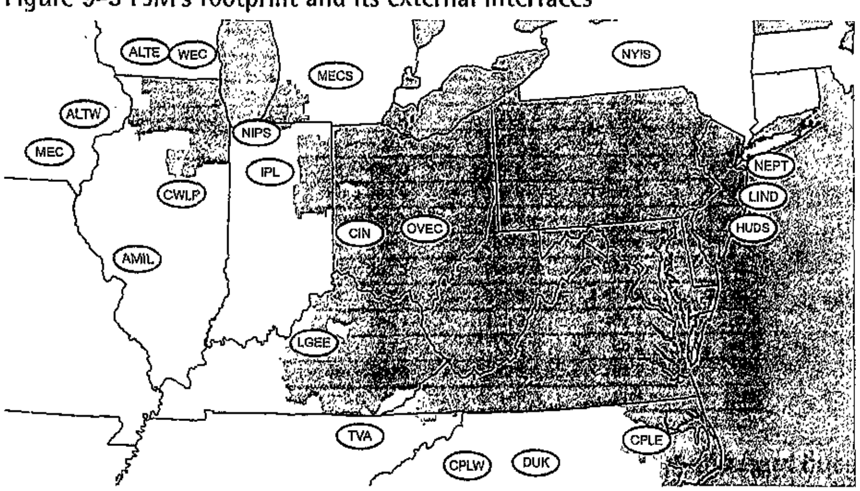
Table 9-15 Up-to congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2014

	Jan	Feb	Mar	Total
HUDS	161.2	193.7	112.4	467.4
IMO	39.0	77.6	68.7	185.3
LINDENVFT	142.6	114.9	81.7	339.2
MISO	486.8	312.6	202.2	1,001.6
NEPTUNE	111.9	92.4	159.3	363.6
NIPSCO	848.8	192.2	354.4	1,395.4
NORTHWEST	157.1	95.1	100.6	352.8
NYIS	85.3	49.6	72.8	207.6
OVEC	420.9	1,084.6	751.4	2,256.9
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	1,179.8	1,397.4	1,732.0	4,309.2
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	59.9	83.4	26.0	169.2
SOUTHWEST	507.8	648.2	831.2	1,987.2
SOUTHEXP	612.2	665.8	874.8	2,152.8
Total	3,633.4	3,610.2	3,635.5	10,879.0

Table 9-16 Active interfaces: January through March, 2014[25]

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
HUDS	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
OVEC	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 9-3 PJM's footprint and its external interfaces



25 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

Table 9-17 Active pricing points: January through March, 2014

	Jan	Feb	Mar
CPLEEXP	Active	Active	Active
CPLEIMP	Active	Active	Active
DUKEXP	Active	Active	Active
DUKIMP	Active	Active	Active
HUDS	Active	Active	Active
LIND	Active	Active	Active
MISO	Active	Active	Active
NCMPAEXP	Active	Active	Active
NCMPAIMP	Active	Active	Active
NEPT	Active	Active	Active
NIPSCO	Active	Active	Active
Northwest	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
OVEC	Active	Active	Active
Southeast	Active	Active	Active
SOUTHEXP	Active	Active	Active
SOUTHIMP	Active	Active	Active
Southwest	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[26]

26 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market based price differentials that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs.

PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both MISO's border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows). In the first three months of 2014, there were net scheduled flows of 2,251 GWh through MISO that received an interface pricing point associated with the southern border. Conversely, in the first three months of 2014, there were no net scheduled flows across the southern border that received the MISO interface pricing point.

In the first three months of 2014, net scheduled interchange was -362 GWh and net actual interchange was -243 GWh, a difference of 119 GWh. In the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh.[27] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[28]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through March, 2014

	Actual	Net Scheduled	Difference (GWh)
CPLE	2,514	(64)	2,578
CPLW	(326)	6	(332)
DUK	347	1,232	(885)
LGEE	888	652	235
MEC	(452)	(1,046)	594
MISO	(4,706)	(996)	(3,710)
ALTE	(1,848)	(1,153)	(695)
ALTW	(563)	(234)	(330)
AMIL	3,111	1,714	1,397
CIN	(1,685)	(429)	(1,256)
CWLP	(150)	0	(150)
IPL	183	(31)	214
MECS	(3,889)	(432)	(3,457)
NIPS	(917)	(40)	(877)
WEC	1,052	(390)	1,442
NYISO	(4,082)	(4,174)	92
HUDS	(388)	(388)	0
LIND	(325)	(325)	0
NEPT	(1,118)	(1,118)	0
NYIS	(2,250)	(2,342)	92
OVEC	4,058	3,018	1,040
TVA	1,516	1,010	506
Total	(243)	(362)	119

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive

27 The "Net Scheduled" values shown in Table 9-18 include dynamic schedules. Dynamic schedules are commonly used for scheduling generation from one another balancing authority area to another. As defined by NERC, a dynamic schedule is a telemetered reading or value from such a generating unit that is updated in real time and used as a schedule in the AGC/ACE equation of the BA to which it is scheduled. The hourly integrated values of dynamic schedules are treated as a schedule for interchange accounting purposes. Table 9-1 through Table 9-6 represent block scheduled transactions, submitted through the Enhanced Energy Scheduling (EES) application and tagged through the NERC e-tag process only. As a result, the net interchange in Table 9-18 does not match the interchange values shown in Table 9-1 through Table 9-6.

28 See PJM. "M-12: Balancing Operations," Revision 30 (December 1, 2013).

the specific interface price.[29] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-19 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (4,939 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 5,313 GWh).

The IMO Interface Pricing Point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

29 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model," <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008.)

Table 9-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through March, 2014

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(388)	(388)	(0)
IMO	0	790	(790)
LINDENVFT	(325)	(325)	0
MISO	(4,706)	(5,636)	930
NEPTUNE	(1,118)	(1,118)	0
NORTHWEST	(452)	(2)	(450)
NYIS	(2,250)	(2,013)	(237)
OVEC	4,058	3,018	1,040
SOUTHIMP	4,939	5,583	(644)
CPLEIMP	0	0	(0)
DUKIMP	0	425	(425)
NCMPAIMP	0	323	(323)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	4,939	4,835	104
SOUTHEXP	0	(270)	270
CPLEEXP	0	(62)	62
DUKEXP	0	(69)	69
NCMPAEXP	0	0	0
SOUTHEAST	0	(3)	3
SOUTHWEST	0	(9)	9
SOUTHEXP	0	(126)	126
Total	(243)	(362)	119

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2014

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(388)	(388)	0
LINDENVFT	(325)	(325)	0
MISO	(4,706)	(4,724)	18
NEPTUNE	(1,118)	(1,118)	0
NORTHWEST	(452)	(2)	(450)
NYIS	(2,250)	(2,136)	(115)
OVEC	4,058	3,018	1,040
SOUTHIMP	4,939	5,583	(644)
CPLEIMP	0	0	0
DUKIMP	0	425	(425)
NCMPAIMP	0	323	(323)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	4,939	4,835	104
SOUTHEXP	0	(270)	270
CPLEEXP	0	(62)	62
DUKEXP	0	(69)	69
NCMPAEXP	0	0	0
SOUTHEAST	0	(3)	3
SOUTHWEST	0	(9)	9
SOUTHEXP	0	(126)	126
Total	(243)	(362)	119

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loops flows would be reduced.

The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.

Table 9-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the Interface Pricing Points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 9-21 shows that in the first three months of 2014, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SouthIMP interface, and thus actual flows were assigned the SouthIMP Interface Pricing point (312 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO Interface, and thus were assigned the MISO Interface Pricing point (1,209 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through March, 2014

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(1,848)	(1,153)	(695)	IPL		183	(31)	214
	MISO	(1,848)	(1,165)	(683)		IMO	0	242	(242)
	SOUTHIMP	0	12	(12)		MISO	183	(362)	545
ALTW		(563)	(234)	(330)		SOUTHIMP	0	89	(89)
	MISO	(563)	(234)	(330)	LGEE		888	652	235
AMIL		3,111	1,714	1,397		SOUTHEXP	0	(4)	4
	MISO	3,111	(26)	3,137		SOUTHIMP	888	656	231
	SOUTHIMP	0	1,750	(1,750)	LIND		(325)	(325)	0
	SOUTHWEST	0	(9)	9		LINDENVFT	(325)	(325)	0
CIN		(1,685)	(429)	(1,256)	MEC		(452)	(1,046)	594
	IMO	0	266	(266)		MISO	0	(1,275)	1,275
	MISO	(1,685)	(1,209)	(476)		NORTHWEST	(452)	2	(454)
	NORTHWEST	0	(3)	3		SOUTHIMP	0	226	(226)
	NYIS	0	206	(206)	MECS		(3,889)	(432)	(3,457)
	SOUTHEXP	0	(1)	1		IMO	0	405	(405)
	SOUTHIMP	0	312	(312)		MISO	(3,889)	(933)	(2,955)
CPLE		2,514	(64)	2,578		NORTHWEST	0	(1)	1
	CPLEEXP	0	(62)	62		SOUTHIMP	0	98	(98)
	DUKIMP	0	7	(7)	NEPT		(1,118)	(1,118)	0
	SOUTHEXP	0	(1)	1		NEPTUNE	(1,118)	(1,118)	0
	SOUTHIMP	2,514	(5)	2,520	NIPS		(917)	(40)	(877)
	SOUTHEAST	0	(3)	3		MISO	(917)	(40)	(877)
CPLW		(326)	6	(332)	NYIS		(2,250)	(2,342)	92
	SOUTHIMP	(326)	6	(332)		IMO	0	(123)	123
CWLP		(150)	0	(150)		NYIS	(2,250)	(2,219)	(31)
	MISO	(150)	0	(150)	OVEC		4,058	3,018	1,040
DUK		347	1,232	(885)		OVEC	4,058	3,018	1,040
	DUKEXP	0	(69)	69	TVA		1,516	1,010	506
	DUKIMP	0	418	(418)		SOUTHEXP	0	(75)	75
	NCMPAIMP	0	323	(323)		SOUTHIMP	1,516	1,085	431
	SOUTHEXP	0	(45)	45	WEC		1,052	(390)	1,442
	SOUTHIMP	347	605	(259)		MISO	1,052	(392)	1,444
HUDS		(388)	(388)	0		SOUTHIMP	0	2	(2)
	HUDSONTP	(388)	(388)	0	Grand Total		(243)	(362)	119

Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-22 shows that in the first three months of 2014, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO Interface Pricing Point, had market paths that entered the PJM Energy Market at the MECS Interface (405 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO Interface Pricing Point, had market paths that exited the PJM Energy Market at the NYIS Interface (123 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through March, 2014

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(62)	62
	CPLE	0	(62)	62
CPLEIMP		0	0	(0)
	CPLE	0	0	(0)
DUKEXP		0	(69)	69
	DUK	0	(69)	69
DUKIMP		0	425	(425)
	CPLE	0	7	(7)
	DUK	0	418	(418)
HUDSONTP		(388)	(388)	0
	HUDS	(388)	(388)	0
IMO		0	790	(790)
	CIN	0	266	(266)
	IPL	0	242	(242)
	MECS	0	405	(405)
	NYIS	0	(123)	123
LINDENVFT		(325)	(325)	0
	LIND	(325)	(325)	0
MISO		(4,706)	(5,636)	930
	ALTE	(1,848)	(1,165)	(683)
	ALTW	(563)	(234)	(330)
	AMIL	3,111	(26)	3,137
	CIN	(1,685)	(1,209)	(476)
	CWLP	(150)	0	(150)
	IPL	183	(362)	545
	MEC	0	(1,275)	1,275
	MECS	(3,889)	(933)	(2,955)
	NIPS	(917)	(40)	(877)
	WEC	1,052	(392)	1,444
NCMPAIMP		0	323	(323)
	DUK	0	323	(323)
NEPTUNE		(1,118)	(1,118)	0
	NEPT	(1,118)	(1,118)	0
NORTHWEST		(452)	(2)	(450)
	CIN	0	(3)	3
	MEC	(452)	2	(454)
	MECS	0	(1)	1
NYIS		(2,250)	(2,013)	(237)
	CIN	0	206	(206)
	NYIS	(2,250)	(2,219)	(31)
OVEC		4,058	3,018	1,040
	OVEC	4,058	3,018	1,040
SOUTHEAST		0	(3)	3
	CPLE	0	(3)	3
SOUTHEXP		0	(126)	126
	CIN	0	(1)	1
	CPLE	0	(1)	1
	DUK	0	(45)	45
	LGEE	0	(4)	4
	TVA	0	(75)	75
	WEC	0	(0)	0
SOUTHIMP		4,939	4,835	104
	ALTE	0	12	(12)
	AMIL	0	1,750	(1,750)
	CIN	0	312	(312)
	CPLE	2,514	(5)	2,520
	CPLW	(326)	6	(332)
	DUK	347	605	(259)
	IPL	0	89	(89)
	LGEE	888	656	231
	MEC	0	226	(226)
	MECS	0	98	(98)
	TVA	1,516	1,085	431
	WEC	0	2	(2)
SOUTHWEST		0	(9)	9
	AMIL	0	(9)	9
Grand Total		(243)	(362)	119

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange transactions then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[30,31]

In 2013, questions were raised in the PJM/MISO Joint and Common Market (JCM) Initiative meetings whether the existing interface definitions utilized by PJM and MISO were accurately reflecting the value of congestion applied to interchange transactions when a M2M constraint is binding in either footprint.

When a M2M constraint binds, PJM's LMP calculations at the nine selected buses that make up PJM's MISO interface pricing point is determined based on the PJM model's distribution factors

30 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed April 17, 2014). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

31 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (Accessed April 17, 2014).

of those selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint.

PJM's MISO interface pricing point is a weighted aggregate price of the selected bus LMPs. Because PJM's MISO interface pricing point is calculated based on buses located within the MISO footprint (and in particular to the west of all M2M flowgates), PJM's calculated LMP at those buses may include a congestion component of the M2M flowgates located inside the MISO footprint.

MISO's calculated LMPs at those same buses also include the congestion component as determined based on the MISO model's distribution factors and the calculated MISO shadow price of the same binding M2M constraint. The MISO's PJM interface pricing point is a weighted aggregate price of the selected buses' LMPs. MISO's PJM interface pricing point includes all PJM generator buses located within the PJM footprint.

The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. By modifying interface price definitions in this manner, the congestion components of the bus LMPs that make up the interface prices in the individual RTOs would accurately reflect the value of congestion on M2M constraints to either RTO and therefore facilitate convergence through efficient price signals.

PJM is planning to modify the definition of the PJM/MISO interface.[32] The new interface definition will include ten equally weighted buses that are close to the PJM/MISO border. PJM's analysis of hourly flows on all of the ties between PJM and MISO showed that over 80 percent of the tie line flows were represented by the same ten ties composed of MISO and PJM monitored facilities. PJM selected generator buses electrically close to those ten tie lines. A PJM generator bus was selected for MISO monitored tie lines, and a MISO generator bus was selected for PJM monitored tie lines.

32 See "MISO Interface Definition Changes," PJM Presentation to the Markets Implementation Committee (February 5, 2014) <http://www.pjm.com/~/media/committees-groups/committees/mic/20140205/20140207-item-11a-miso-interface-definition.ashx> (February 5, 2014).

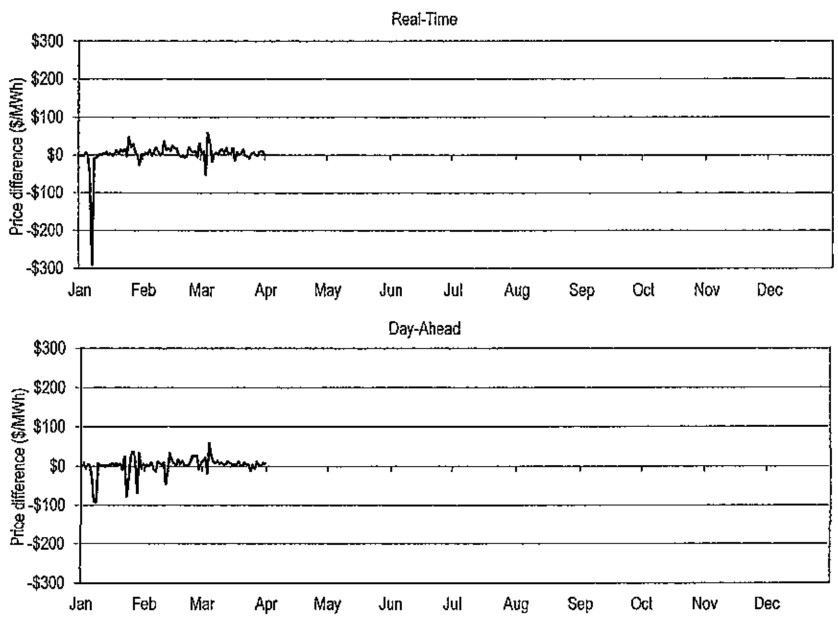
Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first three months of 2014, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first three months of 2014, the PJM average hourly locational marginal price (LMP) at the PJM/MISO border was $50.83 while the MISO LMP at the border was $51.20, a difference of $0.38. While the average hourly LMP difference at the PJM/MISO border was only $0.38, the average of the absolute values of the hourly differences was $25.58. The average hourly flow in the first three months of 2014 was -2,179 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) The direction of flow was consistent with price differentials in only 48.9 percent of hours in the first three months of 2014. When the MISO/PJM interface price was greater than the PJM/MISO interface price, the average difference was $26.16. When the PJM/MISO interface price was greater than the MISO/PJM interface price, the average difference was $25.01. In the first three months of 2014, when the MISO/PJM interface price was greater than the PJM/MISO interface price, and when the power flows were from PJM to MISO, the average price difference was $23.35. When the MISO/PJM interface price was greater than the PJM/MISO interface price, and when the power flows were from MISO to PJM, the average price difference was $47.64. When the PJM/MISO interface price was greater than the MISO/PJM interface price, and when power flows were from MISO to PJM, the average price difference was $119.47. When the PJM/MISO interface price was greater than the MISO/PJM interface price, and when power flows were from PJM to MISO, the average price difference was $14.60.

In the first three months of 2014, the day-ahead PJM average hourly LMP at the PJM/MISO border was $56.83 while the MISO LMP at the border was $58.86, a difference of $2.03 per MWh.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through March, 2014



Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

In the first three months of 2014, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,055 hours (48.9 percent of all hours), and was inconsistent with price differentials in 1,104 hours (51.1 percent of all hours). Table 9-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 1,104 hours where flows were uneconomic, 1,024 of those hours (92.8 percent) had a price difference greater than or equal to $1.00 and 643 of all uneconomic hours (58.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $592.36. Of the 1,055 hours where flows were economic, 978 of those hours (92.7 percent) had a price difference greater than or equal to $1.00 and 740 of all economic hours (70.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $1,576.11.

Table 9-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through March, 2014

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	1,104	100.0%	1,055	100.0%
$1.00	1,024	92.8%	978	92.7%
$5.00	643	58.2%	740	70.1%
$10.00	406	36.8%	581	55.1%
$15.00	306	27.7%	465	44.1%
$20.00	233	21.1%	394	37.3%
$25.00	189	17.1%	324	30.7%
$50.00	86	7.8%	160	15.2%
$75.00	48	4.3%	92	8.7%
$100.00	30	2.7%	49	4.6%
$200.00	12	1.1%	18	1.7%
$300.00	3	0.3%	13	1.2%
$400.00	3	0.3%	8	0.8%
$500.00	2	0.2%	8	0.8%
$1,000.00	0	0.0%	4	0.4%
$1,500.00	0	0.0%	2	0.2%
$2,000.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface *prices and inter-RTO/ISO power flows, and those price differentials.*[33]

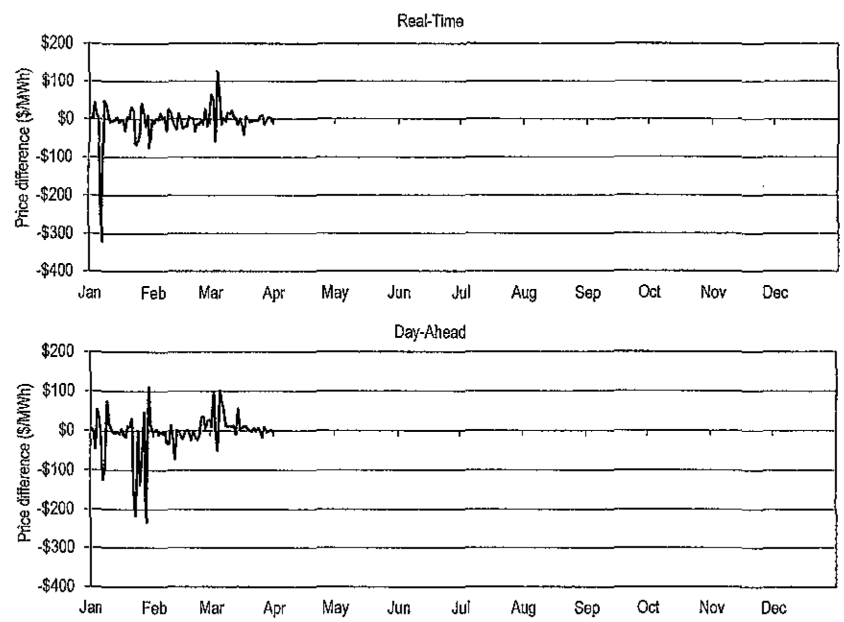
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first three months of 2014, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first three months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first three months of 2014, the PJM average hourly LMP at the PJM/NYISO border was $100.51 while the NYISO LMP at the border was $97.37, a difference of $3.15. While the average hourly LMP difference at the PJM/NYISO border was only $3.15, the average of the absolute value of the hourly difference was $44.74. The average hourly flow in the first three months of 2014 was -1,042 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flow was consistent with price differentials in 57.8 percent of the hours in the first three months of 2014. In the first three months of 2014, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS interface price, the average difference was $37.70. When the PJM/NYIS interface price was greater than the NYIS/PJM proxy bus price, the average difference was $53.40. In the first three months of 2014, when the NYISO/PJM interface price was greater than the PJM/NYISO interface price, and when the power flows were from PJM to NYISO, the average price difference was $35.57. When the NYISO/PJM interface price was greater than the PJM/NYISO interface price, and when the power flows were from NYISO to PJM, the average price difference was $71.78. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $129.75. When the PJM/NYISO interface price was greater than the NYISO/PJM interface price, and when power flows were from PJM to NYISO, the average price difference was $41.97.

In the first three months of 2014, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $110.55 while the NYIS LMP at the border was $106.28, a difference of $4.27.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March, 2014



33 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

In the first three months of 2014, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,247 (57.8 percent of all hours), and was inconsistent with price differences in 912 hours (42.2 percent of all hours). Table 9-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 912 hours where flows were uneconomic, 872 of those hours (95.6 percent) had a price difference greater than or equal to $1.00 and 735 of all uneconomic hours (80.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $577.83. Of the 1,247 hours where flows were economic, 1,204 of those hours (96.6 percent) had a price difference greater than or equal to $1.00 and 1,005 of all economic hours (80.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $1,311.87.

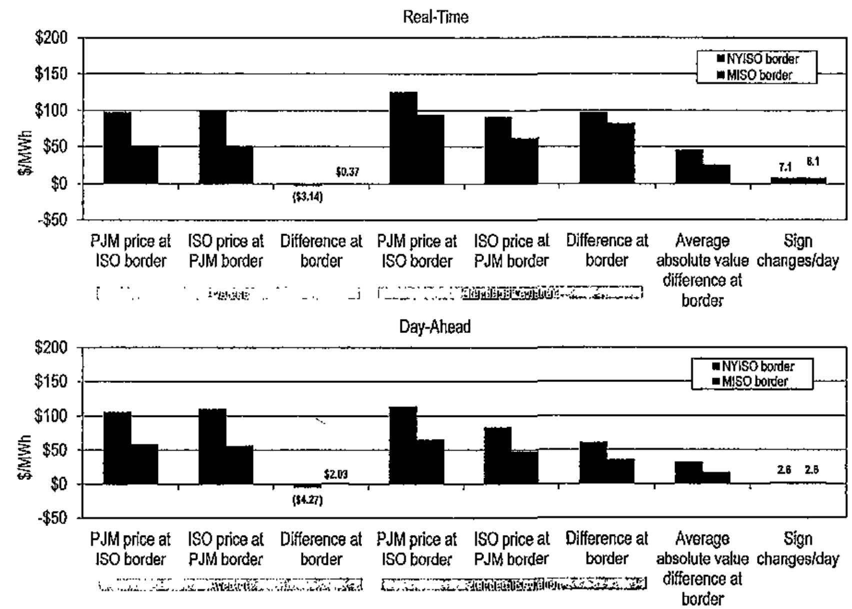
Table 9-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through March, 2014

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	912	100.0%	1,247	100.0%
$1.00	872	95.6%	1,204	96.6%
$5.00	735	80.6%	1,005	80.6%
$10.00	594	65.1%	821	65.8%
$15.00	513	56.3%	682	54.7%
$20.00	435	47.7%	595	47.7%
$25.00	399	43.8%	531	42.6%
$50.00	235	25.8%	307	24.6%
$75.00	159	17.4%	203	16.3%
$100.00	105	11.5%	123	9.9%
$200.00	36	3.9%	43	3.4%
$300.00	15	1.6%	17	1.4%
$400.00	6	0.7%	10	0.8%
$500.00	2	0.2%	8	0.6%
$1,000.00	0	0.0%	4	0.3%
$1,500.00	0	0.0%	0	0.0%
$2,000.00	0	0.0%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 9-6, including average prices and measures of variability.

Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through March, 2014



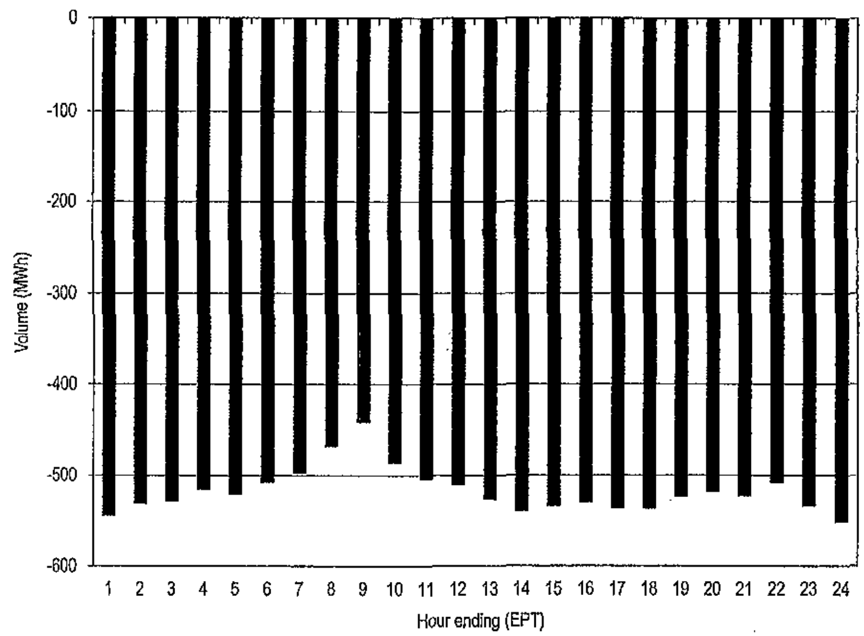
Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first three months of 2014, the PJM average hourly LMP at the Neptune Interface was $104.25 while the NYISO LMP at the Neptune Bus was $128.10, a difference of $23.85.[34] While the average hourly LMP difference at the PJM/Neptune border was $23.85, the average of the absolute value of the hourly difference was $70.23. The average hourly flow during the first three months of 2014 was -518 MW.[35] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 71.4 percent of the hours in the first three months of 2014. When the NYISO/Neptune bus price was greater than the PJM/NEPT interface price, the average hourly price difference was $62.74. When the PJM/NEPT interface price was greater than the NYISO/Neptune bus interface price, the average price difference was $81.89.

34 In the first three months of 2014, there were 198 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $102.11 while the NYISO LMP at the Neptune Bus during non-zero flows was $123.52, a difference of $21.41.

35 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -570 MW.

Figure 9-7 Neptune hourly average flow: January through March, 2014



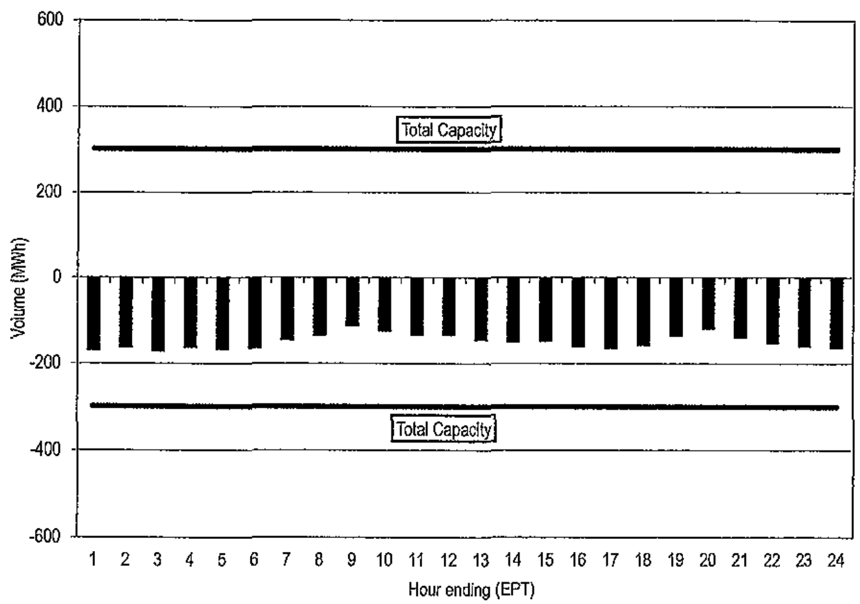
Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first three months of 2014, the PJM average hourly LMP at the Linden Interface was $105.90 while the NYISO LMP at the Linden Bus was $110.97, a difference of $5.08.[36] While the average hourly LMP difference at the PJM/Linden border was $5.08, the average of the absolute value of the hourly difference was $58.36. The average

36 In the first three months of 2014, there were 128 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $102.27 while the NYISO LMP at the Neptune Bus during non-zero flows was $109.82, a difference of $7.55.

hourly flow in the first three months of 2014 was -151 MW.[37] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 65.4 percent of the hours in the first three months of 2014. When the NYISO/Linden bus price was greater than the PJM/LIND interface price, the average hourly price difference was $49.20. When the PJM/LIND interface price was greater than the NYISO/Linden bus price, the average price difference was $71.29.

Figure 9-8 Linden hourly average flow: January through March, 2014[38]

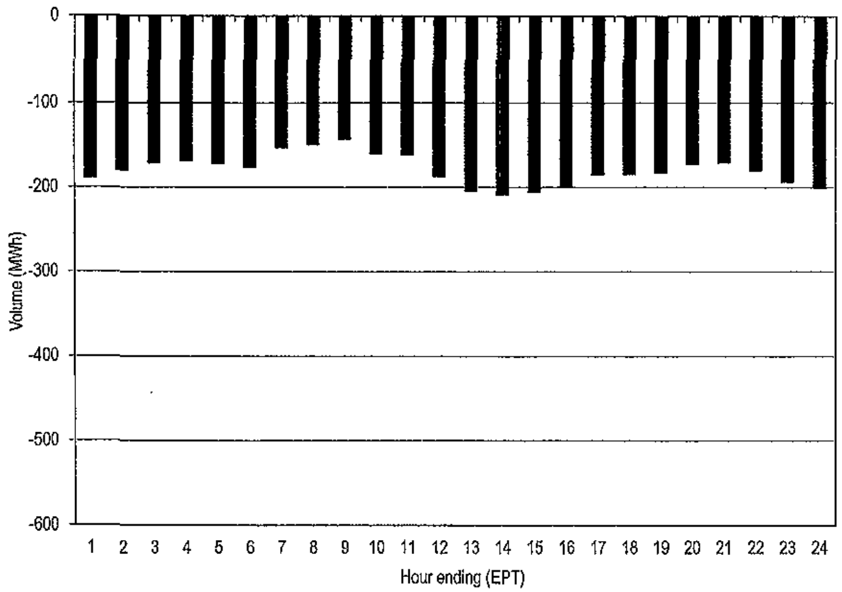


Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). In the first three months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus. The PJM average hourly LMP at the Hudson Interface was $124.61 while the NYISO LMP at the Hudson Bus was $123.22, a difference of $1.39.[39] While the average hourly LMP difference at the PJM/Hudson border was $1.39, the average of the absolute value of the hourly difference was $64.76. The average hourly flow during the first three months of 2014 was -180 MW.[40] (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) The flows were consistent with price differentials in 62.9 percent of the hours in the first three months of 2014. When the NYISO/Hudson bus price was greater than the PJM/HUDS interface price, the average hourly price difference was $62.04. When the PJM/HUDS interface price was greater than the NYISO/Hudson bus price, the average price difference was $87.58.

37 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Linden VFT line was -160 MW.
38 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.
39 In the first three months of 2014, there were 841 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $131.57 while the NYISO LMP at the Hudson Bus during non-zero flows was $138.09, a difference of $6.52.
40 The average hourly flow during the first three months of 2014, ignoring hours with no flow, on the Hudson line was -295 MW.

Figure 9-9 Hudson hourly average flow: January through March, 2014



Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include an implemented operating agreement with MISO and the NYISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

PJM and MISO Joint Operating Agreement[41]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[42]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.[43]

Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of January 1, 2014, PJM had 159 flowgates eligible for M2M (Market to Market) coordination. Between January 1, 2014 and March 31, 2014, PJM added 12 and deleted 10 flowgates, leaving 161 flowgates eligible for M2M coordination as of March 31, 2014. As of January 1, 2014, MISO had 265 flowgates eligible for M2M coordination. Between January 1, 2014 and March 31, 2014, MISO added 33 and deleted 27 flowgates, leaving 271 flowgates eligible for M2M coordination as of March 31, 2014. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

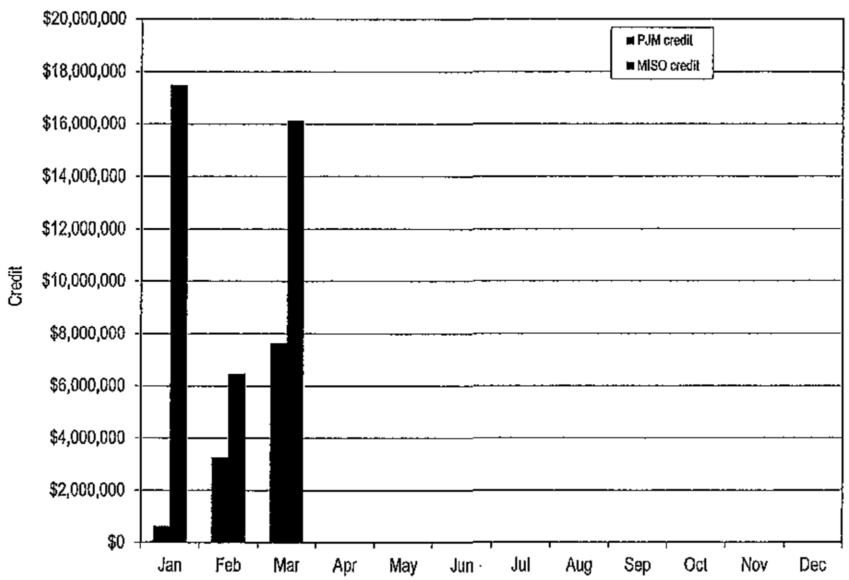
41 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed April 17, 2014).

42 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.

43 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first three months of 2014, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 Credits for coordinated congestion management: January through March, 2014[44]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[45]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/NYIS Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

In the first three months of 2014, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The firm flow entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the

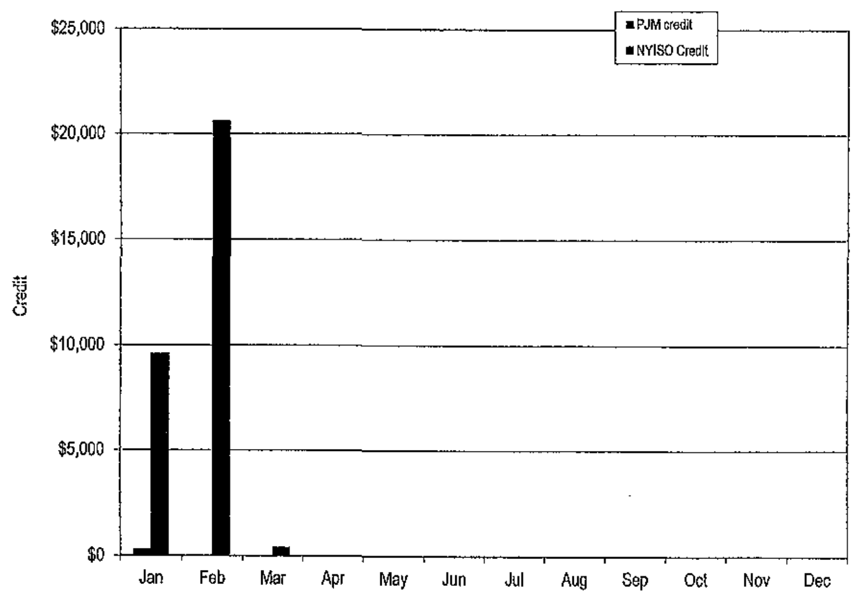
44 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

45 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 29, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2014).

approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the *non-monitoring RTO for congestion relief provided by the* non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

In the first three months of 2014, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (flowgates): January through March, 2014[46]

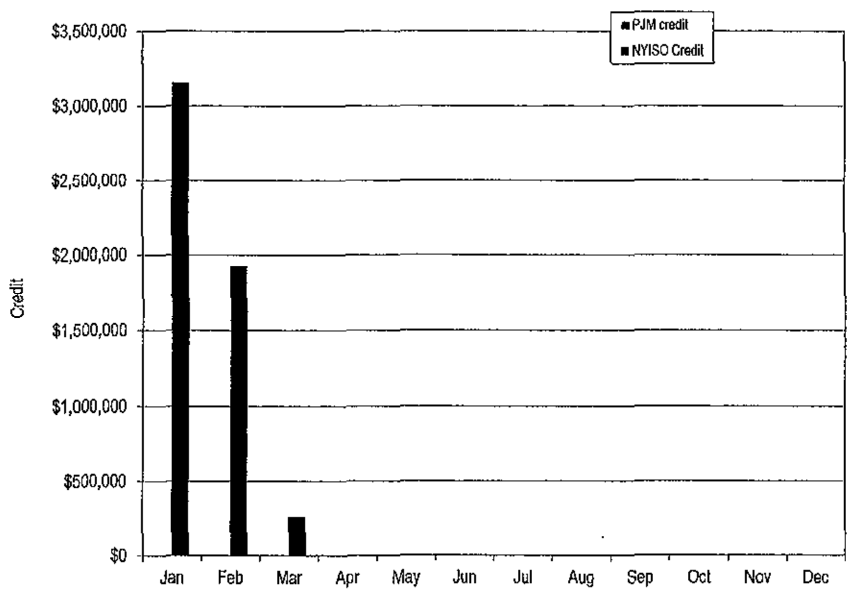


The M2M coordination process focuses on real-time market coordination to *manage transmission limitations that occur on the M2M Flowgates in a more* cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the PJM/NYIS border. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[47] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first three months of 2014, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

46 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

47 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, LLC," (January 29, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2014).

Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): January through March, 2014[48]



The PJM/NYISO JOA includes a provision that allows either party to suspend M2M operations when daily congestion charges exceed $500,000. On July 8, 2013, M2M congestion charges exceeded $500,000. These congestion charges were the result of its inability to meet the Ramapo PAR target values during thunderstorm alerts (TSA) called by the NYISO. During times when actual or anticipated severe weather conditions exist in the New York City area, the NYISO issues a TSA and operates in a more conservative manner, by reducing transmission transfer limits, which affects PJM's ability to meet the PAR targets. On July 12, 2013, PJM requested the suspension of M2M coordination for all TSA flowgates. PJM and NYISO are working together to develop additional operating and coordination procedures to ensure M2M processes continue to produce a just and reasonable result.

PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a yearly basis. The agreement continued to be in effect in the first three months of 2014.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[49] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[50] The existing JOA depended on the specific characteristics of PEC as a standalone company. The merged company has not engaged in discussions with PJM on this topic. The existing JOA does not apply to the merged company and should be terminated. The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

48 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

50 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement continued to be in effect in the first three months of 2014.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[51] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

Table 9-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2014

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$72.63	$75.86	$67.15	$67.15	$5.48	$8.71
PEC	$74.36	$80.82	$67.15	$67.15	$7.20	$13.66
NCMPA	$74.38	$74.95	$67.15	$67.15	$7.23	$7.80

51 See *PJM Interconnection, LLC*, Docket No. ER10-2710-000 (September 17, 2010).

Table 9-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2014

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$73.63	$76.45	$67.03	$66.91	$6.60	$9.54
PEC	$77.94	$80.37	$67.03	$66.91	$10.90	$13.46
NCMPA	$75.28	$75.49	$67.03	$66.91	$8.25	$8.58

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey including lines controlled by PJM.[52] This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001.[53]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009, a settlement on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[54] By order issued September 16, 2010, the Commission approved this settlement,[55] which extends Con Edison's special protocol indefinitely. The Commission approved transmission service agreements provide for Con Edison to take firm point-to-point service going forward under the PJM OATT. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[56] The settlement defined Con Edison's cost

52 See "Section 4 – Energy Market Uplift" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
53 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
54 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.
55 *132 FERC ¶ 61,221 (2010).*
56 *See, e.g.,* Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. Con Edison is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[57] Con Edison's rolled over service became effective on May 1, 2012. At that time, Con Edison became responsible for the entire 1,000 MW of transmission service and all associated charges and credits.

On December 11, 2013, the PJM Board approved changes to the Regional Transmission Expansion Plan (RTEP), which included approximately $1.5 billion in additional baseline transmission enhancements and expansions.[58] On January 10, 2014, in accordance with Schedule 12 of the PJM Tariff[59], PJM filed cost assignments for those upgrades. Using the hybrid cost allocation methodology approved by the Commission in Docket No. ER13-90-000 on March 22, 2013, PJM calculated Con Edison's cost responsibility assignment as approximately $629 million. On February 10, 2014, Con Edison filed a protest to the cost allocation proposal.[60] Con Edison asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the Con Edison zone is unjust and unreasonable. On March 7, 2014, PJM submitted a motion for leave to answer and limited answer to the protest submitted by Con Edison.[61] PJM's response points out that the filed and approved RTEP cost allocation process was followed, and that Con Edison's cost assignment responsibilities were addressed by the Settlement agreement and Schedule 12 of the PJM Tariff.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM issued three TLRs of level 3a or higher in the first three months of 2014, compared to eight TLRs issued in the first three months of 2013. The number of different flowgates for which PJM declared TLRs decreased from five in the first three months of 2013 to three in the first three months of 2014. The total MWh of transaction curtailments decreased by 93.4 percent from 28,062 MWh in the first three months of 2013 to 1,852 MWh in the first three months of 2014.

MISO called fewer TLRs of level 3a or higher in the first three months of 2014 than in the first three months of 2013. MISO TLRs decreased from 107 in the first three months of 2013 to 60 in the first three months of 2014.

NYISO called fewer TLRs of level 3a or higher in the first three months of 2014 than in the first three months of 2013. NYISO TLRs decreased from two in the first three months of 2013 to one in the first three months of 2014.

57 The terms of the settlement state that Con Edison shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.
58 See the *2013 State of the Market Report for PJM*, Volume II, Section 12, "Planning," for a more detailed discussion.
59 See PJM OATT, Schedule 12, Transmission Enhancement Charges, (February 1, 2013) pp 581-595.
60 See *Consolidated Edison Company of New York, Inc.* Docket No. ER14-972-000 (February 10, 2014).
61 See *PJM Interconnection LLC* Docket No. ER14-972-000 (March 7, 2014).

Table 9-27 PJM MISO, and NYISO TLR procedures: January, 2010 through March, 2014[62]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-11	7	8	29	5	5	4	75,057	14,071	156,508
Feb-11	6	7	10	5	4	2	6,428	23,796	27,649
Mar-11	0	14	28	0	5	3	0	10,133	57,472
Apr-11	3	23	12	3	9	3	8,129	44,855	15,761
May-11	9	15	15	4	7	4	18,377	36,777	24,857
Jun-11	15	14	24	7	6	9	17,865	19,437	31,868
Jul-11	7	8	17	4	7	7	18,467	3,697	20,645
Aug-11	4	6	4	4	4	2	3,624	11,323	12,579
Sep-11	7	17	7	6	7	3	6,462	25,914	11,445
Oct-11	4	16	5	2	6	1	16,812	27,392	3,665
Nov-11	0	10	2	0	5	2	0	22,672	484
Dec-11	0	5	8	0	3	2	0	8,659	26,523
Jan-12	1	9	5	1	6	2	4,920	6,274	8,058
Feb-12	4	6	16	2	6	2	0	5,177	35,451
Mar-12	1	11	10	1	6	2	398	31,891	26,761
Apr-12	0	14	11	0	7	1	0	8,408	29,911
May-12	2	17	12	1	10	5	3,539	30,759	21,445
Jun-12	0	24	0	0	7	0	0	31,502	0
Jul-12	11	19	1	5	4	1	34,197	46,512	292
Aug-12	8	13	0	1	6	0	61,151	13,403	0
Sep-12	2	5	0	1	4	0	21,134	12,494	0
Oct-12	3	9	0	2	6	0	0	12,317	0
Nov-12	4	10	5	2	6	2	444	24,351	6,250
Dec-12	1	22	0	1	12	0	0	17,761	0
Jan-13	4	42	2	3	17	1	13,453	103,463	1,045
Feb-13	4	26	0	3	10	0	14,609	66,086	0
Mar-13	0	39	0	0	13	0	0	53,122	0
Apr-13	1	45	0	1	20	0	84	64,938	0
May-13	10	29	0	7	14	0	879	20,778	0
Jun-13	4	25	1	1	11	1	5,036	76,240	4,102
Jul-13	12	28	0	2	9	0	88,623	80,328	0
Aug-13	4	19	0	4	8	0	3,469	38,608	0
Sep-13	6	33	0	5	14	0	7,716	90,188	0
Oct-13	2	42	0	1	20	0	534	72,121	0
Nov-13	2	27	0	2	8	0	11,561	52,508	0
Dec-13	0	16	0	0	5	0	0	20,257	0
Jan-14	3	20	0	3	10	0	1,852	11,683	0
Feb-14	0	29	1	0	10	1	0	33,189	991
Mar-14	0	11	0	0	7	0	0	14,842	0

62 The curtailment volume for PJM TLRs was taken from the individual NERC TLR history reports as posted in the interchange distribution calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLRs was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx> (Accessed April 17, 2014).

Table 9-28 Number of TLRs by TLR level by reliability coordinator: January through March, 2014

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2014	ICTE	0	0	0	0	0	0	0
	MISO	35	18	0	4	2	0	59
	NYIS	1	0	0	0	0	0	1
	ONT	1	0	0	0	0	0	1
	PJM	2	1	0	0	0	0	3
	SOCO	3	0	0	0	0	0	3
	SWPP	65	26	0	22	13	0	126
	TVA	12	20	2	5	4	0	43
	VACS	6	14	2	2	0	0	24
Total		125	79	4	33	19	0	260

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[63]

Following elimination of the requirement to procure transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 215,829 bids per day, with an average cleared volume of 1,486,359 MWh per day, in the first three months of 2014, compared to an average of 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013 (See Figure 9-13).

Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding. The FTR forfeiture rule does not currently apply to UTCs.

63 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Figure 9-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through March, 2014

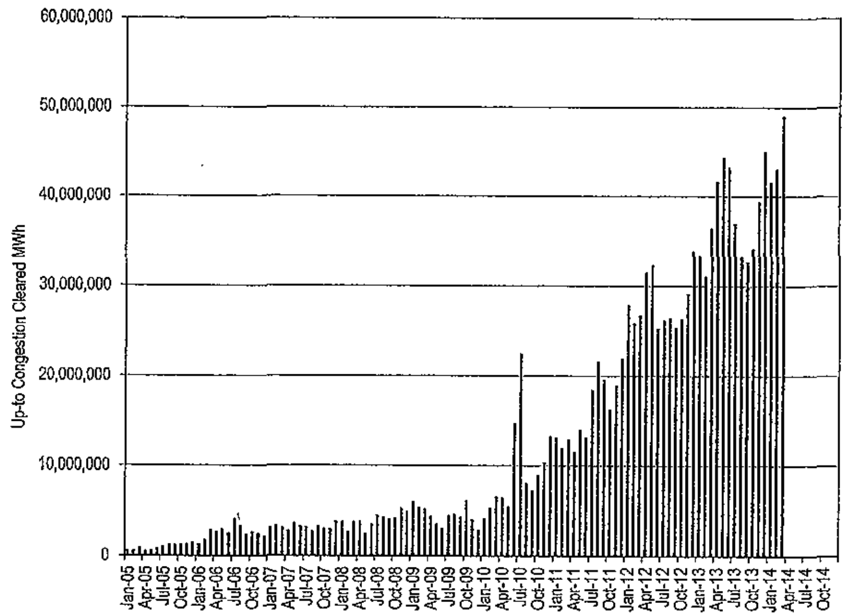


Table 9-29 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2014

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	4,218,910	5,787,961	319,122	-	10,325,993	90,277	74,826	6,042	-	171,145	2,591,211	3,242,491	202,854	-	6,036,556	56,132	45,303	4,210	-	105,645
Feb-09	3,580,115	4,904,467	318,440	-	8,803,022	64,338	70,874	6,347	-	141,559	2,374,734	2,836,344	203,907	-	5,414,985	42,101	44,423	4,402	-	90,926
Mar-09	3,649,978	5,164,186	258,701	-	9,072,865	64,714	72,495	5,531	-	142,740	2,285,412	2,762,459	178,507	-	5,226,378	42,408	42,007	4,299	-	88,714
Apr-09	2,607,303	5,085,912	73,931	-	7,767,146	47,970	67,417	2,146	-	117,533	1,797,302	2,582,294	48,478	-	4,428,074	32,088	35,987	1,581	-	69,656
May-09	2,196,341	4,063,887	106,860	-	6,367,088	40,217	54,745	1,304	-	96,266	1,496,396	2,040,737	77,553	-	3,614,686	26,274	29,720	952	-	56,946
Jun-09	2,598,234	3,132,478	164,903	-	5,895,615	47,625	44,755	2,873	-	95,253	1,540,169	1,500,560	88,723	-	3,129,452	28,565	23,307	1,522	-	53,394
Jul-09	3,984,680	3,776,957	296,910	-	8,058,547	67,039	56,770	5,183	-	128,992	2,465,891	1,902,807	163,129	-	4,531,826	41,924	31,176	2,846	-	75,946
Aug-09	3,551,396	4,388,435	260,184	-	8,200,015	64,652	64,052	3,496	-	132,200	2,278,431	2,172,133	194,415	-	4,644,978	41,774	34,576	2,421	-	78,771
Sep-09	2,948,353	4,179,427	156,270	-	7,284,050	51,006	64,103	2,405	-	117,514	1,774,589	2,479,898	128,344	-	4,382,831	31,962	40,698	1,944	-	74,604
Oct-09	3,172,034	6,371,230	154,825	-	9,698,089	46,989	100,350	2,217	-	149,556	2,060,371	3,931,346	110,646	-	6,102,363	31,634	70,964	1,672	-	104,270
Nov-09	3,447,356	3,851,334	103,325	-	7,402,015	53,067	61,906	1,236	-	116,209	2,065,813	1,932,595	51,929	-	4,050,337	33,769	32,916	653	-	67,338
Dec-09	2,323,383	2,502,529	66,497	-	4,892,409	47,099	47,223	1,430	-	95,752	1,532,579	1,359,936	34,419	-	2,926,933	31,673	28,478	793	-	60,944
Jan-10	3,794,946	3,097,524	212,010	-	7,104,480	81,604	55,921	3,371	-	140,896	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337	6,063,803	6,650,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927	12,675,852	12,311,609	250,024	-	25,237,486	355,731	295,911	6,891	-	658,533
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,828	1,631,255	2,832,425	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	22,597,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749	5,116,607	6,350,080	454,289	21,958,089	33,879,066	180,592	224,830	24,459	820,991	1,250,872
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Apr-13	14,538,907	17,419,505	1,337,680	105,927,107	139,223,200	358,245	364,008	47,048	2,275,846	3,045,147	4,413,047	4,834,302	315,867	32,152,243	41,715,459	145,860	157,031	16,315	892,562	1,211,768

Table 9-29 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2014 *(continued)*

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
May-13	16,565,868	17,640,682	1,640,097	115,572,648	151,419,296	431,892	389,254	54,873	2,660,793	3,536,812	4,556,277	4,747,887	333,677	34,778,962	44,416,803	144,444	144,482	16,317	944,116	1,249,359
Jun-13	16,698,203	18,904,971	1,337,373	128,595,957	165,536,504	452,145	433,010	48,007	3,384,811	4,317,973	3,823,166	4,280,538	312,158	34,935,141	43,351,002	143,223	151,603	17,518	1,116,318	1,428,662
Jul-13	15,436,914	16,428,662	1,473,144	116,673,912	150,012,631	430,120	387,969	49,712	3,075,624	3,943,425	3,250,706	3,502,990	320,374	29,883,430	36,957,500	131,535	127,032	17,948	957,260	1,233,775
Aug-13	12,332,984	14,354,140	1,370,624	89,306,595	117,364,344	328,835	326,637	40,325	2,223,269	2,919,066	2,862,764	3,232,565	309,069	26,900,995	33,305,393	111,715	122,061	16,299	848,490	1,098,555
Sep-13	10,767,257	11,322,974	729,332	75,686,010	98,505,573	264,095	262,486	21,968	1,976,741	2,525,290	2,962,619	3,467,611	221,329	26,044,742	32,696,300	102,984	107,604	10,233	792,766	1,013,587
Oct-13	9,081,257	11,106,943	853,397	86,857,535	107,899,131	280,821	338,374	31,031	2,524,127	3,174,353	2,201,219	3,532,253	186,113	28,243,584	34,163,168	108,189	145,667	11,551	1,002,832	1,268,239
Nov-13	9,219,216	15,052,563	1,307,989	98,027,480	123,607,248	267,704	394,031	39,095	3,167,638	3,868,468	2,640,001	3,986,788	332,814	32,437,908	39,397,511	112,850	154,379	13,958	1,238,589	1,519,776
Dec-13	9,934,234	16,089,101	1,696,981	118,916,149	146,636,465	286,295	404,788	42,367	3,691,770	4,425,220	3,189,261	3,234,196	503,666	38,150,077	45,077,200	119,954	122,683	14,318	1,382,736	1,639,691
Jan-14	10,359,891	16,047,391	2,326,490	119,848,848	148,582,620	350,248	469,176	47,801	4,382,482	5,249,707	2,594,374	3,172,914	460,495	35,413,440	41,641,223	116,316	143,021	15,323	1,537,418	1,812,078
Feb-14	11,351,094	14,846,332	1,854,617	126,008,272	154,060,316	382,148	480,055	47,526	5,151,647	6,061,376	2,764,565	3,247,481	362,670	36,715,916	43,090,631	132,870	147,766	14,045	1,897,337	2,192,018
Mar-14	14,669,735	17,135,117	1,949,978	147,142,336	180,897,166	515,877	516,871	54,575	7,026,221	8,113,544	3,442,624	3,293,865	341,620	41,962,312	49,040,421	165,663	148,671	15,214	2,290,716	2,620,264
TOTAL	1,050,843,817	1,043,289,049	55,462,419	1,697,438,527	3,847,033,812	24,263,557	22,403,801	1,286,828	51,812,893	99,767,079	380,206,775	373,968,703	22,219,114	507,716,220	1,284,110,812	9,919,410	9,048,733	515,031	18,332,553	37,815,727

In the first three months of 2014, the cleared MW volume of up-to congestion transactions was comprised of 6.6 percent imports, 7.3 percent exports, 0.9 percent wheeling transactions and 85.3 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load which can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.

Elimination of Ontario Interface Pricing Point

An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy.

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[64] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control Area as specified on the NERC Tag. Transactions between PJM and external balancing authorities need to be priced at the PJM border.

The IMO Interface Pricing Point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO Interface Pricing Points. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

The IMO Interface Pricing Point is defined as the LMP at the Bruce bus, which is located in IESO. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The non-contiguous nature of the Ontario Interface Pricing Point creates over payments or additional credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. Of the 1,035 GWh of the net scheduled transactions between PJM and IESO, 912 GWh wheeled through MISO in the first three months of 2014 (see Table 9-22).

The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.[65]

64 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed April 17, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

65 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

PJM and NYISO Coordinated Interchange Transaction Proposal

The coordinated transaction scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price from the ITSCED results with the NYISO. The NYISO compares the PJM/NYISO Interface Price with its RTC calculated NYISO/PJM Interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

On December 13, 2013, PJM submitted proposed revisions to the PJM Operating Agreement, and parallel provisions of the PJM Tariff, to implement CTS.[66] This filing requested that the Commission issue an order accepting the proposed revisions by no later than February 13, 2014 to allow for adequate time to develop the infrastructure necessary to implement CTS in November, 2014. The Commission issued an order conditionally accepting the tariff revisions on February 20, 2014, for implementation on the later of November, 2014, or the date that CTS becomes operational, subject to the submission of an informational filing informing the Commission of the acceptance of ITSCED forecasting accuracy standards, and an additional revised tariff no later than fourteen days prior to the official implementation date of CTS.[67]

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2013. Table 9-30 shows that over all forecast ranges ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 31.8 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.59. In 4.2 percent of all intervals, the

66 See PJM Interconnection, LLC, OA Schedule 1 and Attachment K Revisions, Docket No. ER14-623-000. (December 13, 2013).

67 146 FERC ¶ 61,096 (2014).

average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20, with an average price difference of $56.39, and in 6.5 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was greater than -$20, with an average price difference of $45.23.

Table 9-30 ITSCED/real-time LMP - PJM/NYIS interface price comparison (all intervals): 2013

Range	Percent of All Intervals	Average Price Difference
> $20	4.2%	$56.39
$10 to $20	3.6%	$14.27
$5 to $10	4.9%	$7.06
$0 to $5	31.8%	$1.59
-$5 to $0	38.1%	$1.67
-$10 to -$5	6.6%	$7.07
-$20 to -$10	4.3%	$14.26
< -$20	6.5%	$45.23

Table 9-31 ITSCED/real-time LMP - PJM/NYIS interface price comparison (by interval): 2013

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	5.8%	$59.57	4.1%	$51.80	2.4%	$47.60	3.3%	$62.21
$10 to $20	4.5%	$14.46	3.7%	$14.18	2.6%	$14.50	2.9%	$14.07
$5 to $10	6.1%	$7.20	4.9%	$7.11	4.4%	$6.99	3.7%	$6.92
$0 to $5	31.3%	$1.70	34.6%	$1.64	34.0%	$1.53	30.7%	$1.43
-$5 to $0	34.1%	$1.78	35.5%	$1.67	40.2%	$1.56	43.5%	$1.58
-$10 to -$5	6.8%	$7.14	6.3%	$7.07	6.5%	$7.02	6.8%	$7.07
-$20 to -$10	4.3%	$14.38	4.5%	$14.31	4.1%	$14.07	4.1%	$14.03
< -$20	7.0%	$40.95	6.4%	$49.12	5.8%	$46.64	5.0%	$50.05

The ITSCED application runs approximately every 5 minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. As the ITSCED utilizes closer to real-time data in its cases, the expectation would be that the accuracy of the forecasted interface prices would improve. Table 9-31 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-31 shows that while there is some improvement as the forecast gets closer to real time, a substantial range of forecast errors remain even in the thirty-minute ahead forecast. In the final ITSCED results prior to real time, in 74.2 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5 of the actual PJM/NYIS interface real-time LMP, compared to 65.4 percent in the 135 minute ahead ITSCED results.

While in only 8.3 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20 in the thirty-minute ahead cases, the average price differences were $62.21 when the price difference was greater than $20, and $50.05 when the price difference was greater than -$20.

The NYISO will utilize PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO will approve CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the ITSCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences in forecasted LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to implement the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

It does not appear that ITSCED can accurately predict real-time PJM/NYIS interface prices. But as long as the risk associated with CTS transactions remains entirely with market participants, it is the participants who should be concerned about the accuracy of the forecasts and the participants who take the risks associated with the accuracy of the forecasts.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations mostly addresses these concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM (Table 9-32 shows that there have been no uncollected congestion charges since the inception of the business rule change on April 12, 2013.) There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be necessary in the future to address this exposure.

Table 9-32 Monthly uncollected congestion charges: January, 2010 through March, 2014

Month	2010	2011	2012	2013	2014
Jan	$148,764	$3,102	$0	$5	$0
Feb	$542,575	$1,567	($15)	$249	$0
Mar	$287,417	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	
May	$41,025	$0	($27)	$0	
Jun	$169,197	$1,354	$78	$0	
Jul	$827,617	$1,115	$0	$0	
Aug	$731,539	$37	$0	$0	
Sep	$119,162	$0	$0	$0	
Oct	$257,448	($31,443)	($6,870)	$0	
Nov	$30,843	($795)	($4,678)	$0	
Dec	$127,176	($659)	($209)	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0

Spot Imports

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[68] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network

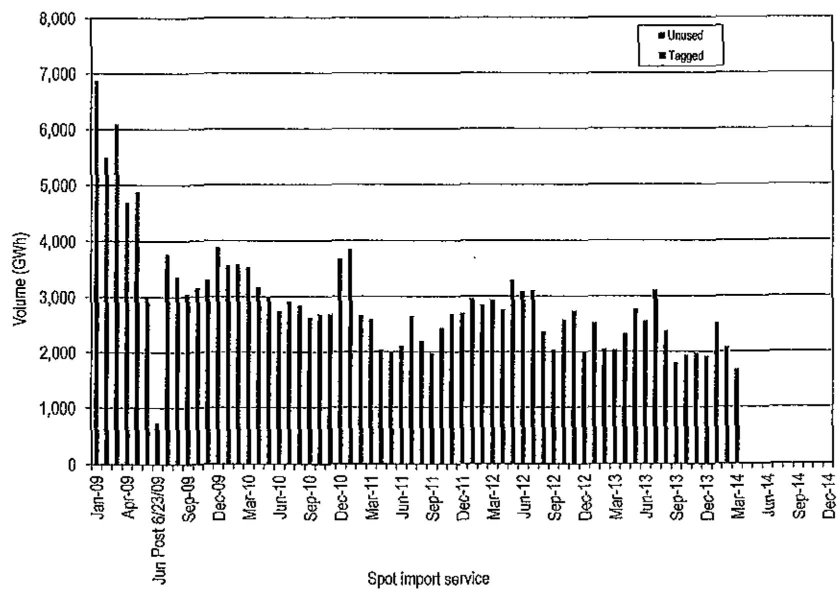
68 See "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (Accessed April 17, 2014).

service) is provided at no charge to the market participant offering into the PJM spot market.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding.

The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

Figure 9-14 Spot import service utilization: January, 2009 through March, 2014



Real-Time Dispatchable Transactions

Real-time dispatchable transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted in the first three months of 2014.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service.[1] PJM provides scheduling, system control and dispatch and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for the first three months of 2014.

Table 10-1 The Regulation Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 97 percent of the hours in the first three months of 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first three months of 2014 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

Table 10-2 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, 12 percent of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to *the market to ensure that market power cannot be exercised at times of* system stress.

Overview

Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance *score translate a resource's capability (actual) MW into effective MW.*

Market Structure

- **Supply.** In the first three months of 2014, the average hourly eligible supply of regulation was 1,378 actual MW (1,016 effective MW). This is a decrease of 110 actual MW (169 effective MW) from the first three months of 2013 when the average hourly eligible supply of regulation was 1,488 actual MW (1,185 effective MW).
- **Demand.** The average hourly regulation demand was 685 actual MW (664 effective MW) in the first three months of 2014. This is a 152 actual MW (45 effective MW) decrease in the average hourly regulation demand of 837 actual MW (708 effective MW) in the same period of the first three months of 2013.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 2.01. This is a 13.4 percent increase over the first three months of 2013 when the ratio was 1.77.
- **Market Concentration.** In the first three months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1972 which is classified as highly concentrated. In the first three months of 2014, the three pivotal supplier test was failed in 97 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[3] As of March 31, 2014, there were 261 resources following the RegA signal and 38 resources following the RegD signal.

3 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $91.94 per MW of regulation in the first three months of 2014, an increase of $58.24 per MW of regulation, or 172.8 percent, from the first three months of 2013. The cost of regulation in the first three months of 2014 was $111.02 per MW of regulation, a $72.28 per MW of regulation, or 186.6 percent, increase from the first three months of 2013.
- **RMCP Credits.** RegD resources continue to be underpaid relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. In the first three months of 2014, RegA resources received RMCP credits per effective MW on average 2.1 times higher than RegD resources. If the Regulation Market were functioning correctly, RegD and RegA resources would be paid equally per effective MW.

Synchronized Reserve Market

Synchronized reserve is a component of primary reserve. The Tier 2 Synchronized Reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD). The MAD subzone is designed to ensure that transmission constraints will not prevent adequate synchronized reserves from being available in MAD when called. PJM has the right to define new zones or subzones "as needed for system reliability."[4]

Market Structure

- **Supply.** In the first three months of 2014, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The synchronized reserve requirement for the RTO Synchronized Reserve Zone remained at 1,375 MW where it was set in November 2012. The synchronized reserve requirement for the Mid-Atlantic Dominion Reserve Subzone remained at 1,300 MW where it was set in July 2010.
- **Supply and Demand.** All on-line generation resources are required to offer synchronized reserve. In the first three months of 2014, the ratio of on-line tier 2 offered synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 3.02 averaged over all hours. The highest offered to required ratio was 3.99 on January 31 and the lowest was 1.77 on March 31. For the RTO Synchronized Reserve Zone the ratio was 8.85. The highest offered to required ratio was 10.46 on January 1 and the lowest was 6.62 on March 27.
- **Market Concentration.** In the first three months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 4236 which is classified as highly concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 14.0 percent of all tier 2 synchronized reserve) was 8743. In the first three months of 2014, 56 percent of hours had a maximum market share greater than 40 percent. The MMU calculates that during the first three months of 2014, 57.9 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone if PJM had such a test and 37.7 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone if PJM had such a test.

The MMU concludes from these results that both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market in the first three months of 2014 were characterized by structural market power.

Market Conduct

- **Offers.** Synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM.

4 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 66.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) Subzone was $26.46 per MW in the first three months of 2014, a $19.11 increase from the first three months of 2013. The cost of tier 2 synchronized reserves per MW in MAD in the first three months of 2014 was $33.48, a $20.90 increase the cost of synchronized reserve in the first three months of 2013. For the MAD Subzone the market clearing price was 79 percent of the synchronized reserve cost per MW in the first three months of 2014, an increase from the 60 percent in the first three months of 2013.

  The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $50.90 per MW in the first three months of 2014. The cost for tier 2 synchronized reserve in RTO Synchronized Reserve Zone was $100.53. For the RTO Synchronized Reserve Zone the market clearing price was 50.6 percent of the synchronized reserve cost per MW in the first three months of 2014.

- **Supply and Demand.** A synchronized reserve shortage occurs when the combination of tier 1 and tier 2 synchronized reserve supply is not adequate to meet the synchronized reserve requirement. The synchronized reserve requirement did not change for either the RTO Reserve Zone or the Mid-Atlantic Dominion Subzone during the first three months of 2014. There were four hours of synchronized reserve shortage in the first three months of 2014 on January 7, 2014. The shortage was in both the RTO Zone and the MAD subzone.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and shares its market definitions including the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the *direction of PJM dispatch.*

Market Structure

- **Supply.** With the exception of two hours on January 6, 2014, and eight hours on January 7, 2014, the supply of offered and eligible tier 2 synchronized reserve for the period spanning January 1, 2014 through March 31, 2014 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** In the RTO Zone the market cleared an hourly average of 37.8 MW of non-synchronized reserve of which 86.9 percent of cleared non-synchronized reserve was at a price of $0. In the MAD subzone, the market cleared an hourly average of 560 MW of non-synchronized reserve of which 92.7 percent was at a price of $0.
- **Supply and Demand.** The requirement for primary reserve is 1.5 times the largest contingency. There is no specific requirement for non-synchronized reserve. In the RTO Reserve Zone the primary reserve requirement is 2,063 MW. Of that 2,063 MW 1,375 MW must be synchronized to the grid. All or any portion of the remaining 688 MW is a jointly optimized solution of tier 2 synchronized reserve, tier 1 synchronized reserve, and non-synchronized reserve. In the MAD subzone the primary reserve requirement is 1,700 MW of which 1,300 MW must be synchronized to the grid. All or any portion of the remaining 400 MW can be non-synchronized reserve.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for Non-Synchronized Reserves by the market solution software.

Market Performance

- Price. Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $2.02 per MW for the first three months of 2014. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) Subzone was $4.56 per MW.

Day-Ahead Scheduling Reserve (DASR)

The purpose of the DASR Market is to satisfy secondary supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[5]

Market Structure

- Concentration. The MMU calculates that in the first three months of 2014, zero hours in the DASR market would have failed the three pivotal supplier test.
- Supply. The DASR market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. Eligible DASR resources consist of all resources that can provide reserve capability that can be fully converted into energy within 30 minutes as requested by PJM dispatchers.
- Demand. The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013.

Market Conduct

- Withholding. Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On March 31, 2014, 56.4 percent of resources offered at $0, 65.9 percent of resources offered at $0.05 or less, 74.4 percent of resources offered at less than $1.00, and 11.5 percent resources offered at above $5 per MW.
- DR. Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in the first three months of 2014.

Market Performance

- Price. The DASR market clearing price in the first three months of 2014 was $0.06 per MW. This is a 100 percent increase from the first three months of 2013 which had a weighted price of $0.03 per MW.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[6]

In the first three months of 2014, total black start charges were $12.7 million with $5.1 million in revenue requirement charges and $7.6 million in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in the first three months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $28,280) to $3.50 per MW-day in the AEP Zone (total charges were $7,202,857).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on

5 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

6 OATT Schedule 1 § 1.3BB.

the transmission system and is essential to the flow of real power (measured in MW).

In the first three months of 2014, total reactive service charges were $77.7 million with $70.2 million in revenue requirement charges and $7.5 million in operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. Total charges in the first three months of 2014 ranged from $487 in the RECO Zone to $10.1 million in the AEP Zone.

Ancillary Services Costs per MWh of Load: January through March, 2003 through 2014

Table 10-4 shows PJM ancillary services costs for the first three months of years 2003 through 2014, on a per MWh of load basis. The rates are calculated as the total charges for the specified ancillary service divided by the total real time load in MWh for the first three months of 2014 (212.3 million MWh). The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. Supplementary operating reserve includes day-ahead operating reserve; balancing operating reserve; and synchronous condensing. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary in per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and also changes in the volume of each ancillary service purchased. As an example, the Regulation Market clearing price increased 172.8 percent (from $33.70 to $91.94 per MW of regulation capability), the cost of regulation per MWh of real time load increased only 125.0 percent (from $0.28 to $0.63 per MWh of real time load).

Table 10-4 History of ancillary services costs per MWh of Load: January through March, 2003 through 2014

Year (Jan-Mar)	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2003	$0.65	$0.59	$0.22	$0.00	$0.98	$2.43
2004	$0.53	$0.63	$0.26	$0.17	$0.89	$2.48
2005	$0.46	$0.51	$0.25	$0.07	$0.57	$1.86
2006	$0.48	$0.46	$0.28	$0.09	$0.32	$1.62
2007	$0.58	$0.46	$0.30	$0.11	$0.50	$1.95
2008	$0.59	$0.47	$0.29	$0.07	$0.52	$1.94
2009	$0.37	$0.37	$0.34	$0.16	$0.56	$1.80
2010	$0.34	$0.38	$0.35	$0.05	$0.68	$1.80
2011	$0.27	$0.33	$0.39	$0.12	$0.84	$1.95
2012	$0.18	$0.41	$0.49	$0.03	$0.53	$1.64
2013	$0.28	$0.41	$0.63	$0.04	$0.94	$2.30
2014	$0.63	$0.38	$0.37	$0.56	$3.55	$5.49

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process.
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM consider replacing the DASR

Market with a real time secondary reserve product that is available and dispatchable in real time.

- The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market.

Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012.[7]

Market Design

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE. RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. Resources must qualify to follow the RegA and RegD signals. Resources must qualify for one signal or both signals, but will be assigned by the market clearing engine to follow only one signal within a given market hour. The PJM Regulation Market design includes three clearing price components (capability, performance,

7 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[8]

While resources following RegA and RegD can both provide regulation service in PJM's regulation market, PJM's joint optimization is designed to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD resources into a common unit of measure via a marginal benefit factor (MBF). The marginal benefit factor is a measure of the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The marginal benefit factor and the performance score of the resource are used to convert RegA and RegD resource regulation capability MW into comparable units, termed effective MW. Resource-specific marginal benefit factors are defined for each resource separately while the market marginal benefit factor is the marginal benefit factor of the last RegD resource cleared in the market. Effective MW, supplied from RegA or RegD resources, are defined in terms of RegA MW. Except where expressly referred to as effective MW or effective regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

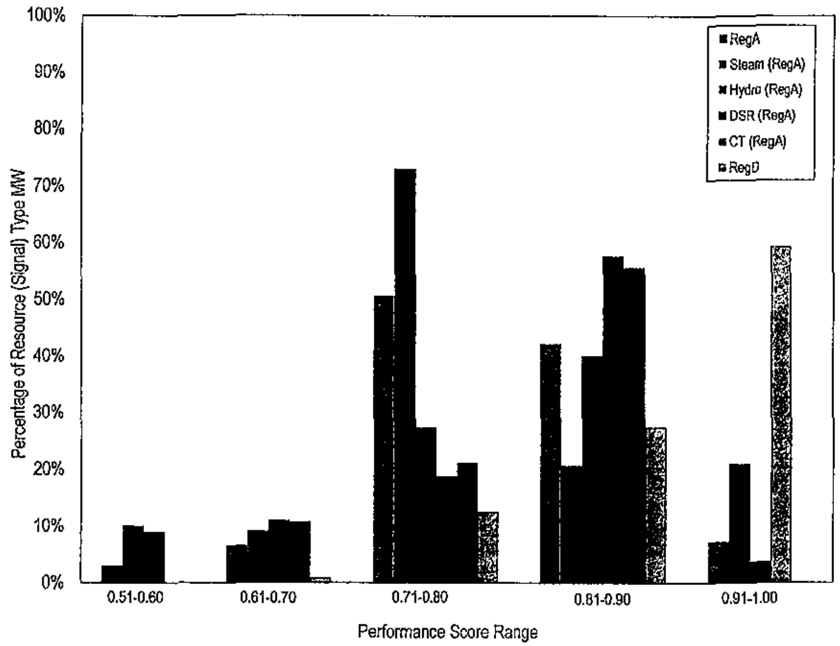
PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in what are termed to be dollars per unadjusted regulation capability MW. The Regulation Market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The five-minute RMCP is the sum of the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

Resources are paid by RMCP credits (the sum of RMCCP credits and RMPCP credits) and lost opportunity cost credits. RMCCP credits are calculated as MW of regulation capability times performance score times RMCCP. RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. RMCP credits are calculated as RMCCP credits plus RMPCP credits. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference.

Figure 10-1 shows the average performance score by resource type and signal followed for the first three months of 2014. In this figure, the MW used are unadjusted regulation capability MW and the performance score is the actual within hour (as opposed to the historic 100-hour moving average) performance score of the regulation resource. Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. Resources following the RegD signal tend to follow the RegD signal more closely than resources following the RegA signal follow the RegA signal. That is, RegD resources tend to have higher performance scores. As the figure shows, 59.4 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 3.8 percent of RegA resources have average performance scores within that range.

8 PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

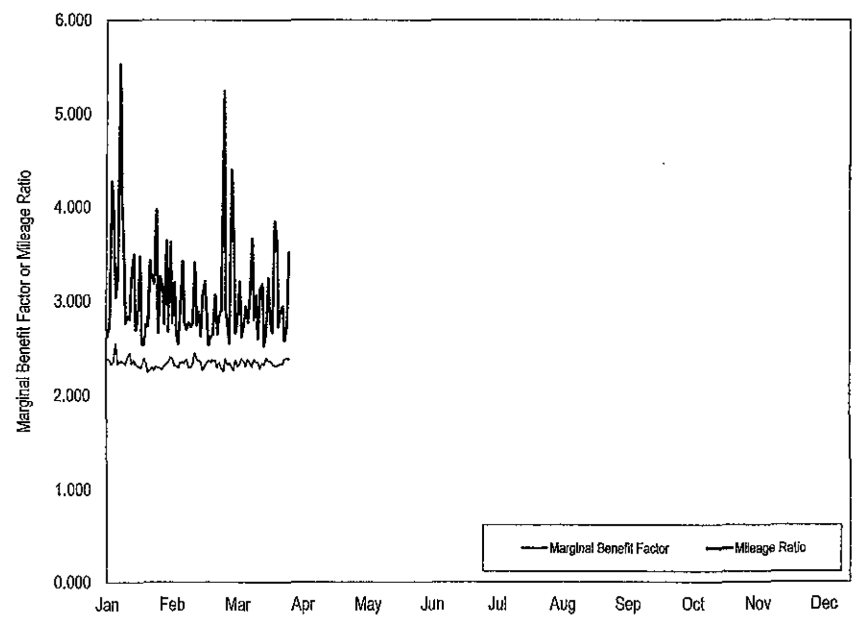
Figure 10-1 Hourly average performance score by unit type and regulation signal type: 2013



From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefit factor be fixed at one for settlement calculations only. As Figure 10-2 shows that the true marginal benefit factor, as used in the optimization and commitment process for regulation in the first three months of 2014, was always higher than one. This caused resources following the RegD signal to be underpaid. Resources following the RegD signal should have been paid the true market marginal benefit factor times the amount that they were actually paid. The market marginal benefit factor should have been applied to the capability and the performance payments of RegD resources.

On October 2, 2013, FERC directed PJM to eliminate the use of the marginal benefit factor completely from settlement calculations of the capability and performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[9] As Figure 10-2 demonstrates, the RegD to RegA mileage ratio is generally higher than the actual marginal benefit factor and much more variable. In this figure the mileage ratio is the actual hourly mileage ratio, calculated as the mileage provided by RegD resources divided by the mileage provided by RegA resources. The mileage multiplier has not brought total payment of RegD resources in line with RegA resources on a dollar per effective MW basis. This is, in part, due to the fact that the performance related price per MW of capability, which is the only part multiplied by the mileage ratio, is a relatively small portion of the total price per MW of capability.

Figure 10-2 Daily average marginal benefit factor and mileage ratio: January through March 2014



9 145 FERC ¶ 61,011 (2013).

Market Structure

Supply

Table 10-5 shows capability MW (actual), average daily offer MW (actual), average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in January through March 2014. In this table, actual MW are unadjusted regulation capability MW and effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor. A resource must be either generation or demand. But a resource can (and several resources currently do) choose to follow both signals. For that reason the sum of each signal type's capability can exceed the full regulation capability.

Table 10-5 PJM regulation capability, daily offer[10] and hourly eligible: January through March 2014[11]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,179.8	8,170.5	9.3	8,130.2	303.3
Offered MW	5,993.1	5,984.0	9.0	5,801.1	192.0
Actual Eligible MW	1,377.8	1,370.7	7.1	1,232.7	145.0
Effective Eligible MW	1,016.1	1,006.2	9.9	817.8	198.2
Actual Cleared MW	684.8	681.0	3.8	598.0	86.8
Effective Cleared MW	663.6	655.5	8.1	470.0	193.6

While total regulation capability MW provided by coal units declined from 189,372 MW in the first three months of 2013 to 173,842 MW in the first three months of 2014, the proportion of regulation provided by coal increased slightly, from 16.5 percent of regulation in the first three months of 2013 to 17.1 percent of regulation in the first three months of 2014. This was a result of PJM's reducing the regulation requirement for January through March 2014 compared to the regulation requirement for January through March, 2013. Coal unit revenues in the first three months of 2014 were 2.5 times the revenues in the first three months of 2013 ($27.3 million in the first three months of 2014, versus $10.9 million in the first three months of 2013). The increase was a result of the high regulation market clearing prices and out of market opportunity cost credits in January. Table 10-6 provides monthly data on the number of coal units providing regulation, the scheduled regulation in MW provided by coal units, the total scheduled regulation in MW provided by all resources, the percent of scheduled regulation provided by coal units, and the total credits received by coal units. In Table 10-6, the MW have been adjusted by the actual within-hour performance score since this adjustment forms the basis of payment for coal units providing regulation.

Table 10-6 PJM regulation provided by coal units

Year	Period	Number of Coal Units Providing Regulation	Adjusted Settled Regulation from Coal Units (MW)	Adjusted Settled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2013	Jan	117	80,766	401,101	20.1%	$5,376,060
2013	Feb	101	64,164	365,249	17.6%	$3,071,878
2013	Mar	96	44,443	372,154	11.9%	$2,473,951
2013	Jan-Mar Average	105	63,124	379,502	16.5%	$3,640,630
2014	Jan	109	70,441	360,513	19.5%	$15,780,551
2014	Feb	102	51,033	309,976	16.5%	$4,690,694
2014	Mar	101	52,368	341,089	15.4%	$6,860,625
2014	Jan-Mar Average	104	57,947	337,193	17.1%	$9,110,623

The supply of regulation can be affected by regulating units retiring from service. Table 10-7 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015. These retirements should not substantially impact the supply of regulation capability in PJM. The MW in Table 10-7 have been adjusted by the actual within-hour performance score.

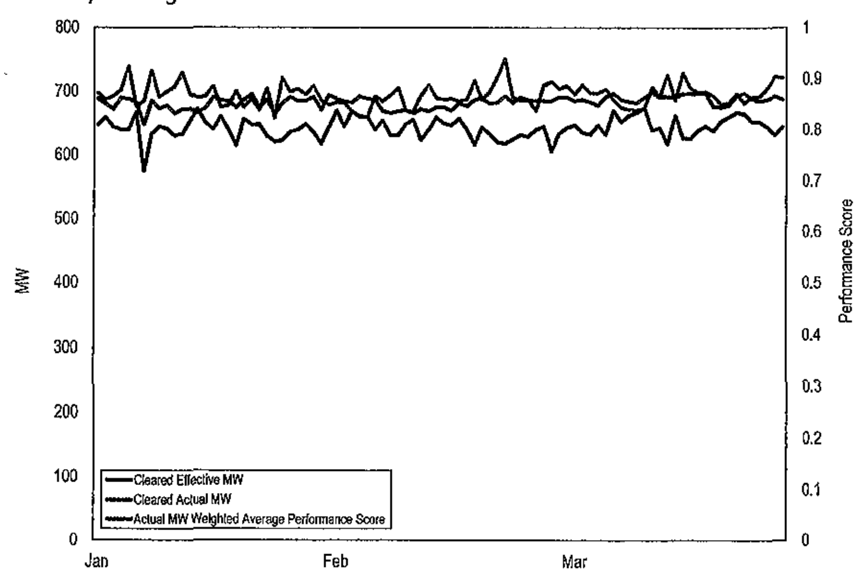
10 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
11 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 10-7 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through March 2014	Adjusted Settled MW, January through March 2014	Units Scheduled To Retire Through 2015	Adjusted Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
267	1,011,578	28	11,457	1.13%

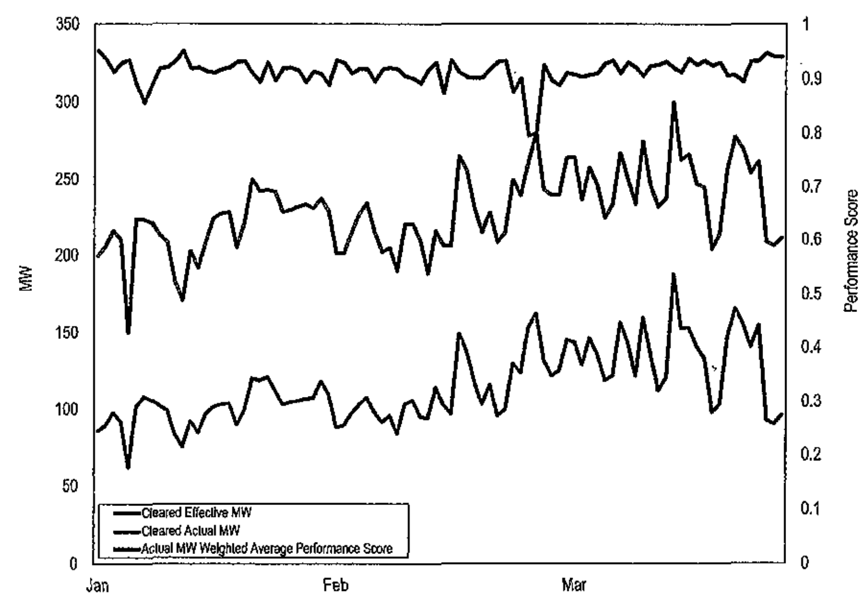
Although the marginal benefit factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in the first three months of 2014 because the average performance score was less than 1.00 (Figure 10-3). For the first three months of 2014, the MW-weighted average RegA performance score was 0.79 and as of March 31, 2014, there were 261 resources following the RegA signal.

Figure 10-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation: January through March 2014



In Figure 10-3 and Figure 10-4, actual MW are unadjusted for either performance score or benefit factor and effective MW are adjusted for the historic 100-hour moving average performance score and the resource-specific benefit factor.

Figure 10-4 RegD: Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units: January through March 2014



For RegD resources, the effective MW are higher than the actual MW because their marginal benefit factor at current participation levels is significantly greater than 1.0. In the first three months of 2014, the marginal benefit factor for cleared RegD following resources ranged from 1.613 to 2.672 with an average over all hours of 2.340. For the first three months of 2014, the MW-weighted average RegD resource performance score was 0.92 and as of March 31, 2014, there were 38 resources following the RegD signal.

The cost of each unit is calculated using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type offered, modified by resource marginal benefit factor and historic performance score. (The miles to MW ratio of the signal type offered is the historic 30-day moving average of requested mileage for that signal type per unadjusted regulation capability MW.)

As of October 1, 2012, a regulation resource's total offer is equal to the sum of its capability offer ($/MW) and performance offer ($/MW) and its estimated lost opportunity cost ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual opportunity cost and any applicable benefit factor, of the most expensive cleared regulation resource in each interval.

Since the implementation of regulation performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012, (Table 10-14). Throughout the first three months of 2014, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for the first three months of 2014 was $91.94/MW. The regulation cost for the first three months of 2014 was $111.02/MW. The ratio of price to cost is lower (83 percent) than in the same period in 2013 (87 percent) due to the extreme market conditions in January that resulted in increased out of market payments based on lost opportunity costs.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 1, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours.

Table 10-8 shows the average hourly required regulation by month and its relationship to the supply of regulation for both actual (unadjusted) and effective MW.

Table 10-8 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March, 2013 and 2014

Month	Average Required Regulation (MW), 2013	Average Required Regulation (MW), 2014	Average Required Regulation (Effective MW), 2013	Average Required Regulation (Effective MW), 2014	Ratio of Supply MW to MW Requirement, 2013	Ratio of Supply MW to MW Requirement, 2014	Ratio of Supply Effective MW to Effective MW Requirement, 2013	Ratio of Supply Effective MW to Effective MW Requirement, 2014
Jan	862	690	720	663	1.80	2.05	1.72	1.60
Feb	875	681	724	664	1.85	2.00	1.73	1.51
Mar	774	683	681	664	1.67	1.99	1.56	1.48

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[12]

12 See the *2013 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Market Concentration

Table 10-9 shows Herfindahl-Hirschman Index (HHI) results for the first three months of 2013 and the first three months of 2014, based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the metrics used to clear the regulation market. The average HHI of 1972 is classified as highly concentrated, but is lower than the HHI for the same period in the first three months of 2013 of 2003. For the first three months of 2014, the weighted-average HHI of RegD resources was 3901 (highly concentrated).

Table 10-9 PJM cleared regulation HHI: January through March 2013 and 2014

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Mar)	957	2003	3996
2014 (Jan-Mar)	977	1972	3813

Figure 10-5 compares the frequency distribution of HHI for the first three months of 2014 with the first three months of 2013.

Figure 10-5 PJM Regulation Market HHI distribution: January through March 2013 and 2014

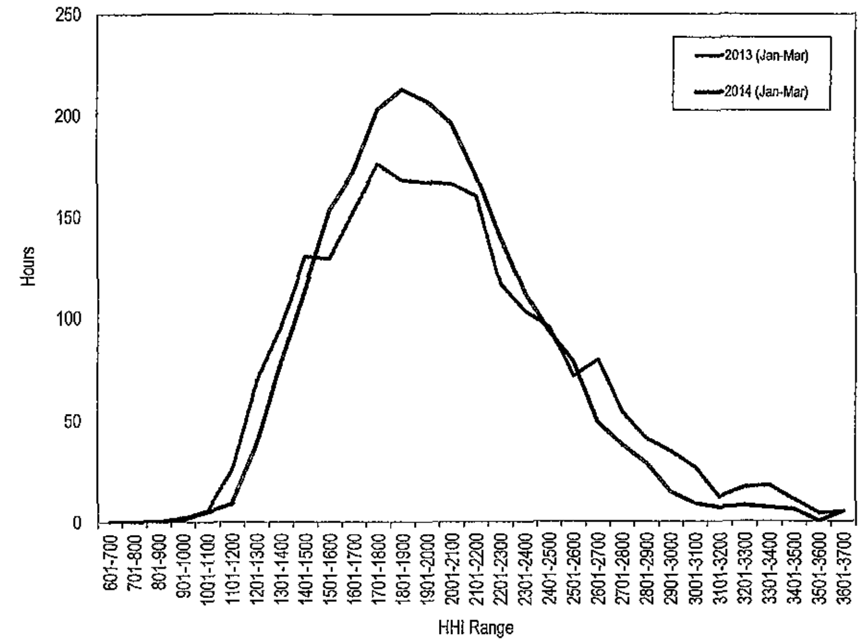


Table 10-10 includes a monthly summary of three pivotal supplier results. In the first three months of 2014, 97 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-7).

The MMU concludes from these results that the PJM Regulation Market in the first three months of 2014 was characterized by structural market power in 97 percent of hours.

Table 10-10 Regulation market monthly three pivotal supplier results: January through March 2012 through 2014

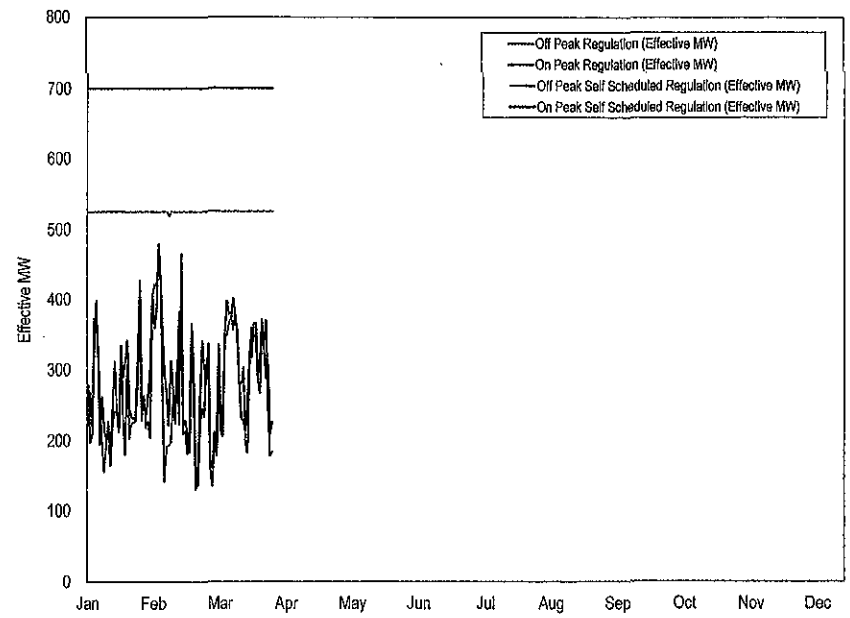
	2012	2013	2014
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	71%	83%	97%
Feb	67%	82%	99%
Mar	64%	97%	95%
Average	67%	88%	97%

Market Conduct

Offers

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-11).[13] Figure 10-6 compares average hourly regulation and self scheduled regulation during on peak and off peak hours on an effective MW basis. Self scheduled regulation during on peak and off peak hours varies from hour to hour and comprises a large portion of total effective regulation per hour (on average 40.1 percent during on peak and 51.7 percent during off peak hours in the first three months of 2014).

Figure 10-6 Off peak and on peak regulation levels: January through March 2014



Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first three months of 2014, 61.0 percent was purchased in the PJM market, 34.2 percent was self-scheduled, and 4.8 percent was purchased bilaterally (Table 10-11) From 2010 through the first three months of 2014, Table 10-12 shows the total regulation by market regulation, self-scheduled regulation, and bilateral regulation. These tables are based on settled (purchased) MW, but are not adjusted for either performance score or benefit factor to maintain consistency with January through March in years 2010 through 2012 when these constructs were not part of the Regulation Market.

13 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60, (June 1, 2013); para 4.1, pp 15.

Table 10-11 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March 2013 and 2014

Year	Month	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)	RegA Regulation (MW)	RegA Percent of Total	RegD Regulation (MW)	RegD Percent of Total
2013	Jan	413,304	83.6%	72,880	14.7%	8,070	1.6%	494,253	486,959	98.5%	7,294	1.5%
2013	Feb	338,990	74.7%	102,005	22.5%	12,808	2.8%	453,803	444,689	98.0%	9,113	2.0%
2013	Mar	275,880	60.0%	165,987	36.1%	17,554	3.8%	459,421	441,000	96.0%	18,421	4.0%
2014	Jan	259,686	63.7%	125,234	30.7%	22,737	5.6%	407,656	381,313	93.5%	26,343	6.5%
2014	Feb	217,755	59.4%	132,385	36.1%	16,530	4.5%	366,670	342,929	93.5%	23,741	6.5%
2014	Mar	245,981	59.8%	148,162	36.0%	17,524	4.3%	411,667	384,304	93.4%	27,363	6.6%

Table 10-12 Regulation sources by year: January through March, 2010 through 2014

Year (Jan-Mar)	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)
2010	1,615,233	83.8%	271,709	14.1%	41,288	2.1%	1,928,230
2011	1,503,065	78.9%	338,972	17.8%	62,330	3.3%	1,904,367
2012	1,512,255	73.5%	484,971	23.6%	61,400	3.0%	2,058,626
2013	1,028,173	73.1%	340,872	24.2%	38,432	2.7%	1,407,477
2014	723,422	61.0%	405,781	34.2%	56,790	4.8%	1,185,993

In the first three months of 2014, DR provided an average of 3.83 MW of regulation per hour. Generating units supplied an average of 684.39 MW of regulation per hour.

Market Performance

Price

The weighted average RMCP for the first three months of 2014 was $91.94 per MW. This is the average price per unadjusted capability MW. This is a 172.8 percent increase from the weighted average RMCP of $33.70/MW in first three months of 2013. Figure 10-7 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on an unadjusted regulation capability MW basis.

Figure 10-7 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

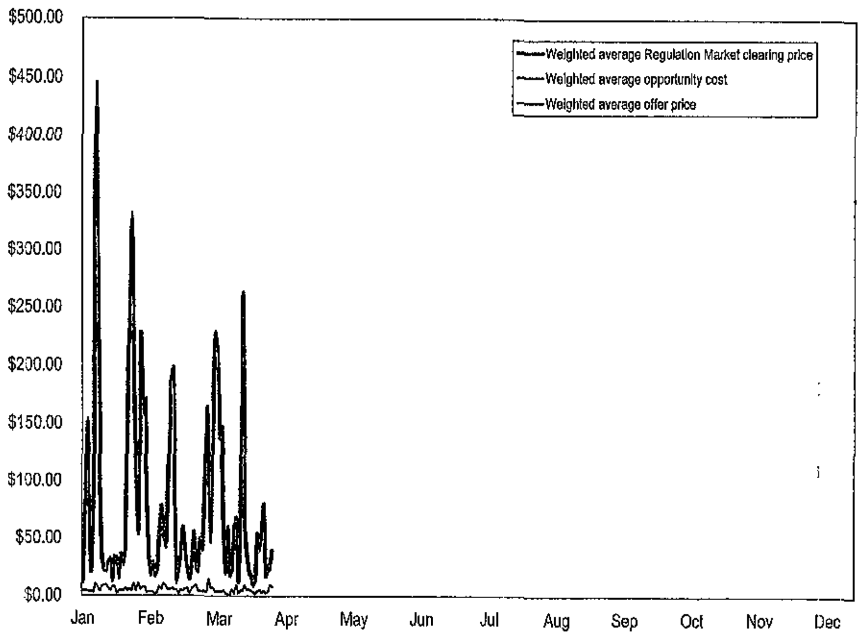


Table 10-13 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-13 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$132.49	$5.44	$101.27
Feb	$62.61	$4.72	$60.76
Mar	$80.73	$4.79	$71.35

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-14. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-14 Total regulation charges: January through March, 2013 and 2014

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($/MW)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2013	Jan	494,253	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87%
2014	Jan	407,656	$65,714,049	$132.49	$161.20	82%
2014	Feb	366,670	$27,293,638	$62.61	$74.44	84%
2014	Mar	411,667	$40,104,102	$80.73	$97.42	83%

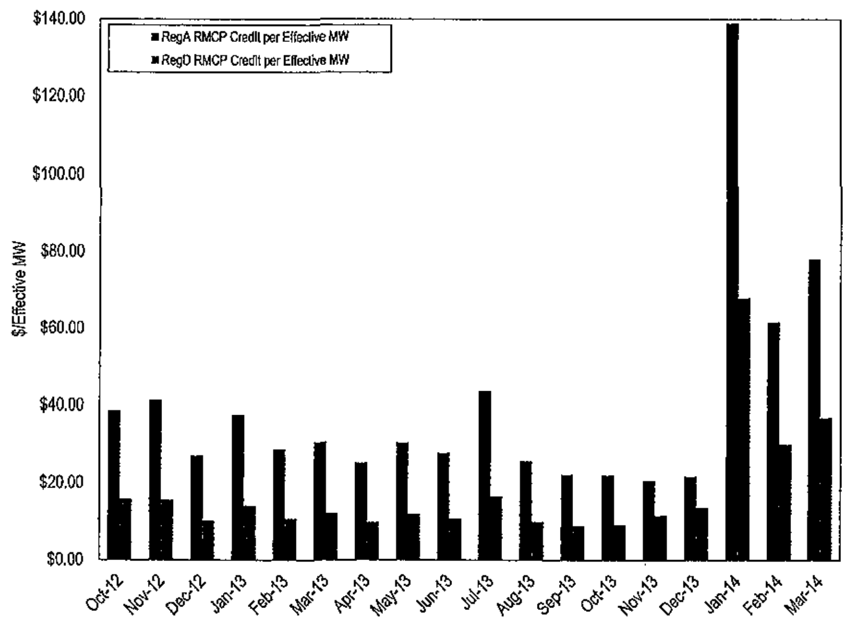
The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-15. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-15 Components of regulation cost: 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,667	$76.75	$5.71	$14.96	$97.42

A comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources from October 1, 2012, (the implementation date of the performance-based Regulation Market) through the first three months of 2014 is shown in Figure 10-8. On November 1, 2013, PJM removed the marginal benefit factor from all settlement calculations. In its place, PJM inserted the mileage ratio for the performance credit only. In Figure 10-8, the RegA RMCP Credit per effective MW is, on average, 2.6 times higher than the RegD RMCP Credit per effective MW from October 2012 through October 2013. However, since November 1, 2013, the RegA RMCP Credit per effective MW is only, on average, 1.9 times higher than the RegD RMCP Credit per effective MW. Were the marginal benefit factor correctly applied to settlements, the average RegD RMCP Credit per effective MW would be higher and equal to the RegA RMCP Credit per effective MW.

Figure 10-8 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through March 2014[14]



14 These values are credits before PJM makes its retroactive adjustments to RMCP credits.

Table 10-16 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was more in the first three months of 2014 than it was in the first three months of 2013. This is a result of extreme market conditions in January.

Table 10-16 Comparison of average price and cost for PJM Regulation, January through March, 2008 through 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,667	$76.75	$5.71	$14.96	$97.42

Primary Reserve

Reserves are sources of energy that can be made available within a defined time for the purpose of correcting an imbalance between supply and demand. Primary reserve is ten minute reserve which can be sustained for up to thirty minutes to correct a disturbance.[15,16]

PJM uses synchronized and non-synchronized reserve, both of which are available within ten minutes, to provide primary reserve. Synchronized reserve is on line and synchronized to the grid. Non-synchronized reserve may be provided by any unit not synchronized to the grid but capable of providing energy within ten minutes.

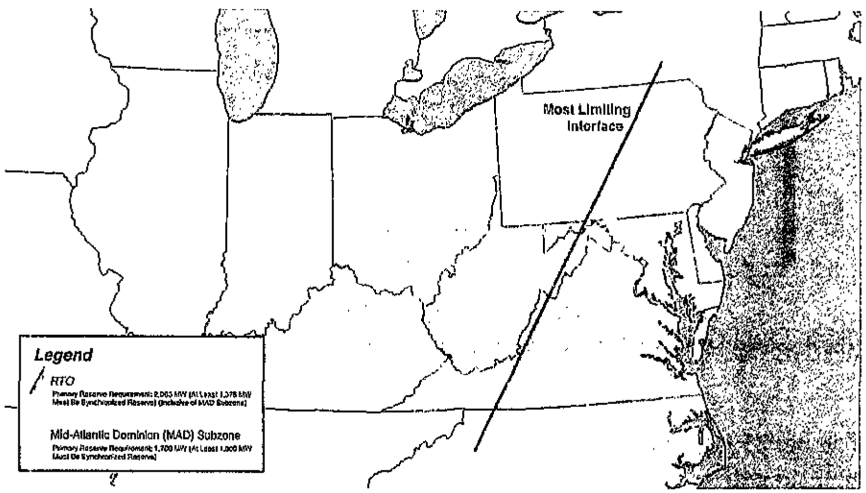
Requirements

For the RTO Reserve Zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint, currently 2,063 MW. Changes to this requirement can occur when grid maintenance or outages change the largest contingency. The actual hourly average RTO primary reserve requirement was 2,066 MW in January through March 2014 (Table 10-18).

15 NERC uses the term contingency reserves, which are reserves available within 15 minutes and that may be on line or off line. PJM criteria require response within 10 minutes. PJM meets the NERC requirements through primary reserves.
16 NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12. Balancing Operations" Revision 30. Attachment D. "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the *Mid-Atlantic Dominion (MAD)* Subzone. Of the 2,063 MW RTO primary reserve requirement, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone (Figure 10-9). The actual hourly average MAD primary reserve requirement was 1,704 MW in January through March, 2014 (Table 10-18).

Figure 10-9 PJM RTO geography and primary reserve requirement: January through June 2013



Of the 2,063 MW RTO primary reserve requirement, PJM requires that at least 1,375 MW be synchronized to the grid. The synchronized reserve requirement is 100 percent of the largest contingency. Of the 1,375 MW of synchronized reserve requirement for the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone.

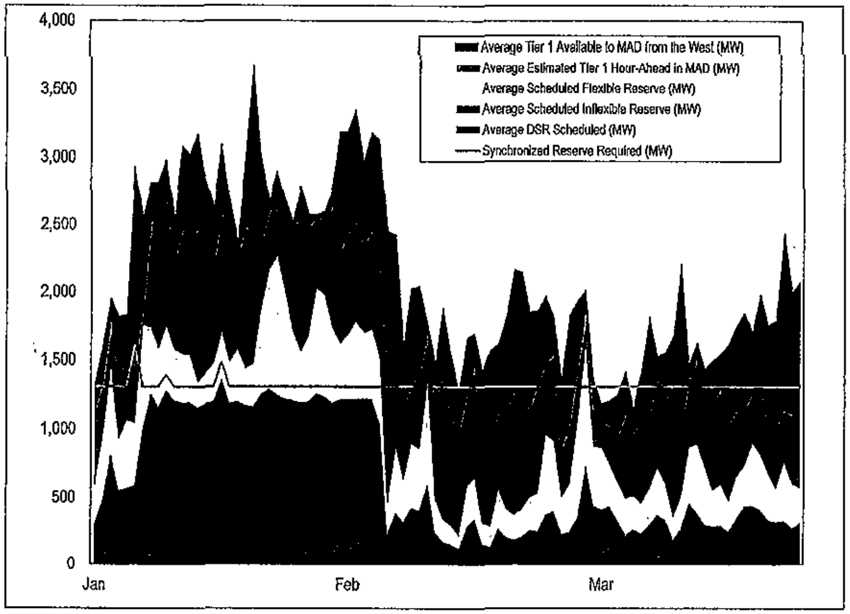
The Mid-Atlantic Dominion Reserve Subzone is defined dynamically by the most limiting constraint real time.[17] In 78.1 percent of hours in January through March 2014, that constraint was the Bedington – Black Oak transfer interface constraint (Figure 10-9).

Synchronized and non-synchronized reserve is identified, priced, and assigned by PJM's market solution software. The market solution software consists of three distinct modules: the Ancillary Services Optimizer (ASO), the intermediate term security constrained economic dispatch market solution (IT-SCED) and the real time (short term) security constrained economic dispatch market solution (RT-SCED). The ASO jointly optimizes energy, synchronized reserves, non-synchronized reserves, and regulation based on forecast system conditions to determine an economic set of inflexible reserve resources to commit for the upcoming operating hour (before the hour commitments). IT-SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT-SCED is used to estimate available tier 1 synchronized reserve and to provide a near real time load forecast and ancillary services solutions. RT-SCED runs at five minute intervals and jointly optimizes energy and reserves given inflexible unit commitment. The RT-SCED estimates the available tier 1, provides a real time ancillary services solution and can commit additional within-hour flexible tier 2 resources.

The components of the Mid-Atlantic Dominion Primary Reserve Zone primary reserve solution in order of increasing cost are: tier 1 synchronized reserve available within the Mid-Atlantic Dominion Primary Reserve Zone; tier 1 synchronized reserve available across the most limiting constraint; tier 2 before the hour commitments of inflexible demand response; tier 2 before the hour commitments of inflexible generation; and tier 2 within hour commitments of flexible generation.' Figure 10-10 shows daily average Mid-Atlantic Dominion Subzone primary reserves MW by source for the January 1, 2014, through March 31, 2014 period. Figure 10-10 shows tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements in the Mid-Atlantic Dominion (MAD) subzone.

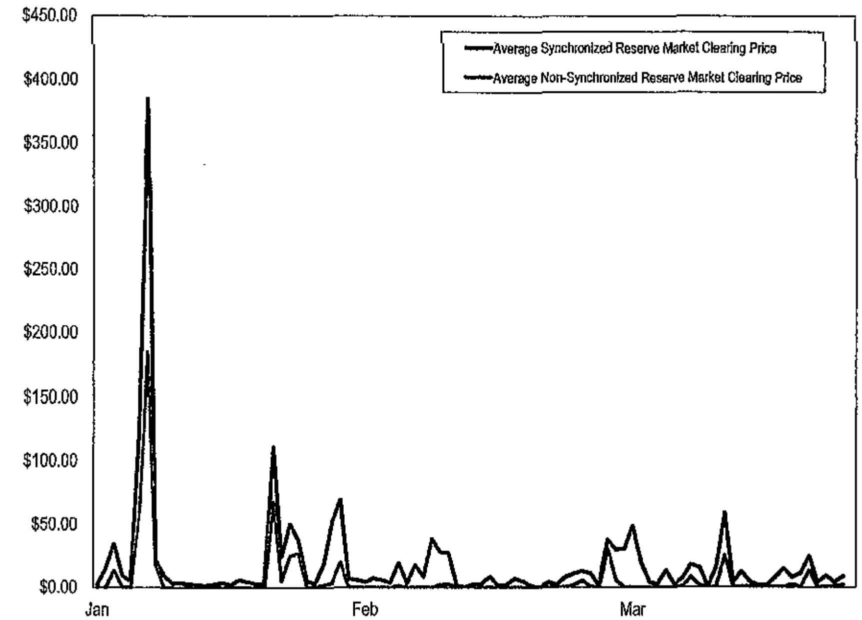
17 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 62 (January 6, 2014), p. 66.

Figure 10-10 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): January through March 2014



In January 2014, cold weather resulted in high loads which, combined with unit outages, contributed to volatility and high prices in the primary reserve (synchronized and non-synchronized) markets. Figure 10-11 shows Mid-Atlantic Dominion Subzone daily average synchronized and non-synchronized market clearing prices from January 1, 2014, through March 31, 2014.

Figure 10-11 Mid-Atlantic Dominion Subzone daily average market clearing price: January through March 2014



PJM experienced primary and synchronized reserve shortage events on January 6 and 7 of 2014.

On January 6, in response to a reserve shortage, PJM issued a Voltage Reduction Warning, followed shortly by a Voltage Reduction Action in hours 19 and 20. PJM issued RTO-wide Voltage Reduction Warnings on January 6, 7, and 30 for synchronized reserve shortages.

On January 7, PJM issued a Primary Reserve Warning indicating that the supply of primary reserve dropped below the required level. On January 7, PJM's RTO Zone experienced synchronized reserve shortages in hours 7 through 11 and Primary Reserve shortfalls in hours 7 through 12, 17 and

18. On January 7, 2014, PJM's MAD Zone experienced *synchronized reserve shortages* and primary reserve shortages in hours 7 through 12, 17 and 18.

The synchronized reserve and primary reserve shortfalls triggered Shortage Pricing in hours 7 through 12, 17 and 18.

Synchronized Reserve Market

PJM operates a Synchronized Reserve Market in the RTO Synchronized Reserve Zone. Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 1 synchronized reserve is provided by any resource that is on-line, following economic dispatch, and capable of increasing its output within ten minutes following a call for a synchronized reserve event (often called spinning event). Tier 1 resources are not required to respond to a synchronized reserve event. Market solutions provided by the ASO, IT-SCED and RT-SCED estimate the amount of tier 1 synchronized reserve available from the current energy price based economic dispatch and subtract that amount from the synchronized reserve requirement to determine how much tier 2 synchronized reserve is needed. Tier 2 synchronized reserve is provided by on-line resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point that deviates from their energy price based economic dispatch. Tier 2 synchronized reserves commitments guarantee that the Tier 2 MW will be available in the event of a synchronized reserve event. Tier 2 resources are required to provide their reserve MW within ten minutes of a synchronized reserve event.

The Synchronized Reserve Market clears Tier 2 synchronized reserve to satisfy the synchronized reserve portion of the primary reserve requirement (2,063 MW, of which 1,375 MW must be synchronized reserve) minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units synchronized to the grid.

A market also exists for the Mid-Atlantic Dominion subzone (MAD) to satisfy a constraint that of the 1,375 MW of synchronized reserve in the RTO at least 1,300 MW must be deliverable to the Mid-Atlantic Subzone.

Tier 2 synchronized reserves *can be provide by flexible or inflexible resources.* The flexibility or inflexibility of a resource is a function of the resource's operating parameters. Inflexible online resources, such as demand response (DR) or large steam units, are scheduled to provide Tier 2 synchronized reserves sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC) (demand response resources are paid SRMCP). Flexible on line resources, such as hydro resources or combustion turbines (CTs), can be assigned to Tier 2 within the operating hour as system requirements warrant.

Market Structure

Supply

With the exception of several hours on January 6 and 7, the supply of offered and eligible tier 2 synchronized reserve for January, February and March was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. On January 6, hours 19 and 20, an RTO-wide Shortage Pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below 1,375 MW synchronized reserve requirement. On January 7 deficient synchronized reserves in the RTO Reserve Zone caused Shortage Pricing in hours 7 through 11. On January 7 deficient synchronized reserves in the Mid-Atlantic Dominion Reserve Subzone caused Shortage Pricing in hours 7 through 12, 17 and 18.

Synchronized reserve is designed to provide relief for disturbances.[18] PJM dispatchers can use synchronized reserve as a source of energy to provide relief from low ACE. Such an event occurred on January 6, 2014. Three extended (68, 25, and 34 minutes) spinning events were declared during afternoon and evening hours of January 6 for low ACE.

If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line non-emergency generation capacity resources

18 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, pp 451-452.

available to provide energy must submit an offer for tier 2 synchronized reserve.[19] This rule is intended to increase the accuracy of estimates of available primary reserve.

The Tier 2 Synchronized Reserve Market for the MAD subzone cleared an hourly average 414.6 MW with a weighted average SRMCP of $26.46 in the first three months of 2014. This is an increase of $19.11 over the weighted average SRMCP of $7.35 for the first three months of 2013. The DR MW share of the total cleared MAD subzone Tier 2 Synchronized Reserve Market was 18.3 percent in the first three months of 2014.[20] This is a reduction of 30.7 percent from the DR MW share of 49 percent of all cleared MAD tier 2 synchronized reserve from the same period in 2013.

The Tier 2 Synchronized Reserve Market for the RTO Zone cleared in 56.9 percent of hours averaging 160.2 MW with a weighted average SRMCP of $50.90 for the first three months of 2014. This is an increase from the first three months of 2013 in which the Tier 2 Synchronized Reserve Market for the RTO Zone cleared in only eight hours. The increase is a result of a change in PJM's method for estimating available tier 1 MW which was effective October 1, 2013.

Between October 1, 2013 and December 31, 2013, PJM implemented several changes in the way tier 1 available MW is estimated.[21] The effect of these changes in both the RTO zone and MAD subzone was to reduce the estimates of tier 1 and to increase the amount of tier 2 MW cleared. The changes included involved capping the tier 1 estimate at the lesser of a generator's economic maximum or its spinning maximum value (spinning maximum is a parameter defined as the maximum output a unit can attain within ten minutes). In addition, hydro units were excluded from tier 1 estimates because most hydro units do not respond to Spin Events as they operate on a schedule and have limitations based on water availability and time of day. In addition, combined cycle units are excluded from tier 1 estimates because combined cycles often require additional equipment or operator intervention to respond to spinning events. In addition, units that are assigned provide regulation and units that are backed down for constraint control are excluded from tier 1 estimates. The goal was a more realistic estimated tier 1 reserve.

Demand

The default hourly-required synchronized reserve requirement is 1,375 MW and the requirement for the MAD subzone is 1,300 MW, Table 10-17.[22]

Table 10-17 Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Dec 31, 2012	1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

Exceptions to the requirement can occur when grid maintenance or outages change the largest contingency. Exceptions in the first three months of 2014 are listed in Table 10-18.

19 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 64, (January 6, 2014), p. 63.
20 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.
21 PJM Operating Committee Meeting, November 5, 2013, <http://www.pjm.com/~/media/committees-groups/committees/oc/20131105/20131105-item-10-oc-tier-1-changes.ashx>.
22 NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12: Balancing Operations" Revision 30, Attachment D, "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

Table 10-18 Exceptions to RTO Zone and MAD Subzone Synchronized Reserve requirement: *January through March 2014*

Time Period	MAD Temporary Synchronized Reserve Requirement (MW), Normally 1,300 MW	RTO Temporary Synchronized Reserve Requirement (MW), Normally 1,375 MW
Jan 6 mkt hour 19	2,025	2,093
Jan 6 mkt hour 20	7,824	7,843
Jan 10 mkt hour 5	1,341	1,409
Jan 10 mkt hours 6-9	1,786	1,786
Jan 10 mkt hour 10	1,341	1,409
Jan 17 mkt hour 6	1,381	1,444
Jan 17 mkt hours 7-14	1,786	1,786
Jan 17 mkt hour 15	1,543	1,581
Mar 17 mkt hour 17		1,394
Mar 17 mkt hours 18-23		1,600
Mar 18 mkt hour 0		1,394
Mar 18 mkt hour 4		1,394
Mar 18 mkt hours 5-22		1,600
Mar 18 mkt hour 23		1,581
Mar 19 mkt hour 5		1,581
Mar 19 mkt hour 6-14		1,600
Mar 19 mkt hour 15		1,563

The market demand for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone is determined by subtracting the amount of forecast tier 1 synchronized reserve (+/- the tier 1 estimate bias when applicable) available in the subzone including the amount of tier 1 available from the RTO Zone, from the subzone's requirement each five-minute period. Market demand is also reduced by subtracting the amount of self-scheduled tier 2 resources.

Figure 10-12 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled in the first three months of 2014, for the Mid-Atlantic Dominion Reserve Market. The month of January 2014 was unusual in that much more tier 2 synchronized reserve was cleared than prior years. As a result of the extreme weather and reserve shortages on the cold weather days, which reduced the tier 1 available, the dispatchers biased the tier 1 estimate down.

Supply and Demand

The change to the estimates of tier 1 made in the last three months of 2013 had a significant impact on the frequency of clearing an RTO Synchronized Reserve Market. In the RTO Synchronized Reserve Zone 56.9 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first three months of 2014 averaging 160.2 MW. An RTO Tier 2 Synchronized Reserve Zone Market was cleared in less than one percent of hours from January through March, 2013.

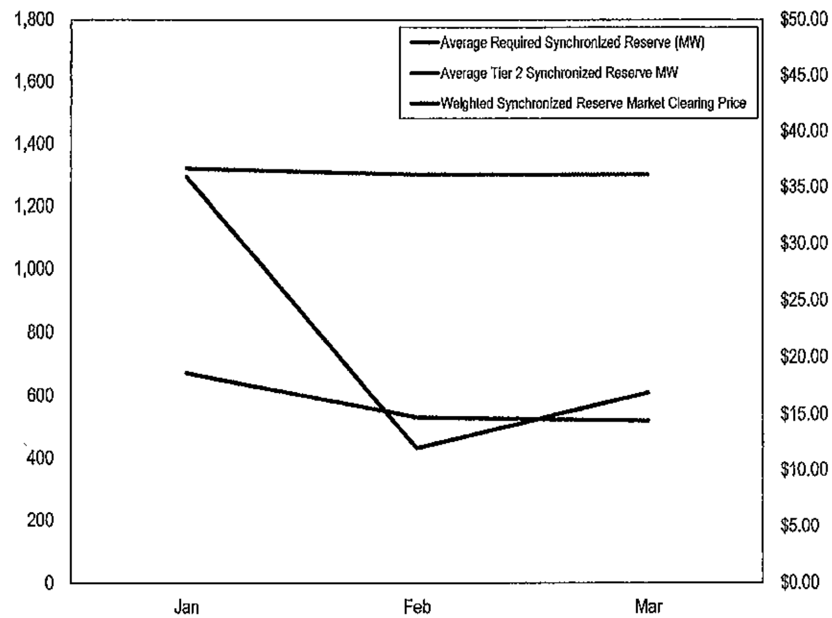
In the Mid-Atlantic Dominion Subzone, 99.8 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first three months of 2014 averaging 153.8 MW. This is a slight increase from the average of 146.7 MW cleared in the first three months of 2013.

In the first three months of 2014, the weighted average Tier 2 Synchronized Reserve Market Clearing Price in the RTO Zone for all cleared hours was $50.90. In the first three months of 2013 the weighted average Synchronized Reserve Market Clearing Price in the RTO Zone (only cleared eight hours) was $0.64. In the first three months of 2014, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $26.46. In the first three months of 2013 the weighted average Synchronized Reserve Market Clearing Price in the MAD subzone was $7.35.

Shortage pricing for synchronized reserve was triggered on January 6 and 7. On January 6, hours 19 and 20, an RTO-wide Shortage Pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below 1,375 MW synchronized reserve requirement. On January 7 deficient synchronized reserves in the RTO Reserve Zone caused Shortage Pricing in hours 7 through 11. On January 7 deficient synchronized reserves in the Mid-Atlantic Dominion Reserve Subzone caused Shortage Pricing in hours 7 through 12, 17 and 18.

Both the RTO Zone and the MAD subzone experienced a primary reserve shortage and resulting Shortage Pricing event on January 6 in hour 19 and 20 and on January 7 in hours 7 through 12, 17 and 18.

Figure 10-12 Mid-Atlantic Dominion Reserve Subzone Monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January through March 2014



Market Concentration

The HHI for settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market for the first three months of 2014 was 4236, which is defined as highly concentrated. The HHI for the first three months of 2013 for the Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market was 2638, which is also defined as highly concentrated. The largest hourly market share was 100 percent and 56 percent of all hours had a maximum market share greater than or equal to 40 percent, higher than the 35 percent for the first three months of 2013. Most Tier 2 synchronized reserve is provided by inflexible scheduled resources.[23] Flexible synchronized reserve assigned was 14.0 percent of all tier 2 synchronized reserve in the MAD subzone in the first three months of 2014. Flexible synchronized reserve assigned was 24.5 percent of all tier 2 synchronized reserve in the RTO zone in the first three months of 2014. The hourly average HHI in the first three months of 2014 in the MAD subzone was 8743 for flexible resources assigned during the hour. The hourly average HHI in the first three months of 2014 in the RTO zone was 9078 for flexible resources assigned during the hour.

The MMU calculates that 57.9 percent of hours failed the three pivotal supplier test in the MAD subzone in the first three months of 2014 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-19) and 37.7 percent of hours would have failed a three pivotal supplier test in the RTO zone in the first three months of 2014.

Table 10-19 Three Pivotal Supplier Test Results for the RTO Zone and MAD Subzone: January through March, 2014

Year	Month	MAD Subzone Percent of Hours Pivotal	RTO Zone Percent of Hours Pivotal
2014	Jan	91.2%	74.0%
2014	Feb	46.1%	22.0%
2014	Mar	36.4%	17.0%
2014	Average	57.9%	37.7%

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

23 See the *2013 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT-SCED runs.

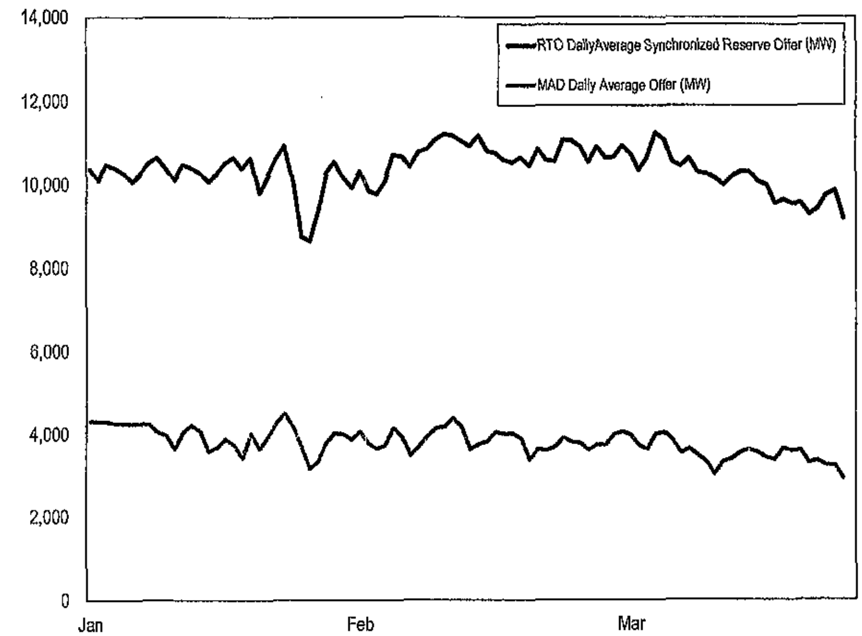
Market Behavior

Offers

Daily cost based offer prices are submitted for each unit by the unit owner. For generators the offer price must include tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer includes the synchronized reserve offer quantity (MW). The offer quantity is limited to the economic maximum or less if a spin maximum value less than economic maximum is supplied. PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times ten minutes. Figure 10-13 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In the first three months of 2014, the ratio of on-line tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 3.02 averaged over all hours. The highest offered to required ratio was 3.99 on January 31 and the lowest was 1.77 on March 31. For the RTO Synchronized Reserve Zone the ratio was 8.85. The highest offered to required ratio was 10.46 on January 1 and the lowest was 6.62 on March 27.

After October 1, 2012, PJM adopted a new rule creating a must offer requirement for synchronized reserve for all generation that is online, non-emergency, and available to produce energy. Compliance with this rule has improved in the first three months of 2014, but remains incomplete. As of March 31, 2014, 24.0 percent of eligible resources do not comply with this requirement.

Figure 10-13 Tier 2 synchronized reserve daily average offer volume (MW): January through March 2014



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. Figure 10-14 shows average offer MW volume by market and unit type for the MAD subzone and Figure 10-15 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-14 Mid-Atlantic Dominion Subzone average daily tier 2 synchronized reserve offer by unit type (MW): January through March 2012 – 2014

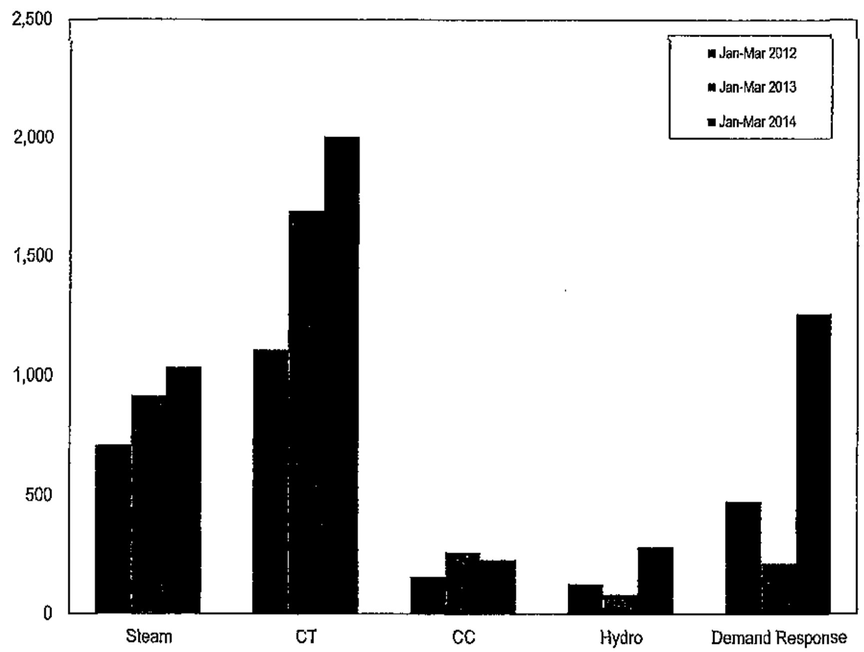
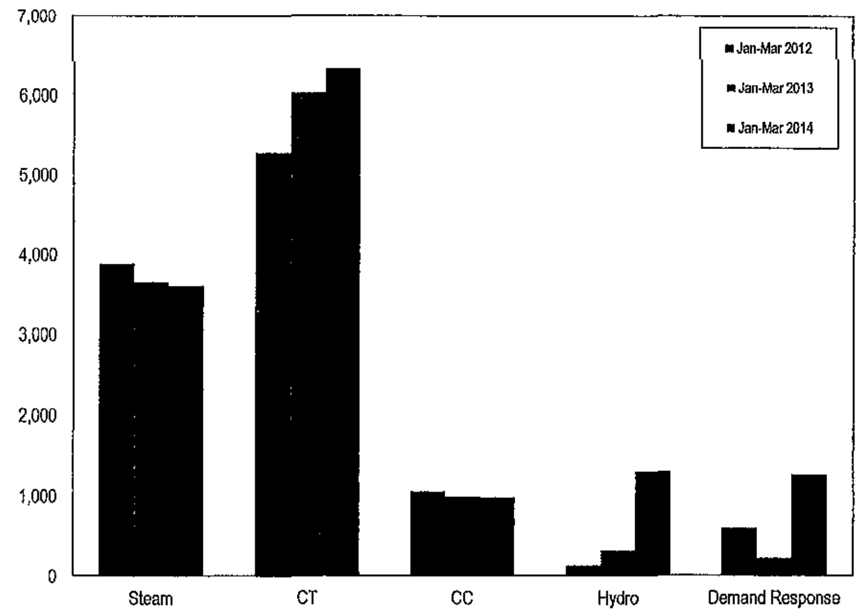


Figure 10-15 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through March 2012 – 2014



Demand Resources

Demand resources remain a significant part of market scheduled synchronized reserve although their share of total cleared synchronized reserve declined significantly as the amount of tier 2 has increased. In the first three months of 2014, DR was 17.7 percent of all cleared Tier 2 synchronized reserves, compared to 51.7 percent for the first three months of 2013.

Market Performance

Price

Table 10-20 shows all tier 2 credits including LOC credits, all tier 1 credits including credits paid to tier 1 resources when the Non Synchronized Reserve Market Clearing Price is above $0, all tier 2 MW including MW scheduled by PJM, self scheduled, and added by either the intermediate or short term market solution software for the Mid-Atlantic Dominion subzone.

Table 10-20 RTO Zone, Mid-Atlantic Dominion Subzone, and Full RTO credits, and MWs: January through March 2014

Synchronized Reserve Market	Year	Month	Tier 2 Synchronized Reserve Credits	Tier 1 Synchronized Reserve Credits	Tier 2 Synchronized Reserve Cleared MW	Tier 2 Synchronized Reserve Added By SCED MW	Self Scheduled Tier 2 Synchronized Reserve MW	Total Tier 2 Synchronized Reserve MW
RTO Zone w/o MAD Subzone	2014	Jan	$6,099,636	$21,685,392	16,629	3,557	0	20,185
RTO Zone w/o MAD Subzone	2014	Feb	$1,503,069	$850,597	19,456	4,647	0	24,103
RTO Zone w/o MAD Subzone	2014	Mar	$1,694,304	$2,887,014	33,646	14,551	0	48,196
MAD Subzone	2014	Jan	$19,392,761	$44,252,473	253,282	35,604	147,561	436,448
MAD Subzone	2014	Feb	$4,695,064	$1,759,180	118,287	28,536	124,119	270,942
MAD Subzone	2014	Mar	$10,298,554	$7,985,276	119,112	79,383	121,659	320,154
All RTO	2014	Jan	$25,492,397	$65,937,864	269,911	39,161	147,561	456,633
All RTO	2014	Feb	$6,198,133	$2,609,777	137,743	33,183	124,119	295,045
All RTO	2014	Mar	$11,994,837	$10,872,290	152,757	93,934	121,659	368,350

Table 10-21 RTO Zone, Mid-Atlantic Dominion Subzone, and Full RTO Weighted SRMCP, Tier 2 Cost, and Synchronized Reserve Cost

Synchronized Reserve Market	Year	Month	Weighted Synchronized Reserve Market Clearing Price ($/MW)	Tier 2 Cost ($/MW)	Synchronized Reserve (Tier 1 plus Tier 2) Cost ($/MW)
RTO Zone w/o MAD Subzone	2014	Jan	$145.25	$302.18	$1,376.48
RTO Zone w/o MAD Subzone	2014	Feb	$31.95	$62.36	$97.65
RTO Zone w/o MAD Subzone	2014	Mar	$20.86	$35.15	$95.06
MAD Subzone	2014	Jan	$40.02	$44.43	$145.83
MAD Subzone	2014	Feb	$12.65	$17.33	$23.82
MAD Subzone	2014	Mar	$19.66	$32.21	$57.21
All RTO	2014	Jan	$44.67	$55.83	$200.23
All RTO	2014	Feb	$14.23	$21.01	$29.85
All RTO	2014	Mar	$19.81	$32.59	$62.18

The Tier 1 synchronized reserve compensation rules included in PJM's shortage pricing filing resulted in a substantial increase in payments for the same service. Under the rule change, Tier 1 is paid more when the non-synchronized reserve price rises above zero. PJM's shortage pricing rules require that tier 1 synchronized reserve be paid the tier 2 synchronized reserve clearing price when the non-synchronized reserve clearing price is above $0. This rule significantly increases the cost of tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not reserving any tier 1, but simply paying substantially more for the same product without any additional performance requirements. The impact of the change to the way tier 1 estimate is calculated had a significant effect on the tier 2 market. The significance of this rule can be seen in Table 10-20.

The MAD subzone cleared a tier 2 synchronized reserve market in 99.4 percent of hours in the first three months of 2014 compared to 38 percent of hours in January through March, 2013. The RTO Zone cleared a tier 2 synchronized reserve market in 56.9 percent of hours in January through March of 2014 compared to less than one percent of hours in January through March, 2013.

For the first three months of 2014, the weighted average price for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was $26.46 while the cost of tier 2 synchronized reserve was $33.48. The price for synchronized reserve in the first three months of 2013 was $7.35 while the cost was $12.58.

For the first three months of 2014 (Table 10-21), the weighted average price for tier 2 synchronized reserve in the RTO reserve zone (exclusive of the MAD subzone) was $50.90 while the cost of tier 2 synchronized reserve was $100.53.

Although the market is separated into a zone and subzone with different requirements and often different clearing prices, it is useful to look at the weighted price and cost of the PJM RTO in its entirety. For the RTO and MAD together, the weighted average SRMCP was $44.67 for the first three months of 2014, the tier 2 cost was $28.48 and the cost of tier 2 synchronized reserve was $39.02.

There is no market for tier 1 synchronized reserve so there is no clearing price for it but it is paid when it performs. With shortage pricing tier 1 is paid the tier 2 SRMCP whenever the non-synchronized reserve clearing price is greater than $0. By adding the total credits paid to tier 1 resources into the existing weighted calculation of tier 2 cost, the overall cost for synchronized reserve in the MAD subzone is $86.07 per MW. The overall cost of synchronized reserve in the RTO excluding the MAD subzone is $375.41 per MW. The overall cost of synchronized reserve across the entire RTO zone is $109.98 per MW.

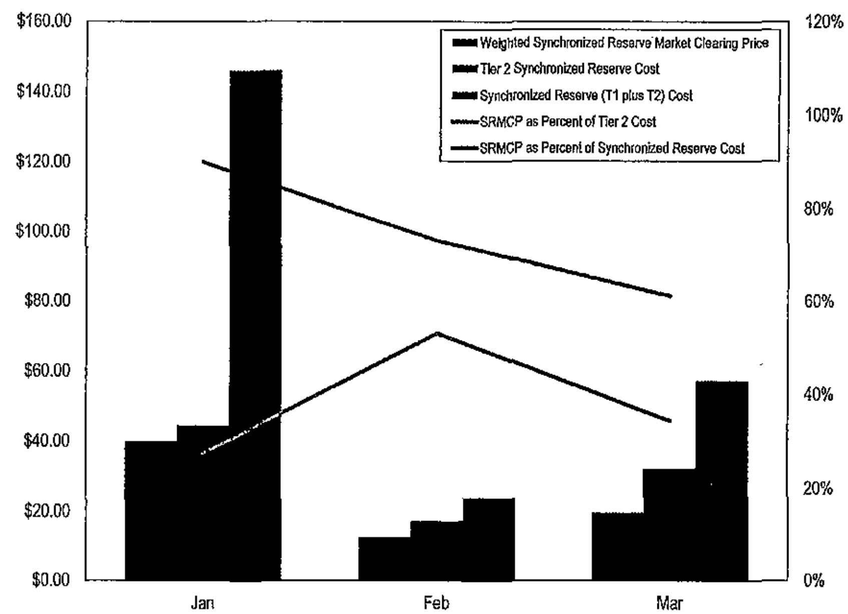
In the first three months of 2014, the non synchronized reserve market cleared above $0 in eleven percent of hours, almost all of them in January during the cold days of January 6, 7, 8, 22, 23, 24, and 25. In January 2014 PJM paid almost $66M for tier 1 synchronized reserve, only 22 percent of which was paid for tier 1 response to a spinning event. In fifteen hours during the first three months of 2014, PJM paid more than $1M each hour for tier 1 synchronized reserve (all of them on January 7, an extreme cold day) with the highest being $2.6M in hour 16. In four additional hours (on January 23, January 30, and March 4) tier 1 synchronized reserve cost over $900,000. The tier 1 payments during January 2014 were extreme because a shortage of reserve during the cold days necessitated the clearing of a non-synchronized reserve market. But even in the more normal months of February and March, tier 1 payments, when added to the cost of tier 2 made synchronized reserve significantly more expensive than it would be without the shortage pricing rule (Table 10-17). And for this additional expense PJM gets no additional response. This is a windfall payment to Tier 1 reserves.

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient synchronized reserve market design. In the Mid-Atlantic Dominion Subzone tier 2 Synchronized Reserve Market for the first three months of 2014, the price of tier 2 synchronized reserves was 79 percent of the cost. In the first three months of 2013, the tier 2 price to cost ratio was 60 percent. The highest (best) ratio occurred in the high price / high cost month of January (Figure 10-16). The price of tier 2 synchronized reserves against the full cost of synchronized reserve however (tier 1 plus tier 2) was lowest (worst) in January. For the first three months of 2014 the price of tier 2 synchronized reserve was only 38 percent of the cost of all synchronized reserve.

Figure 10-16 Comparison of Mid-Atlantic Dominion Subzone synchronized reserve weighted average clearing price and cost (Dollars per MW): January through March 2014



Tier 1 Estimate Bias

The ASO, IT-SCED and RT-SCED market clearing engines can each have its own tier 1 estimate biased. Biasing means modifying (increasing or decreasing) the demand for tier 1 synchronized reserve from the default level defined by the tariff. Negative tier 1 estimate biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much tier 2 MW to schedule. A negative bias reduces the amount of tier 1 estimated to be available and therefore increases the amount of tier 2 which must be purchased. When the hour ahead market solution (using the ASO) has its tier 1 estimate biased negatively, it forces the hour ahead market solution to include more inflexible synchronized reserve resources reducing the flexibility of the market software to reallocate an on-line resource from reserves to energy. When the IT-SCED is biased negatively it induces the within-hour market solution to move flexible resources into reserve from energy. Tier 1 estimate biasing can be used by PJM dispatchers to compensate for uncertainty in short term load forecasting, generator performance, or uncertainty in the accuracy of the tier 1 estimate of the market solution.

PJM used tier 1 estimate biasing in both the MAD and RTO synchronized reserve hour ahead market solutions during the first three months of 2014. In the MAD subzone the tier 1 estimate in the hour ahead solution was biased in 93 hours (4.3 percent) during the first three months of 2013. In the MAD subzone the tier 1 estimate in the hour ahead solution was biased in 599 hours (27.7 percent) during the first three months of 2013. In seven hours tier 1 was biased positively and in 86 hours the tier 1 bias was negative.

PJM used tier 1 estimate biasing in 328 real time market solution 5 minute periods 1.2 percent of all real time market solutions in the MAD subzone. All 328 periods were in the cold days of January 7, and 8.

The MMU recommends that PJM be more explicit about why tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for biasing.

Compliance

Synchronized reserve non-compliance has two components: failure to deliver scheduled tier 2 Synchronized Reserve MW during spinning events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during spinning events since 2011.[24] When synchronized reserve resources clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has reported a wide range of spinning event response levels and recommended PJM take action to increase compliance rates. An enhanced penalty structure became effective January 1, 2014. Penalties can be assessed for any spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In the first three months of 2014, nine spinning events occurred in the Mid Atlantic subzone that met these criteria.

24 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 260.

Table 10-22 Synchronized reserve events greater than 10 minutes, Mid-Atlantic Dominion Tier 2 Response Compliance January through March 2014

2014 Qualifying Spinning Events (DD-MON-YYYY HR)	Event Duration (minutes)	MAD Synchronized Reserve Market Clearing Price	Tier 2 Plus DR Cleared MW	Tier 2 Plus DR Added MW	Percent of Tier 2 Penalized for Non Compliance	Percent of DR Penalized for Non Compliance	Overall Percent of Synchronized Reserve Penalized for Non Compliance
06-JAN-2014 22	68	$388.20	$454.00	$0.00	26%	77%	39%
07-JAN-2014 02	25	$97.52	$539.00	$0.00	60%	79%	64%
07-JAN-2014 04	34	$193.16	$823.00	$0.00	89%	90%	89%
07-JAN-2014 11	11	$635.15	484	39	67%	11%	54%
07-JAN-2014 13	41	$800.00	$328.00	$0.00	94%	17%	64%
10-JAN-2014 16	12	$4.79	$396.00	$0.00	2%	7%	4%
31-JAN-2014 15	13	$52.74	$382.00	$53.00	14%	21%	15%
01-MAR-2014 05	26	$26.33	36	0	0%	5%	1%
27-MAR-2014 10	56	$117.37	$249.00	$309.00	43%	28%	39%

For the nine qualifying spinning events that occurred in the first three months of 2014, 50.2 percent of all scheduled synchronized reserve MW were not delivered and were penalized.

The new penalty structure will increase the number of consecutive days that an underperforming resource is penalized from three days to the lesser of the average number of days between spinning events (recalculated annually) or the numbers of days since the resource was last penalized. The average number of days between spinning events calculated for 2014 is 15 days. In addition, a resource will be penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the spinning event.[25] Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit for the purpose of reducing an underresponse penalty.

A second compliance issue is the failure to comply with the must offer requirement. The shortage pricing rules include a must offer requirement for Tier 2 synchronized for most generators under normal conditions, and an expanded set of generators under defined conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and *they must have a tier 2 offer and be available for reserve.* When PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all other non-emergency, off-line available generation capacity resources must have a tier 2 offer and be available for reserve. As of March 31, 2014, the MMU estimates that 24.0 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

PJM is to monitor every generator subject to the must-offer requirement to ensure that it has submitted a tier 2 synchronized reserve offer greater than or equal to ninety percent of its ramp rate time 10 minutes. If the offer is less than that rate, PJM will contact the generation owner.[26]

History of Spinning Events

Spinning events (Table 10-23) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[27] PJM also calls spinning events for non-disturbance events, which it characterizes as low ACE. The reserve remains loaded until system balance is recovered. From 2011 through the first three months of 2014, PJM experienced 95 spinning events, between two and three events per month. Spinning events had an average length of 13.2 minutes.

25 See PJM "M-28 Operating Agreement Accounting," Rev. 63, December 19, 2013, p. 43. See also PJM "Energy & Ancillary Services Market Operations," rev. 65, January 21, 2014, pg. 74.

26 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 65, January 21, 2014 Section 4, p. 63.

27 See PJM, "Manual 12, Balancing Operations," Revision 30 (December 1, 2013), pp. 36-37.

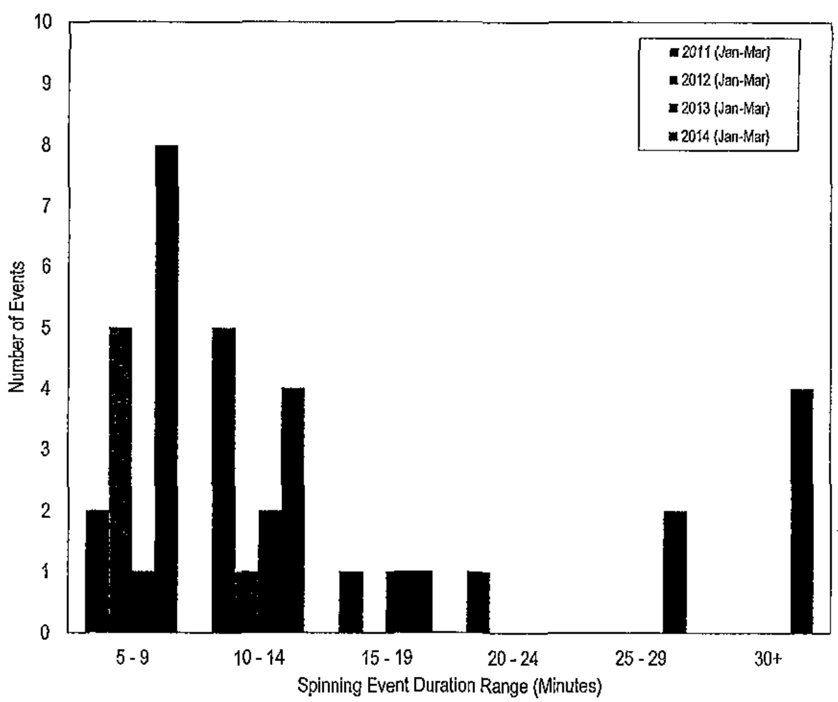
Table 10-23 Spinning events: 2011 through 2014

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:31	RTO	11	JAN-07-2014 13:20	RTO	41
FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	RTO	8
MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	RTO	18
MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12						
JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9						
JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7						
JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5						
JUL-10-2011 11:20	RFC	10									
JUL-28-2011 18:49	RFC	12									
AUG-02-2011 01:08	RFC	6									
AUG-18-2011 06:45	Mid-Atlantic	6									
AUG-19-2011 14:49	RFC	5									
AUG-23-2011 17:52	RFC	7									
SEP-24-2011 15:48	RFC	8									
SEP-27-2011 14:20	RFC	7									
SEP-27-2011 16:47	RFC	9									
OCT-30-2011 22:39	Mid-Atlantic	10									
DEC-15-2011 14:35	Mid-Atlantic	8									

Of the nineteen distinct spinning events in the first three months of 2014, ten were caused by unit trips and two were listed by PJM dispatch as being caused by Low ACE, in which synchronized reserve is being used as energy to maintain power balance.

The danger of using synchronized reserves for energy is that it reduces the amount of synchronized reserve available for a disturbance. This is always a judgment call by PJM Dispatch whose primary focus must be grid reliability. The spinning event of January 6, 2014 (caused by a unit trip) was 68 minutes which is as long as the September 10 due to low ACE. Compliance by tier 2 synchronized reserve to the 68 minute spinning event of January 6 was very poor (Table 10-22) at 39 percent.

Figure 10-17 Spinning events duration distribution curve, January through March 2011 through 2014



Non-Synchronized Reserve Market

Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. There is no defined, hourly requirement for non-synchronized reserves. It is available to meet the primary reserve requirement subject to conditions. Generation resources that have designated their entire output as emergency will not be considered eligible to provide non-synchronized reserves. Generation resources that are not available to provide energy will not be considered eligible to provide non-synchronized reserves.

PJM specifies that 1,700 MW of 10-minute primary reserve must be available in the Mid-Atlantic Dominion Reserve Sub Zone of which 1,300 MW must be synchronized reserve, and that 2,063 MW of 10-minute primary reserve must be available in the RTO Reserve Zone of which 1,375 MW must be synchronized reserve. The balance of primary reserve can be made up by the most economic combination of synchronized and non-synchronized reserve. Examples of equipment that generally qualify as non-synchronized reserve in this category are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[28]

In the MAD subzone hour ahead market solution the first 1,300 MW of the 1,700 MW primary reserve requirement must be satisfied by a jointly optimized mixture of tier 1 and tier 2 synchronized reserve. The next 400 MW of primary reserve is a jointly optimized solution of tier 1 and tier 2 synchronized reserve and non-synchronized reserve. Prices are determined during the operating hour. Sometimes a non-synchronized reserve resource becomes economic during the hour. In that case a non-synchronized reserve clearing price is established consisting of the lost opportunity cost. CTs provided 70.2 percent and hydro 26.7 percent of cleared non-synchronized reserve MW in the first three months of 2014. The remaining cleared non-synchronized reserve was provided by diesel and landfill resources.

Startup time for non-synchronized reserve resources is not subject to testing. There is no non-synchronized reserve offer MW or offer price. Prices are determined solely by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. Since non-synchronized reserve is a lower quality product its clearing price is always less than or equal to the synchronized reserve market clearing price. In most hours the non-synchronized reserve clearing price is zero.

Figure 10-18 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the MAD subzone. The

28 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 64 (January 6, 2014), p. 77.

MAD subzone non-synchronized reserve market had a clearing price greater than zero in 237 (10.5 percent) hours in the first three months of 2014, at an average price of $52.78 per MW. The weighted non-synchronized reserve market clearing price for all hours in the MAD subzone, including cleared hours when the price was zero, was $4.56 per MW. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 per MW for four consecutive hours on January 7, 2014.

Figure 10-19 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone cleared in 128 (5.9 percent) hours in the first three months of 2014 at an average price of $53.14. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone was $2.02. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 for four consecutive hours on January 7, 2014.

Figure 10-18 Daily average MAD Subzone Non-Synchronized Reserve Market clearing price and MW purchased: January through March 2014

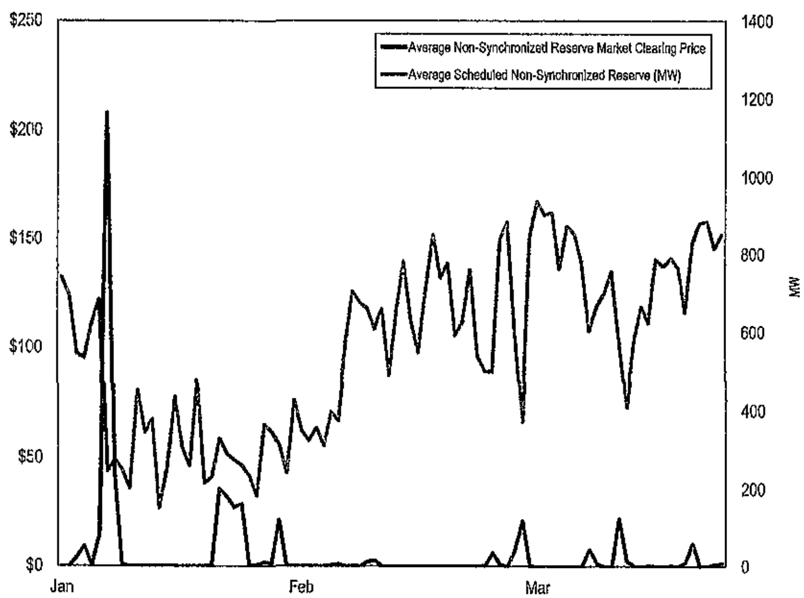
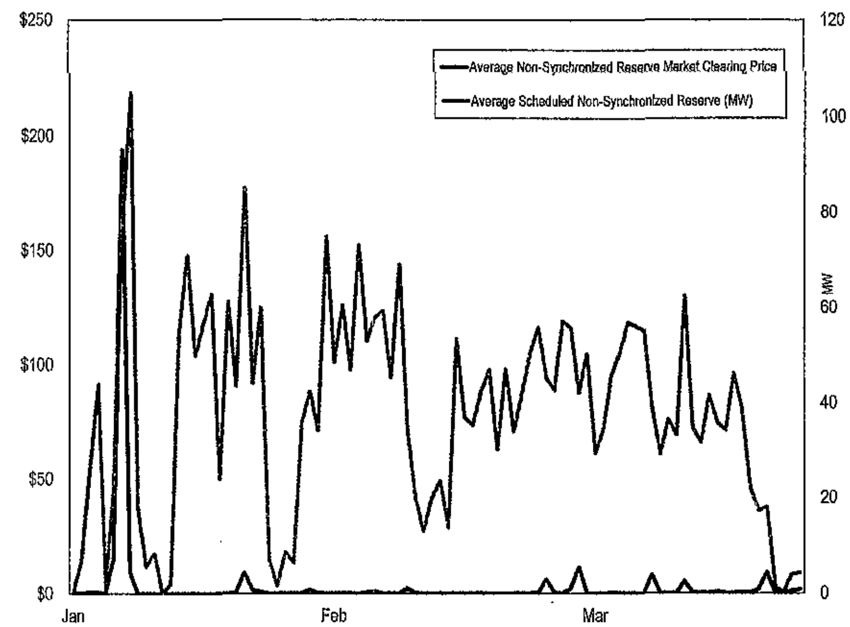


Figure 10-19 Daily average RTO Zone Non-Synchronized Reserve Market clearing price and MW purchased: January through March 2014



Day-Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves.[29] Thirty minute reserves are secondary reserves.[30]

The DASR 30-minute reserve requirements are determined by PJM for each reliability region.[31] In the Reliability*First* (RFC) region secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[32] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percentage of the daily peak load forecast. The DASR requirement

29 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
30 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.
31 See PJM. "Manual 13, Emergency Requirements," Revision 55 (January 1, 2014), p. 11.
32 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 29 (November 1, 2013), pp. 19-20.

is procured via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In the first three months of 2014, the required DASR was 6.27 percent of peak load forecast, down from 6.91 percent in 2013.[33] The DASR requirement is a sum of the load forecast error and the forced outage rate. The load forecast error is a three year average of underforecast errors. The load forecast error decreased from 2.13 percent in 2013 to 2.11 percent in 2014. The forced outrage rate is based on a three year rolling average of outages that occur between 18:00 on the scheduling day (day-ahead) and 20:00 of the operating day. The forced outage rate decreased from 4.66 percent in 2013 to 4.16 percent in 2014. The DASR MW purchased averaged 6,805 MW per hour for the first three months of 2014, a slight decrease from 6,841 MW per hour in the first three months of 2013.

In the first three months of 2014, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test in the first three months of 2013.

All generation resources are required to offer DASR.[34] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. No demand resources offered in the DASR market in the first three months of 2014. The amount of DASR available is the lesser of the energy ramp rate times thirty minutes, or the emergency maximum minus the day-ahead dispatch point. For off-line resources capable of being online in thirty minutes, the DASR quantity is emergency maximum.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[35] Units that do not offer have their offers set to $0.00 per MW.

33 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
34 See PJM "Manual 11" Revision 64, (January 6, 2014) p. 138 at Day-ahead Scheduling Reserves Market Rules.
35 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 63 (January 6, 2014), p. 143.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On March 31, 2014, 56.4 percent of resources offered at $0, 65.9 percent of resources offered at $0.05 or less, 74.4 percent of resources offered at less than $1.00. 11.5 percent resources offered DASR at levels above $5 per MW.

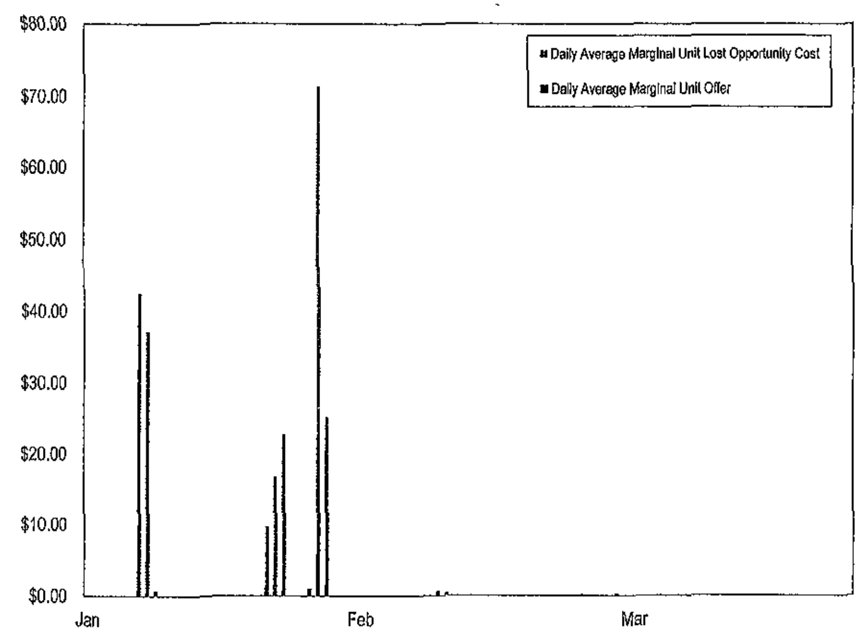
Market Performance

For 84.0 percent of hours in the first three months of 2014, DASR cleared at a price of $0.00 (Figure 10-20). For the first three months of 2014, the weighted average DASR price was $0.06. The highest DASR price was $534.66 on January 8, 2014. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of the offer price. When the DASR clearing price is greater than $0.00, 78 percent of the time the price consists solely of the offer price.

Table 10-24 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January 2012 Through March 2014

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	4,454,997	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	4,584,792	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	5,179,876	$5,975
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2013	Oct	6,077	$0.00	$0.05	$0.00	4,497,258	$2,363
2013	Nov	6,479	$0.00	$0.10	$0.00	4,665,156	$5,123
2013	Dec	7,033	$0.00	$0.80	$0.01	5,232,625	$25,192
2014	Jan	7,053	$0.00	$534.66	$8.43	5,212,272	$35,349,969
2014	Feb	6,759	$0.00	$5.00	$0.05	4,541,860	$188,762
2014	Mar	6,247	$0.00	$3.00	$0.01	4,647,607	$47,924

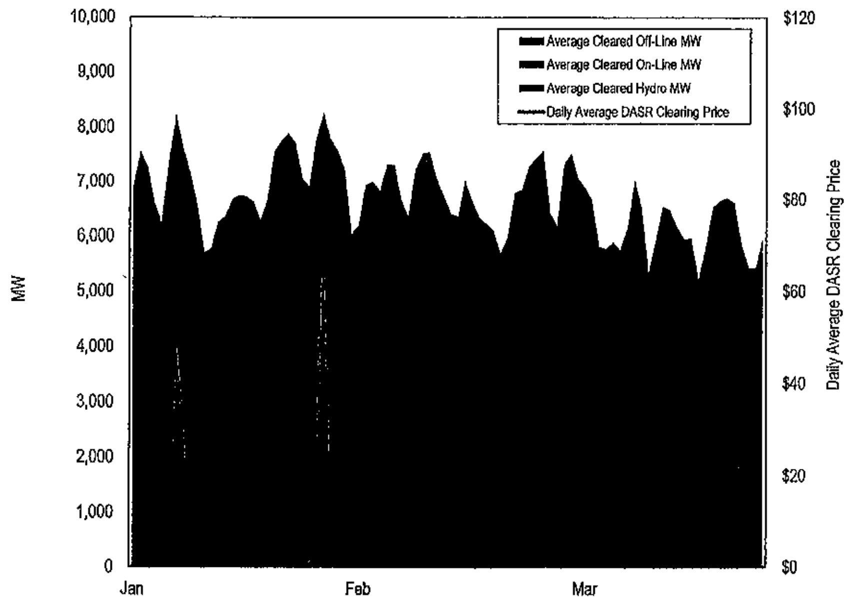
Figure 10-20 Daily average components of DASR clearing price, marginal unit offer and LOC: January through March 2014



The secondary reserve requirement is satisfied by the DASR market at $0.00 in 84 percent of hours. When energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-20 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement.

Figure 10-21 illustrates the sensitivity of DASR prices to high energy dispatch and the resource types (on-line, off-line, and hydro) used for secondary reserve. DASR prices remain very low even at high energy dispatch levels. DASR prices increase very suddenly at peak loads driven by high LOCs (Figure 10-20).

Figure 10-21 Daily average DASR prices and MW by classification: January through March, 2014



On September 10, 2013, a 68-minute spinning event was declared as a result of low ACE. On January 6, 2014 another 68-minute spinning event was declared, this time as the result of a unit trip. Different classes of reserve exist for different classes of imbalance. A 68-minute inability to bring ACE into balance with or without a sudden generator outage is the type of imbalance that 30-minute secondary reserve was created to recover from. On January 6, 2014 the average required DASR was 7,162 MW. On September 10, 2013, the 30-minute reserve requirement was 8,893 MW. Those required amounts of DASR were cleared day-ahead.

It is not clear why secondary reserve (DASR) was either unavailable to the dispatchers or was never called on the operating day when it was apparently needed. PJM dispatch called on tier 1, tier 2, and non-synchronized reserve and was unable to restore balance for 68 minutes. It is not clear why the secondary reserve, already paid for, was not called or not callable.

The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, and January 6, 2014, and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.

Black Start Service

Black start service is necessary to ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners. Substantial rule changes to the black start restoration and procurement strategy were implemented on February 28, 2013, following a stakeholder process in the System Restoration Strategy Task Force (SRSTF) and the Markets and Reliability Committee (MRC) that approved the PJM and MMU joint proposal for system restoration. These changes give PJM substantial flexibility in procuring black start resources and make PJM responsible for black start resource selection.

On July 1, 2013, PJM initiated its first RTO-wide request for proposals (RFP) under the new rules.[36] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black start by April 1, 2015. PJM identified zones with black start shortages, prioritized its selection process accordingly, and began awarding proposals on January

36 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

14, 2014. (The selection process will be completed in the first half of 2014.) PJM and the MMU have coordinated closely during the selection process.

Black start payments are non-transparent payments made to units by load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends that the current confidentiality rules be revised to allow disclosure of information regarding black start resources and their associated payments.

Total black start charges is the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on incremental black start equipment capital costs. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Total black start charges are allocated monthly to PJM customers proportionally to their zone and non-zone peak transmission use and point to point transmission reservations.

In the first three months of 2014, total black start charges were $12.7 million, a $15.0 million (54.2 percent) decrease from the January through March 2013 level of $27.6 million. Operating reserve charges declined from $22.2 million in the first three months of 2013 to $7.6 million in the first three months of 2014. This decrease was due to higher LMPs that caused more ALR black start units to run economically rather than out of merit.($21.0 million in January through March 2013 to $7.0 million in January through March 2014). Table 10-25 shows total revenue requirement charges from the first three months of years 2009 through 2014. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-25 Black start revenue requirement charges: January through March, 2009 through 2014

Year (Jan-Mar)	Revenue Requirement Charges
2009	$3,575,056
2010	$2,673,689
2011	$2,793,709
2012	$3,864,301
2013	$5,412,855
2014	$5,104,104

Black start zonal charges in the first three months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $28,280) to $3.50 per MW-day in the AEP Zone (total charges were $7,202,857). For each zone, Table 10-26 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.07 per MW of reserve capacity during the first three months of 2014.

Table 10-26 Black start zonal charges for network transmission use: January through March, 2013 and 2014

Zone	Jan-Mar 2013 Revenue Requirement Charges	Jan-Mar 2013 Operating Reserve Charges	Jan-Mar 2013 Total Charges	Jan-Mar 2013 Peak Load (MW-day)	Jan-Mar 2013 Black Start Rate ($/MW-day)	Jan-Mar 2014 Revenue Requirement Charges	Jan-Mar 2014 Operating Reserve Charges	Jan-Mar 2014 Total Charges	Jan-Mar 2014 Peak Load (MW-day)	Jan-Mar 2014 Black Start Rate ($/MW-day)
AECO	$129,109	$0	$129,109	252,810	$0.51	$153,360	$0	$153,360	246,528	$0.62
AEP	$152,241	$21,031,906	$21,184,148	2,097,774	$10.10	$166,432	$7,036,425	$7,202,857	2,056,167	$3.50
APS	$62,489	$0	$62,489	767,187	$0.08	$68,326	$0	$68,326	780,966	$0.09
ATSI	$36,944	$0	$36,944	1,216,341	$0.03	$28,280	$0	$28,280	1,182,699	$0.02
BGE	$1,948,411	$2,379	$1,950,791	630,180	$3.10	$1,139,947	$0	$1,139,947	614,727	$1.85
ComEd	$994,046	$0	$994,046	2,124,081	$0.47	$1,021,927	$0	$1,021,927	2,004,210	$0.51
DAY	$58,100	$5,252	$63,351	315,639	$0.20	$60,441	$6,511	$66,951	306,837	$0.22
DEOK	$78,620	$0	$78,620	490,050	$0.16	$281,806	$0	$281,806	463,140	$0.61
Dominion	NA	NA	NA	NA	NA	$248,851	$0	$248,851	1,688,670	$0.15
DPL	$139,995	$1,821	$141,816	370,269	$0.38	$136,765	$1,357	$138,122	361,683	$0.38
DLCO	$14,302	$0	$14,302	274,869	$0.05	$14,378	$0	$14,378	265,635	$0.05
EKPC	NA	NA	NA	NA	NA	$90,113	$0	$90,113	227,934	$0.40
JCPL	$138,665	$0	$138,665	559,746	$0.25	$119,801	$0	$119,801	574,101	$0.21
Met-Ed	$174,830	$0	$174,830	273,276	$0.64	$208,834	$0	$208,834	271,107	$0.77
PECO	$326,964	$8,104	$335,067	769,410	$0.44	$360,442	$2,343	$362,785	775,656	$0.47
PENELEC	$131,542	$0	$131,542	261,720	$0.50	$122,181	$0	$122,181	277,857	$0.44
Pepco	$71,788	$0	$71,788	604,863	$0.12	$75,854	$0	$75,854	588,006	$0.13
PPL	$40,195	$0	$40,195	664,335	$0.06	$35,102	$0	$35,102	665,298	$0.05
PSEG	$633,624	$0	$633,624	942,282	$0.67	$418,230	$0	$418,230	937,296	$0.45
RECO	$0	$0	$0	0	NA	$0	$0	$0	0	NA
(Imp/Exp/Wheels)	$280,990	$1,161,185	$1,442,175	691,609	$2.09	$353,034	$509,843	$862,877	1,062,418	$0.81
Total	$5,412,855	$22,210,646	$27,623,501	13,306,441	$2.08	$5,104,104	$7,556,479	$12,660,583	15,350,935	$0.82

Table 10-27 shows estimated black start revenue requirements by zone for delivery years 2014-2015 through 2016-2017 based on current, incoming, and outgoing black start resources.

Table 10-27 Revenue Requirement Estimate: Delivery Years 2014-2015 through 2016-2017

Zone	2014-2015 Revenue Requirement	2015-2016 Revenue Requirement	2016-2017 Revenue Requirement
AECO	$881,923	$2,422,980	$2,712,515
AEP	$10,739,321	$18,054,481	$18,070,565
APS	$309,424	$4,253,581	$4,256,090
ATSI	$2,592,447	$3,084,911	$3,086,491
BGE	$2,009,693	$1,488,297	$1,538,482
ComEd	$4,672,575	$5,292,902	$3,721,520
DAY	$272,203	$271,052	$274,403
DEOK	$1,224,221	$1,223,003	$1,226,548
Dominion	$1,606,732	$4,293,407	$5,985,460
DPL	$857,173	$2,160,879	$2,715,141
DLCO	$63,794	$185,467	$187,744
EKPC	$408,714	$406,733	$412,501
JCPL	$2,270,287	$7,428,656	$7,449,817
Met-Ed	$856,576	$812,061	$858,183
PECO	$1,613,435	$1,796,320	$1,873,591
PENELEC	$543,679	$4,629,185	$4,679,970
Pepco	$1,086,225	$2,604,867	$2,611,127
PPL	$199,874	$851,869	$859,863
PSEG	$7,085,539	$9,780,520	$9,802,397
RECO	$0	$0	$0
Total	$39,293,835	$71,041,172	$72,322,407

Table 10-28 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 10-28 NERC CIP Costs: January through March 2014

Capital Cost Requested	Cost Recovered in Jan-Mar 2014	Number of Units	MW
$1,736,971	$157,630	33	678

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[37] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

Total reactive service charges are the sum of reactive service revenue requirement charges and reactive service operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service revenue requirement charges are allocated monthly to PJM customers in the zone or zones where the reactive service was provided proportionally to their zone and non-zone peak transmission use and point to point transmission reservations. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. These operating reserve charges are allocated daily to the zone or zones where the reactive service was provided.

In the first three months of 2014, total reactive service charges were $77.7 million, a 37.3 percent decrease from the January through March 2013 level of $124.0 million.[38] While revenue requirement charges increased from $68.3 million to $70.2 million, operating reserve charges fell from $55.6 million to $7.5 million. The decrease in operating reserve charges was due to higher LMPs that caused more units that provide reactive service to be run economically rather than out of merit. Total charges in the first three months of 2014 ranged from $487 in the RECO Zone to $10.1 million in the AEP Zone.

37 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).
38 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

For each zone in the first three months of 2013 and 2014, Table 10-29 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-29 Reactive zonal charges for network transmission use: January through March 2013 and 2014

Zone	Jan-Mar 2013 Operating Reserve Charges	Jan-Mar 2013 Revenue Requirement Charges	Jan-Mar 2013 Total Charges	Jan-Mar 2014 Operating Reserve Charges	Jan-Mar 2014 Revenue Requirement Charges	Jan-Mar 2014 Total Charges
AECO	$2,131,642	$1,286,113	$3,417,756	$81,431	$1,255,482	$1,336,913
AEP	$3,261,003	$10,098,164	$13,359,167	$196,208	$9,857,657	$10,053,865
APS	$1,241,559	$5,498,190	$6,739,749	$249,479	$5,367,240	$5,616,719
ATSI	$19,213,959	$3,598,790	$22,812,749	$3,389,443	$3,963,356	$7,352,799
BGE	$926,837	$1,947,253	$2,874,090	$33,662	$1,900,875	$1,934,537
ComEd	$2,322,042	$6,156,138	$8,478,180	$34,089	$6,009,518	$6,043,607
DAY	$405,838	$2,114,120	$2,519,958	$5,699	$2,063,768	$2,069,468
DEOK	$632,597	$1,443,031	$2,075,629	$9,035	$1,408,663	$1,417,698
Dominion	$343,588	$7,498,436	$7,842,023	$4,883	$7,319,846	$7,324,729
DPL	$2,637,077	$2,428,619	$5,065,696	$33,131	$2,636,968	$2,670,099
DLCO	$6,554,423	$0	$6,554,423	$1,409,136	$0	$1,409,136
EKPC	NA	NA	$0	$4,764	$523,492	$528,256
JCPL	$5,080,722	$1,567,966	$6,648,689	$7,964	$1,743,078	$1,751,042
Met-Ed	$472,447	$1,874,196	$2,346,644	$15,074	$1,829,559	$1,844,633
PECO	$947,602	$4,415,638	$5,363,241	$259,820	$4,310,471	$4,570,292
PENELEC	$4,776,894	$1,165,247	$5,942,141	$1,339,940	$1,137,495	$2,477,435
Pepco	$853,079	$1,317,377	$2,170,455	$29,749	$1,286,001	$1,315,750
PPL	$1,030,291	$4,594,362	$5,624,653	$15,867	$4,710,500	$4,726,367
PSEG	$2,714,124	$6,832,188	$9,546,312	$357,998	$6,669,467	$7,027,465
RECO	$33,631	$0	$33,631	$487	$0	$487
(Imp/Exp/Wheels)	$0	$4,555,417	$4,555,417	$0	$6,239,393	$6,239,393
Total	$55,579,356	$68,391,246	$123,970,602	$7,477,860	$70,232,829	$77,710,689

Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the congestion component of LMP (CLMP), and the marginal loss component of LMP (MLMP).[1]

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[2] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,050.2 million or 564.8 percent, from $185.9 million in the first three months of 2013 to $1,236.1 million in the first three months of 2014. Total congestion costs increased because of the cold weather in January, which caused higher load and prices and an increased frequency of congestion.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,101.5 million or 331.9 percent, from $331.9 million in the first three months of 2013 to $1,433.3 million in the first three months of 2014.
- **Balancing Congestion.** Balancing congestion costs decreased by $51.3 million or 35.1 percent, from -$145.9 million in the first three months of 2013 to -$197.2 million in the first three months of 2014.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2014 ranged from $165.2 million in February to $825.2 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South Interface, the West Interface, the Breed - Wheatland flowgate, the Cloverdale transformer, and the Bedington - Black Oak Interface.
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first three months of 2014. Day-ahead congestion frequency increased by 39.7 percent from 81,378 congestion event hours in the

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June through June 2013.

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

3 The total congestion and marginal losses were calculated as of April 18, 2014, and are subject to change, based on continued PJM billing updates.

first three months of 2013 to 113,666 congestion event hours in the first three months of 2014. Day-ahead, congestion-event hours increased on all types of congestion facilities.

Real-time congestion frequency increased by 71.3 percent from 5,923 congestion event hours in the first three months of 2013 to 10,144 congestion event hours in the first three months of 2014. Real-time, congestion-event hours increased on all types of congestion facilities.

The AP South Interface was the largest contributor to congestion costs in the first three months of 2014. With $436.9 million in total congestion costs, it accounted for 35.3 percent of the total PJM congestion costs in the first three months of 2014.

- **Zonal Congestion.** AEP had the largest total congestion cost among all control zones in the first three months of 2014. AEP had -$710.8 million in total load congestion payments, -$1,088.3 million in total generation congestion credits and -$53.5 million in explicit congestion costs, resulting in $324.1 million in net congestion costs. The AP South interface, the West Interface, the Breed - Wheatland, Monticello - East Winamac and the Benton Harbor - Palisades flowgates contributed $253.4 million, or 78.2 percent of the total AEP Control Zone congestion costs.
- Ownership. In the first three months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first three months of 2014, financial companies received $190.8 million, an increase of $162.4 million or 571.9 percent compared to the first three months of 2013. In the first three months of 2014, physical companies paid $1,426.9 million in congestion charges, an increase of $1,212.6 million or 565.8 percent compared to the first three months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $498.3 million or 179.5 percent, from $277.6 million in the first three months of 2013 to $775.9 million in the first three months of 2014. Total marginal loss costs increased because of the cold weather in January, which caused higher load and prices and an increased level of losses. The loss component of LMP increased 35.9 percent, from $0.02 in the first three months of 2013 to $0.03 in the first three months of 2014. The loss MW in PJM increased 13.8 percent, from 5,352 GWh in the first three months of 2013 to 4,705 GWh in the first three months of 2013.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $535.0 million or 180.6 percent, from $296.2 million in the first three months of 2013 to $831.1 million in the first three months of 2014.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $36.6 million or 196.5 percent, from -$18.6 million in the first three months of 2013 to -$55.3 million in the first three months of 2013.
- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first three months of 2014 increased compared to the first three months of 2013, by 310.3 percent in January, 114.4 percent in February and 95.3 percent in March. Monthly total marginal loss costs in the first three months of 2014 ranged from $175.4 million in March to $414.6 million in January.
- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[4] The marginal loss credits increased in the first three months of 2014 by $158.0 million or 158.9 percent, from $99.4 million in the first three months of 2013, to $257.4 million in the first three months of 2014.

4 See PJM. "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), pp 63-64. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by \$337.3 million or 189.6 percent, from -\$177.9 million in the first three months of 2013 to -\$515.1 million in the first three months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by \$477.1 million or 246.3 percent, from -\$193.7 million in the first three months of 2013 to -\$670.9 million in the first three months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by \$146.8 million or 924.9 percent, from \$15.9 million in the first three months of 2013 to \$162.6 million in the first three months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first three months of 2014 ranged from -\$272.5 million in January to -\$119.6 million in March.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion in 2013. ARR and FTR revenues offset 97.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Locational Marginal Price (LMP)

Components

Table 11-1 shows the PJM real-time, load-weighted average LMP components for the first three months of 2009 to 2014. The load-weighted average real-time LMP increased \$55.57 or 148.5 percent from \$37.41 in the first three months of 2013 to \$92.98 in the first three months of 2014. The load-weighted average congestion component decreased \$0.15 or 701.0 percent from \$0.02 in the first three months of 2013 to -\$0.13 in the first three months of 2014. The load-weighted average loss component increased \$0.01 or 35.9 percent from \$0.02 in the first three months of 2013 to \$0.03 in the first three months of 2014. The load-weighted average energy component increased \$55.71 or 149.1 percent from \$37.37 in the first three months of 2013 to \$93.08 in the first three months of 2014. Given that these results are based on system average LMP including offsetting congestion components, a congestion component near zero is expected.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2009 through 2014[5]

(Jan-Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	\$49.60	\$49.51	\$0.05	\$0.04
2010	\$45.92	\$45.81	\$0.06	\$0.05
2011	\$46.35	\$46.30	\$0.03	\$0.03
2012	\$31.21	\$31.18	\$0.02	\$0.00
2013	\$37.41	\$37.37	\$0.02	\$0.02
2014	\$92.98	\$93.08	(\$0.13)	\$0.03

5 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first three months of 2009 through 2014. The load-weighted average day-ahead LMP increased $57.71 or 154.9 percent from $37.26 in the first three months of 2013 to $94.97 in the first three months of 2014. The load-weighted average congestion component increased $0.36 or 549.0 percent from $0.07 in the first three months of 2013 to $0.43 in the first three months of 2014. The load-weighted average loss component decreased $0.01 or 67.2 percent from $0.01 in the first three months of 2013 to $0.00 in the first three months of 2014. The load-weighted average energy component increased $57.34 or 154.2 percent from $37.19 in the first three months of 2013 to $94.52 in the first three months of 2014.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2009 through 2014

(Jan-Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01
2014	$94.97	$94.52	$0.43	$0.00

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for the first three months of 2013 and the first three months of 2014.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2013 and 2014

	2013 (Jan-Mar)				2014 (Jan-Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$38.44	$37.27	($0.43)	$1.60	$108.65	$91.45	$12.48	$4.71
AEP	$35.34	$37.35	($1.09)	($0.92)	$74.34	$93.18	($15.80)	($3.04)
AP	$36.97	$37.43	($0.41)	($0.04)	$90.46	$93.85	($4.12)	$0.73
ATSI	$35.70	$37.21	($1.73)	$0.22	$75.47	$90.21	($15.29)	$0.55
BGE	$42.02	$37.59	$2.52	$1.91	$128.07	$95.95	$27.14	$4.99
ComEd	$31.60	$37.04	($3.36)	($2.08)	$60.88	$89.49	($22.49)	($6.12)
DAY	$35.14	$37.38	($2.13)	($0.11)	$71.49	$92.91	($20.25)	($1.16)
DEOK	$33.20	$37.35	($2.23)	($1.92)	$68.06	$93.47	($19.38)	($6.02)
DLCO	$33.77	$37.19	($2.12)	($1.30)	$65.29	$90.36	($21.91)	($3.16)
Dominion	$40.68	$37.69	$2.54	$0.45	$121.48	$97.23	$23.49	$0.76
DPL	$39.53	$37.63	($0.39)	$2.28	$122.76	$96.58	$18.74	$7.44
EKPC	NA	NA	NA	NA	$74.73	$99.98	($19.75)	($5.50)
JCPL	$40.33	$37.43	$1.10	$1.80	$109.43	$91.21	$12.75	$5.47
Met-Ed	$38.12	$37.46	($0.06)	$0.72	$108.44	$92.68	$12.40	$3.35
PECO	$37.23	$37.35	($1.20)	$1.08	$108.92	$92.45	$12.48	$3.99
PENELEC	$38.10	$37.29	$0.30	$0.52	$87.94	$91.06	($4.57)	$1.44
Pepco	$42.05	$37.62	$3.05	$1.39	$128.56	$95.53	$29.46	$3.58
PPL	$37.61	$37.46	($0.51)	$0.66	$109.25	$93.24	$13.10	$2.92
PSEG	$47.59	$37.21	$8.88	$1.50	$115.99	$90.43	$20.17	$5.39
RECO	$53.46	$37.33	$14.74	$1.39	$114.01	$90.54	$18.25	$5.23
PJM	$37.41	$37.37	$0.02	$0.02	$92.98	$93.08	($0.13)	$0.03

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first three months of 2013 and the first three months of 2014.

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2013 and 2014

	2013 (Jan-Mar)				2014 (Jan-Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$38.64	$37.26	($0.30)	$1.68	$116.60	$92.85	$19.45	$4.30
AEP	$34.99	$37.19	($1.27)	($0.92)	$78.00	$96.48	($15.59)	($2.89)
AP	$36.49	$37.24	($0.75)	$0.01	$88.22	$94.17	($6.04)	$0.09
ATSI	$35.53	$37.14	($1.66)	$0.05	$79.66	$92.23	($13.21)	$0.64
BGE	$41.70	$37.33	$2.52	$1.85	$128.50	$97.10	$27.32	$4.08
ComEd	$31.83	$37.00	($2.82)	($2.36)	$66.20	$92.49	($21.90)	($4.39)
DAY	$35.36	$37.28	($1.74)	($0.18)	$77.53	$96.00	($17.64)	($0.83)
DEOK	$33.41	$37.09	($1.91)	($1.77)	$72.57	$93.99	($16.32)	($5.10)
DLCO	$33.48	$37.11	($2.34)	($1.28)	$68.77	$91.88	($19.62)	($3.49)
Dominion	$40.25	$37.48	$2.32	$0.45	$110.58	$98.10	$12.74	($0.26)
DPL	$39.53	$37.28	($0.12)	$2.37	$128.99	$96.70	$25.90	$6.39
EKPC	NA	NA	NA	NA	$77.42	$100.93	($18.00)	($5.51)
JCPL	$40.62	$37.28	$1.32	$2.02	$121.82	$93.97	$22.11	$5.74
Met-Ed	$38.03	$37.06	$0.25	$0.72	$114.57	$93.22	$18.45	$2.90
PECO	$37.56	$37.10	($0.68)	$1.14	$116.42	$93.68	$18.90	$3.84
PENELEC	$38.25	$37.13	$0.30	$0.82	$92.74	$92.89	($1.99)	$1.85
Pepco	$41.64	$37.22	$3.02	$1.39	$124.74	$95.99	$25.80	$2.95
PPL	$37.66	$37.15	($0.09)	$0.60	$116.23	$94.03	$19.82	$2.39
PSEG	$46.55	$37.20	$7.51	$1.85	$128.85	$93.02	$30.13	$5.70
RECO	$50.35	$37.27	$11.50	$1.58	$124.00	$91.14	$27.45	$5.41
PJM	$37.26	$37.19	$0.07	$0.01	$94.97	$94.52	$0.43	$0.00

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for the first three months of 2013 and the first three months of 2014.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2013 and 2014

	2013 (Jan-Mar)				2014 (Jan-Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.03	$37.34	($2.20)	($2.11)	$61.39	$88.23	($20.16)	($6.68)
AEP-DAY Hub	$34.91	$37.34	($1.40)	($1.03)	$67.48	$90.18	($19.17)	($3.53)
ATSI Gen Hub	$34.56	$36.37	($1.53)	($0.28)	$75.12	$92.55	($16.45)	($0.97)
Chicago Gen Hub	$30.64	$36.74	($3.55)	($2.55)	$57.58	$88.88	($23.90)	($7.40)
Chicago Hub	$31.83	$37.18	($3.33)	($2.02)	$61.27	$89.85	($22.58)	($5.99)
Dominion Hub	$41.02	$38.37	$2.60	$0.04	$122.57	$100.24	$22.86	($0.53)
Eastern Hub	$38.67	$37.04	($0.57)	$2.20	$113.36	$90.98	$15.72	$6.66
N Illinois Hub	$31.17	$36.82	($3.41)	($2.24)	$59.07	$87.81	($22.28)	($6.45)
New Jersey Hub	$44.24	$37.28	$5.38	$1.58	$112.36	$90.65	$16.44	$5.27
Ohio Hub	$34.55	$37.23	($1.71)	($0.98)	$68.20	$91.31	($19.68)	($3.43)
West Interface Hub	$36.23	$37.13	($0.34)	($0.56)	$86.49	$90.55	($2.28)	($1.78)
Western Hub	$38.99	$37.97	$0.81	$0.21	$100.56	$93.78	$6.21	$0.57

The day-ahead components of LMP for each hub are presented in Table 11-6 for the first three months of 2013 and the first three months of 2014.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2013 and 2014

	2013 (Jan-Mar)				2014 (Jan-Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$32.68	$36.54	($1.90)	($1.97)	$62.52	$81.82	($13.85)	($5.45)
AEP-DAY Hub	$34.40	$36.84	($1.39)	($1.05)	$71.69	$90.45	($16.06)	($2.71)
ATSI Gen Hub	$35.54	$37.41	($1.57)	($0.30)	$68.00	$74.22	($6.31)	$0.08
Chicago Gen Hub	$31.14	$36.94	($3.01)	($2.80)	$60.91	$88.74	($22.34)	($5.49)
Chicago Hub	$32.06	$36.93	($2.64)	($2.22)	$60.21	$83.17	($19.26)	($3.70)
Dominion Hub	$39.95	$37.54	$2.30	$0.11	$107.82	$97.74	$11.65	($1.57)
Eastern Hub	$39.43	$37.28	($0.28)	$2.42	$118.16	$90.69	$21.26	$6.21
N Illinois Hub	$31.66	$36.98	($2.87)	($2.45)	$61.92	$87.88	($21.31)	($4.65)
New Jersey Hub	$43.63	$37.12	$4.66	$1.85	$117.00	$88.83	$23.04	$5.12
Ohio Hub	$34.36	$36.77	($1.37)	($1.05)	$72.58	$91.84	($16.86)	($2.40)
West Interface Hub	$38.63	$39.47	($0.40)	($0.44)	$73.56	$76.84	($2.00)	($1.29)
Western Hub	$38.24	$37.07	$0.78	$0.39	$96.27	$90.46	$5.22	$0.58

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for the first three months of 2009 through 2014. These totals are actually net energy, loss and congestion costs.

Table 11-7 Total PJM costs by component (Dollars (Millions)): January through March of 2009 through 2014[6] [7]

	Component Costs (Millions)					
(Jan-Mar)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($218)	$454	$307	$543	$7,515	7.2%
2010	($208)	$417	$345	$554	$8,415	6.6%
2011	($210)	$410	$360	$560	$9,584	5.8%
2012	($136)	$234	$122	$220	$6,938	3.2%
2013	($178)	$278	$186	$286	$7,762	3.7%
2014	($515)	$776	$1,236	$1,497	$21,070	7.1%

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[8] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the Balancing Energy Market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[9]

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and Balancing Energy Markets.

Total congestion costs in PJM in the first three months of 2014 were $1,236.1 million, which was comprised of load congestion payments of $406.7 million, generation credits of -$985.0 million and explicit congestion of -$155.6 million (Table 11-9).

Total Congestion

Table 11-8 shows total congestion for the first three months of 2008 through 2014.

Table 11-8 Total PJM congestion (Dollars (Millions)): January through March of 2008 through 2014

	Congestion Costs (Millions)			
(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$485.6	NA	$7,718	6.3%
2009	$306.9	(36.8%)	$7,515	4.1%
2010	$344.9	12.4%	$8,415	4.1%
2011	$359.9	4.3%	$9,584	3.8%
2012	$122.4	(66.0%)	$6,938	1.8%
2013	$185.9	51.9%	$7,762	2.4%
2014	$1,236.1	564.8%	$21,070	5.9%

Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[10] [11]

Table 11-9 shows the congestion costs by accounting category for the first three months of 2014. In the first three months of 2014 PJM total congestion costs were comprised of $406.7 million in load congestion payments, -$985.0 million in generation congestion credits, and -$155.6 million in explicit congestion costs.

6 The energy costs, loss costs and congestion costs include net inadvertent charges.
7 Total PJM billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.
8 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term congestion costs as used here.
9 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate.
10 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed April 17, 2013).
11 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 11-9 Total PJM congestion costs by accounting category (Dollars (Millions)): January through March of 2008 through 2014

	Congestion Costs (Millions)				
(Jan - Mar)	Load Payments	GenerationCredits	Explicit Costs	Inadvertent Charges	Total
2008	$286.4	($190.5)	$8.7	$0.0	$485.6
2009	$106.0	($227.3)	($26.5)	($0.0)	$306.9
2010	$80.1	($281.0)	($16.2)	($0.0)	$344.9
2011	$198.1	($199.0)	($37.2)	$0.0	$359.9
2012	$16.8	($120.1)	($14.5)	$0.0	$122.4
2013	$78.4	($125.8)	($18.2)	$0.0	$185.9
2014	$406.7	($985.0)	($155.6)	$0.0	$1,236.1

Table 11-10 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January through March of 2008 through 2014

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1

Monthly Congestion

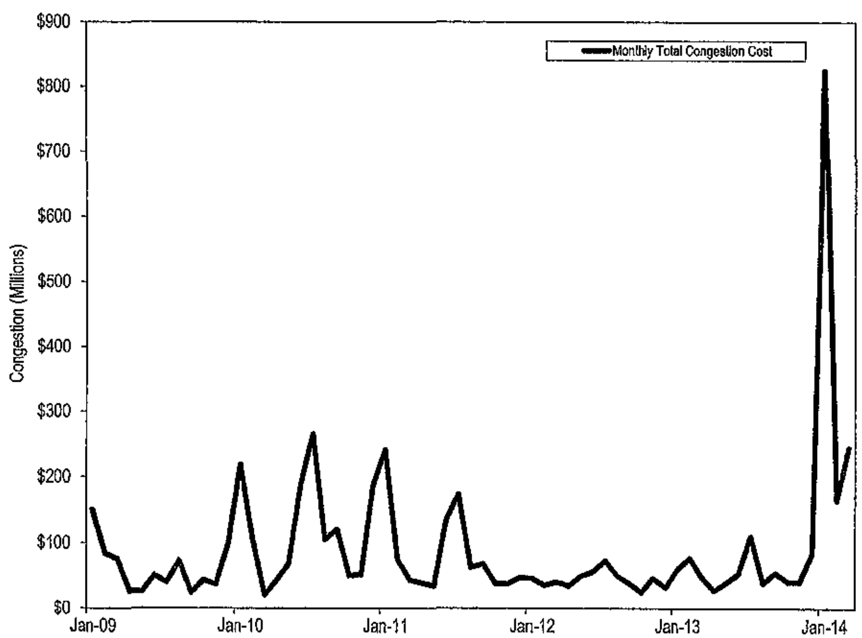
Table 11-11 shows that monthly total congestion costs ranged from $165.2 million to $825.2 million in 2014. Table 11-11 shows that monthly congestion costs in each of the first three months of 2014 were substantially higher than in the corresponding months of 2013.

Table 11-11 Monthly PJM congestion costs by market (Dollars (Millions)): January through March of 2013 and 2014

	Congestion Costs (Millions)							
	2013 (Jan-Mar)				2014 (Jan-Mar)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$136.8	($76.8)	$0.0	$60.0	$922.5	($97.3)	$0.0	$825.2
Feb	$125.1	($47.7)	$0.0	$77.4	$203.5	($38.3)	$0.0	$165.2
Mar	$69.9	($21.4)	($0.0)	$48.5	$307.3	($61.6)	$0.0	$245.8
Total	$331.9	($145.9)	$0.0	$185.9	$1,433.3	($197.2)	$0.0	$1,236.1

Figure 11-1 shows PJM monthly total congestion cost for 2009 through the first three months of 2014.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through March of 2014



Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first three months of 2014, there were 113,666 day-ahead, congestion-event hours compared to 81,378 day-ahead, congestion-event hours in the first three months of 2013. In the first three months of 2014, there were 10,144 real-time, congestion-event hours compared to 5,924 real-time, congestion-event hours in the first three months of 2013.

During the first three months of 2014, for only 3.6 percent of day-ahead energy market facility constrained hours were the same facilities also constrained in the Real-Time Energy Market. During the first three months of 2014, for 44.2 percent of real-time energy market facility constrained hours, the same facilities were also constrained in the Day-Ahead Energy Market.

The AP South Interface was the largest contributor to congestion costs in the first three months of 2014. With $436.9 million in total congestion costs, it accounted for 35.3 percent of the total PJM congestion costs in the first three months of 2014. The top five constraints in terms of congestion costs together contributed $762.2 million, or 61.7 percent, of the total PJM congestion costs in the first three months of 2014. The top five constraints were the AP South Interface, the West Interface, the Breed – Wheatland flowgate, and the Cloverdale transformer, and the Bedington - Black Oak Interface.

Congestion by Facility Type and Voltage

In the first three months of 2014, compared to the first three months of 2013, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours increased on all types of facilities.

Day-ahead congestion costs increased on all types of facilities in the first three months of 2014 compared to the first three months of 2013. Balancing congestion costs decreased on flowgates, interfaces and transformers and increased on transmission lines in the first three months of 2014 compared to the first three months of 2013.

Table 11-12 provides congestion-event hour subtotals and congestion cost subtotals comparing the first three months of 2014 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[12] [13] For comparison, this information is presented in Table 11-13 for the first three months of 2013.[14]

Table 11-12 Congestion summary (By facility type): January through March of 2014

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($53.5)	($253.7)	($15.4)	$184.8	$1.1	$12.2	($30.8)	($41.9)	$143.0	10,847	3,037
Interface	$300.6	($579.4)	($100.6)	$779.4	$61.3	$142.6	$24.1	($57.1)	$722.3	7,042	1,850
Line	$26.1	($290.6)	$0.8	$317.5	($2.3)	$40.2	($21.8)	($64.2)	$253.3	58,732	4,420
Other	($0.1)	($0.5)	$0.3	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,622	0
Transformer	$60.0	($61.8)	$10.9	$132.7	$8.2	$13.0	($41.8)	($46.6)	$86.1	35,423	837
Unclassified	$0.6	($8.0)	$9.7	$18.3	$4.6	$1.0	$9.0	$12.6	$30.9	NA	NA
Total	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$1,236.1	113,666	10,144

Table 11-13 Congestion summary (By facility type): January through March of 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($5.8)	($39.1)	$6.6	$39.9	$1.3	$7.1	($18.2)	($23.9)	$16.0	5,414	2,333
Interface	$69.4	($44.2)	($1.0)	$112.5	$6.9	$14.8	$1.8	($6.0)	$106.5	3,571	609
Line	$11.7	($93.8)	$24.4	$130.0	($12.1)	$44.5	($38.6)	($95.2)	$34.8	47,137	2,482
Other	$2.8	($1.8)	$5.1	$9.7	($0.0)	$0.0	$0.0	($0.0)	$9.7	4,443	5
Transformer	$6.9	($14.9)	$7.7	$29.5	($2.2)	$6.3	($10.3)	($18.8)	$10.7	20,813	494
Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	NA	NA
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$185.9	81,378	5,923

12 Unclassified are congestion costs related to non-transmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Non-transmission facility constraints include Day-Ahead Market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.
13 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.
14 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

Table 11-14 and Table 11-15 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-14. In the first three months of 2014, there were 113,666 congestion event hours in the Day-Ahead Energy Market. Among those day-ahead congestion event hours, only 4,115 (3.6 percent) were also constrained in the Real-Time Energy Market. In the first three months of 2013, among the 8,378 day-ahead congestion event hours, only 2,519 (3.1 percent) were binding in the Real-Time Energy Market.[15]

Among the hours for which a facility is constrained in the Real-Time Energy Market, the number of hours during which the facility is also constrained in the Day-Ahead Energy Market are presented in Table 11-15. In the first three months of 2014, there were 10,144 congestion event hours in the Real-Time Energy Market. Among these real-time congestion event hours, 4,484 (44.2 percent) were also constrained in the Day-Ahead Energy Market. In the first three months of 2013, among the 5,923 real-time congestion event hours, only 2,669 (45.1 percent) were also in the Day-Ahead Energy Market.

Table 11-14 Congestion event hours (Day-Ahead against Real-Time): January through March of 2013 and 2014

	Congestion Event Hours					
	2013 (Jan - Mar)			2014 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	5,414	907	16.8%	10,847	1,542	14.2%
Interface	3,571	509	14.3%	7,042	1,086	15.4%
Line	47,137	895	1.9%	58,732	1,298	2.2%
Other	4,443	5	0.1%	1,622	0	0.0%
Transformer	20,813	203	1.0%	35,423	189	0.5%
Total	81,378	2,519	3.1%	113,666	4,115	3.6%

Table 11-15 Congestion event hours (Real-Time against Day-Ahead): January through March of 2013 and 2014

	Congestion Event Hours					
	2013 (Jan - Mar)			2014 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	2,333	1,041	44.6%	3,037	1,635	53.8%
Interface	609	525	86.2%	1,850	1,388	75.0%
Line	2,482	896	36.1%	4,420	1,293	29.3%
Other	5	5	100.0%	0	0	0.0%
Transformer	494	202	40.9%	837	168	20.1%
Total	5,923	2,669	45.1%	10,144	4,484	44.2%

15 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 11-16 shows congestion costs by facility voltage class for the first three months of 2014. In comparison to the first three months of 2013 (shown in Table 11-17), congestion costs decreased for facilities rated at 138 kV and 115 kV 2013.

Table 11-16 Congestion summary (By facility voltage): January through March of 2014

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$21.8	($28.8)	$0.9	$51.5	$0.1	$0.2	($0.0)	($0.1)	$51.4	3,315	5
500	$310.3	($573.5)	($101.3)	$782.4	$69.7	$158.9	$9.0	($80.2)	$702.2	9,108	2,007
345	($53.6)	($243.5)	($9.9)	$180.0	$2.8	$14.0	($21.9)	($33.1)	$146.9	22,632	1,604
230	$5.1	($184.1)	($17.4)	$171.9	$1.3	($3.1)	$8.8	$13.2	$185.0	18,933	1,495
161	($4.7)	($10.8)	$0.5	$6.6	($1.5)	($0.5)	($0.8)	($1.9)	$4.7	1,459	289
138	$31.6	($147.8)	$20.9	$200.3	($0.3)	$36.8	($64.6)	($101.8)	$98.5	47,639	4,346
115	$0.3	($2.7)	$1.4	$4.4	($1.3)	$0.6	($0.3)	($2.3)	$2.1	4,532	214
69	$22.3	$5.2	$0.9	$18.0	($2.3)	$1.0	($0.3)	($3.6)	$14.4	4,581	184
34	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,467	0
-99	$0.6	($8.0)	$9.7	$18.3	$4.6	$1.0	$9.0	$12.6	$30.9	NA	NA
Total	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$1,236.1	113,666	10,144

Table 11-17 Congestion summary (By facility voltage): January through March of 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$5.2	($2.9)	$3.7	$11.8	$0.0	$0.0	$0.0	$0.0	$11.8	2,027	0
500	$72.5	($49.3)	($0.5)	$121.3	$8.7	$15.1	($1.6)	($8.1)	$113.2	4,454	724
345	($4.1)	($27.8)	$6.7	$30.4	($1.3)	$8.9	($15.3)	($25.5)	$5.0	12,864	1,559
230	$11.9	($74.4)	$22.0	$108.2	($11.0)	$43.1	($30.9)	($85.0)	$23.2	15,851	1,330
161	($1.7)	($3.1)	($0.6)	$0.8	($0.4)	$0.2	($0.1)	($0.7)	$0.1	654	407
138	$0.6	($33.2)	$10.2	$44.1	($0.5)	$4.4	($16.4)	($21.4)	$22.7	34,864	1,668
115	($0.0)	($2.8)	$0.6	$3.3	($0.3)	$0.2	($0.1)	($0.6)	$2.7	3,366	176
69	$0.5	($0.3)	$0.7	$1.6	($1.2)	$0.7	($0.7)	($2.6)	($1.0)	4,394	59
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2,893	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	NA	NA
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$185.9	81,378	5,923

Constraint Duration

Table 11-18 lists the constraints in the first three months of 2013 and the first three months of 2014 that were most frequently in effect and Table 11-19 shows the constraints which experienced the largest change in congestion-event hours from the first three months of 2013 to the first three months of 2014.

Table 11-18 Top 25 constraints with frequent occurrence: January through March of 2013 and 2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	AP South	Interface	2,012	2,347	335	505	864	359	23%	27%	4%	6%	10%	4%
2	Tanners Creek	Transformer	1,458	3,110	1,652	0	0	0	17%	35%	19%	0%	0%	0%
3	Miami Fort	Transformer	835	2,494	1,659	0	21	21	10%	28%	19%	0%	0%	0%
4	Monticello - East Winamac	Flowgate	998	1,489	491	387	1,004	617	11%	17%	6%	4%	11%	7%
5	Braidwood	Transformer	1,168	2,288	1,120	0	0	0	13%	26%	13%	0%	0%	0%
6	Breed - Wheatland	Flowgate	724	1,853	1,129	148	433	285	8%	21%	13%	2%	5%	3%
7	Nelson - Cordova	Line	1,112	2,034	922	3	139	136	13%	23%	10%	0%	2%	2%
8	Sunbury	Transformer	748	2,053	1,305	0	0	0	9%	23%	15%	0%	0%	0%
9	Kendall Co. Energy Ctr.	Transformer	0	1,984	1,984	0	0	0	0%	23%	23%	0%	0%	0%
10	Keeney	Transformer	151	1,742	1,591	0	50	50	2%	20%	18%	0%	1%	1%
11	Oak Grove - Galesburg	Flowgate	654	1,459	805	362	215	(147)	7%	17%	9%	4%	2%	(2%)
12	East Bend	Transformer	0	1,601	1,601	0	0	0	0%	18%	18%	0%	0%	0%
13	Clinch River	Transformer	0	1,562	1,562	0	0	0	0%	18%	18%	0%	0%	0%
14	Mardela - Vienna	Line	9	1,501	1,492	22	2	(20)	0%	17%	17%	0%	0%	(0%)
15	Gould Street - Westport	Line	2,893	1,467	(1,426)	0	0	0	33%	17%	(16%)	0%	0%	0%
16	Sporn	Transformer	3,174	1,427	(1,747)	0	0	0	36%	16%	(20%)	0%	0%	0%
17	Wolf Creek	Transformer	0	1,290	1,290	0	80	80	0%	15%	15%	0%	1%	1%
18	West	Interface	341	1,022	681	1	345	344	4%	12%	8%	0%	4%	4%
19	Readington - Roseland	Line	1,925	1,169	(756)	609	189	(420)	22%	13%	(9%)	7%	2%	(5%)
20	Chicago Heights - Bloom	Line	0	1,315	1,315	0	0	0	0%	15%	15%	0%	0%	0%
21	Beckjord	Transformer	783	1,297	514	0	0	0	9%	15%	6%	0%	0%	0%
22	Loretto - Cayuga	Line	132	1,295	1,163	0	0	0	2%	15%	13%	0%	0%	0%
23	Argenta - Greenup	Line	0	1,281	1,281	0	0	0	0%	15%	15%	0%	0%	0%
24	East	Interface	55	1,217	1,162	4	17	13	1%	14%	13%	0%	0%	0%
25	Benton Harbor - Palisades	Flowgate	0	1,096	1,096	4	97	93	0%	12%	12%	0%	1%	1%

Table 11-19 Top 25 constraints with largest year-to-year change in occurrence: January through March of 2013 and 2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Kendall Co. Energy Ctr.	Transformer	0	1,984	1,984	0	0	0	0%	23%	23%	0%	0%	0%
2	Sporn	Transformer	3,174	1,427	(1,747)	0	0	0	36%	16%	(20%)	0%	0%	0%
3	Miami Fort	Transformer	835	2,494	1,659	0	21	21	10%	28%	19%	0%	0%	0%
4	Tanners Creek	Transformer	1,458	3,110	1,652	0	0	0	17%	35%	19%	0%	0%	0%
5	Keeney	Transformer	151	1,742	1,591	0	50	50	2%	20%	18%	0%	1%	1%
6	Devon - Skokie	Line	1,697	68	(1,629)	0	0	0	19%	1%	(19%)	0%	0%	0%
7	East Bend	Transformer	0	1,601	1,601	0	0	0	0%	18%	18%	0%	0%	0%
8	Prairie State - W Mt. Vernon	Flowgate	897	0	(897)	692	0	(692)	10%	0%	(10%)	8%	0%	(8%)
9	Clinch River	Transformer	0	1,562	1,562	0	0	0	0%	18%	18%	0%	0%	0%
10	Mardela - Vienna	Line	9	1,501	1,492	22	2	(20)	0%	17%	17%	0%	0%	(0%)
11	Gould Street - Westport	Line	2,893	1,467	(1,426)	0	0	0	33%	17%	(16%)	0%	0%	0%
12	Breed - Wheatland	Flowgate	724	1,853	1,129	148	433	285	8%	21%	13%	2%	5%	3%
13	Wolf Creek	Transformer	0	1,290	1,290	0	80	80	0%	15%	15%	0%	1%	1%
14	Chicago Heights - Bloom	Line	0	1,315	1,315	0	0	0	0%	15%	15%	0%	0%	0%
15	Waldwick - Waldwick	Other	1,315	0	(1,315)	0	0	0	15%	0%	(15%)	0%	0%	0%
16	Sunbury	Transformer	748	2,053	1,305	0	0	0	9%	23%	15%	0%	0%	0%
17	Argenta - Greenup	Line	0	1,281	1,281	0	0	0	0%	15%	15%	0%	0%	0%
18	Haurd - Steward	Line	1,533	300	(1,233)	0	0	0	18%	3%	(14%)	0%	0%	0%
19	Benton Harbor - Palisades	Flowgate	0	1,096	1,096	4	97	93	0%	12%	12%	0%	1%	1%
20	Burlington - Croydon	Line	0	1,180	1,180	0	0	0	0%	13%	13%	0%	0%	0%
21	Readington - Roseland	Line	1,925	1,169	(756)	609	189	(420)	22%	13%	(9%)	7%	2%	(5%)
22	East	Interface	55	1,217	1,162	4	17	13	1%	14%	13%	0%	0%	0%
23	Loretto - Cayuga	Line	132	1,295	1,163	0	0	0	2%	15%	13%	0%	0%	0%
24	Braidwood	Transformer	1,168	2,288	1,120	0	0	0	13%	26%	13%	0%	0%	0%
25	Monticello - East Winamac	Flowgate	998	1,489	491	387	1,004	617	11%	17%	6%	4%	11%	7%

Constraint Costs

Table 11-20 and Table 11-21 present the top constraints affecting congestion costs by facility for the periods the first three months of 2014 and the first three months of 2013.

Table 11-20 Top 25 constraints affecting PJM congestion costs (By facility): January through March of 2014

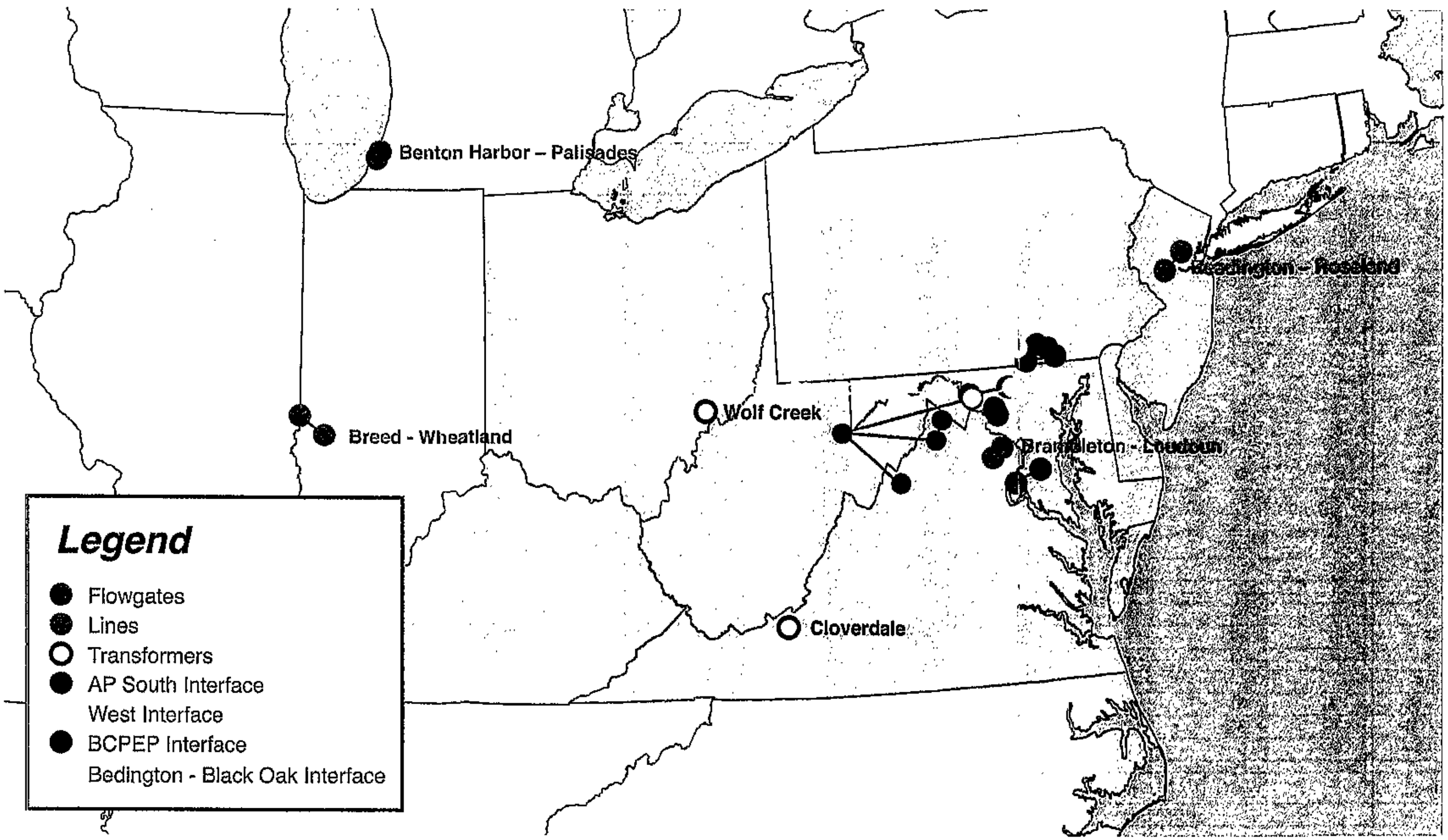
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2014 (Jan - Mar)
1	AP South	Interface	500	$295.7	($185.8)	($11.7)	$469.8	$31.1	$73.1	$9.1	($32.8)	$436.9	35.3%
2	West	Interface	500	($19.9)	($282.4)	($77.9)	$184.5	$16.7	$47.7	$16.7	($14.3)	$170.2	13.8%
3	Breed - Wheatland	Flowgate	MISO	($13.9)	($78.9)	($8.4)	$56.5	$2.1	$1.3	$5.7	$6.5	$63.0	5.1%
4	Cloverdale	Transformer	AEP	$21.6	($25.8)	($0.5)	$46.8	$0.0	$0.0	$0.0	$0.0	$46.8	3.8%
5	Bedington - Black Oak	Interface	500	$20.5	($30.7)	($2.3)	$48.8	$1.4	$3.9	($1.2)	($3.6)	$45.2	3.7%
6	Benton Harbor - Palisades	Flowgate	MISO	($10.9)	($64.0)	($7.3)	$45.8	($0.2)	$0.7	($0.7)	($1.6)	$44.2	3.6%
7	BCPEP	Interface	Pepco	$8.4	($14.6)	($2.1)	$21.0	($1.7)	($14.1)	$1.4	$13.8	$34.8	2.8%
8	Unclassified	Unclassified	Unclassified	$0.6	($8.0)	$9.7	$18.3	$4.6	$1.0	$9.0	$12.6	$30.9	2.5%
9	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	2.1%
10	Wolf Creek	Transformer	AEP	$2.2	($0.2)	$2.2	$4.7	$2.9	$5.1	($27.0)	($29.2)	($24.5)	(2.0%)
11	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.9%
12	Wescosville	Transformer	PPL	$17.3	($0.9)	$2.7	$20.9	($0.0)	$0.0	$0.0	($0.0)	$20.9	1.7%
13	Monticello - East Winamac	Flowgate	MISO	($3.1)	($30.3)	$0.0	$27.2	$1.7	$3.8	($5.6)	($7.6)	$19.5	1.6%
14	Cook - Palisades	Flowgate	MISO	($8.9)	($42.8)	($5.4)	$28.5	($1.5)	$1.6	($6.2)	($9.3)	$19.2	1.6%
15	Cloverdale	Transformer	AEP	$17.3	($4.4)	($2.7)	$18.9	$0.0	$0.0	$0.0	$0.0	$18.9	1.5%
16	Bridgewater - Middlesex	Line	PSEG	($0.2)	($21.7)	($3.0)	$18.6	($1.4)	$0.1	$1.4	($0.1)	$18.4	1.5%
17	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	1.3%
18	East	Interface	500	($6.2)	($25.1)	($3.0)	$15.9	$0.3	$0.7	$0.5	$0.1	$16.0	1.3%
19	Rising	Flowgate	MISO	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	(1.1%)
20	5004/5005 Interface	Interface	500	$0.4	($17.6)	($2.7)	$15.3	$7.7	$17.5	$7.1	($2.7)	$12.6	1.0%
21	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	$2.0	$3.9	($10.6)	($12.5)	($12.5)	(1.0%)
22	Nelson - Cordova	Line	ComEd	($16.7)	($30.8)	$1.3	$15.4	($0.7)	$0.8	($2.6)	($4.1)	$11.3	0.9%
23	Bergen - New Milford	Line	PSEG	$13.4	$6.8	$3.9	$10.5	$0.0	$0.0	$0.0	$0.0	$10.5	0.8%
24	Wake - Carso	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	(0.7%)
25	Huntington Junction - Huntington	Line	AP	$2.3	($17.6)	($10.7)	$9.2	$0.0	$0.0	$0.0	$0.0	$9.2	0.7%

Table 11-21 Top 25 constraints affecting PJM congestion costs (By facility): January through March of 2013

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan - Mar)
1	AP South	Interface	500	$62.2	($23.0)	$0.2	$85.4	$5.8	$10.8	$1.4	($3.6)	$81.8	44.0%
2	Readington - Roseland	Line	PSEG	$1.5	($41.1)	$8.5	$51.2	($10.7)	$37.0	($21.4)	($69.1)	($17.9)	(9.6%)
3	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.1)	$5.2	($6.4)	($11.7)	($11.7)	(6.3%)
4	Cloverdale	Transformer	AEP	$5.2	($2.6)	$3.1	$10.9	$0.0	$0.0	$0.0	$0.0	$10.9	5.9%
5	West	Interface	500	$1.9	($8.4)	($0.6)	$9.8	$0.0	$0.0	($0.0)	($0.0)	$9.7	5.2%
6	Bridgewater - Middlesex	Line	PSEG	$0.0	($13.3)	$1.0	$14.3	($0.0)	$3.5	($1.2)	($4.7)	$9.6	5.1%
7	Unclassified	Unclassified	Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	4.4%
8	Crete - St Johns Tap	Flowgate	MISO	($0.4)	($5.8)	$2.2	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	4.1%
9	New Dover - Westfield	Line	PSEG	$0.6	($5.6)	$0.9	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	3.8%
10	Bristers - Ox	Line	Dominion	$2.4	($2.5)	$0.4	$5.4	$0.8	$0.3	($0.3)	$0.1	$5.5	3.0%
11	Breed - Wheatland	Flowgate	MISO	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.0)	($1.0)	$5.4	2.9%
12	5004/5005 Interface	Interface	500	$1.0	($6.7)	($0.3)	$7.3	$1.2	$3.9	$0.4	($2.3)	$5.0	2.7%
13	Bedington	Transformer	AP	$1.7	($2.9)	$0.1	$4.7	$0.1	$0.1	$0.0	$0.0	$4.8	2.6%
14	AEP - DOM	Interface	500	$3.0	($2.1)	($0.4)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	2.5%
15	Dickerson - Pleasant View	Line	Pepco	$0.6	($3.1)	$1.2	$5.0	$0.4	$0.9	($1.1)	($1.6)	$3.4	1.8%
16	Amos	Transformer	AEP	$0.6	($2.6)	$1.1	$4.2	($2.5)	$1.1	($3.8)	($7.4)	($3.2)	(1.7%)
17	Prairie State - W Mt. Vernon	Flowgate	MISO	($1.7)	($4.3)	($0.2)	$2.3	$0.0	($0.2)	$0.6	$0.8	$3.1	1.7%
18	Waldwick - Waldwick	Other	PSEG	$0.0	($1.4)	$1.5	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1.6%
19	Maywood - Saddlebrook	Line	PSEG	$0.0	($0.0)	$0.1	$0.2	($0.0)	$0.5	($2.6)	($3.1)	($3.0)	(1.6%)
20	Crete - St Johns	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.1	$0.6	($2.5)	($2.9)	($2.9)	(1.6%)
21	Monticello - East Winamac	Flowgate	MISO	($0.8)	($15.0)	$2.6	$16.8	$0.3	$4.4	($9.8)	($13.9)	$2.9	1.5%
22	Bagley - Graceton	Line	BGE	$1.9	($0.7)	($0.0)	$2.6	($0.2)	($0.0)	$0.4	$0.3	$2.8	1.5%
23	Hudson	Other	PSEG	$2.1	$2.2	$3.0	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1.5%
24	Huntington Junction - Huntington	Line	AP	($0.7)	($4.2)	($0.9)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	1.4%
25	Essex - Essex	Other	PSEG	$0.4	($1.3)	$0.5	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1.2%

Figure 11-2 shows the locations of the top 10 constraints affecting PJM congestion costs in the first three months of 2014.

Figure 11-2 Location of the top 10 constraints affecting PJM congestion costs: January through March of 2014[16]



16 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[17] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[18] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2013, PJM had 159 flowgates eligible for M2M (Market to Market) coordination and MISO had 265 flowgates eligible for M2M coordination.

Table 11-22 and Table 11-23 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first three months of 2014 *and the first three months of 2013, and which had the greatest congestion* cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first three months of 2014, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Rising flowgate made the most significant contribution to negative congestion.

Table 11-22 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March of 2014

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($13.9)	($78.9)	($8.4)	$56.5	$2.1	$1.3	$5.7	$6.5	$63.0	1,853	433
2	Benton Harbor - Palisades	($10.9)	($64.0)	($7.3)	$45.8	($0.2)	$0.7	($0.7)	($1.6)	$44.2	1,096	97
3	Monticello - East Winamac	($3.1)	($30.3)	$0.0	$27.2	$1.7	$3.8	($5.6)	($7.6)	$19.5	1,489	1,004
4	Cook - Palisades	($8.9)	($42.8)	($5.4)	$28.5	($1.5)	$1.6	($6.2)	($9.3)	$19.2	569	291
5	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	104
6	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
7	Oak Grove - Galesburg	($4.7)	($10.8)	$0.5	$6.6	($0.1)	($0.5)	$0.1	$0.6	$7.2	1,459	215
8	Crete - St Johns Tap	($1.4)	($6.4)	$1.3	$6.3	$0.0	$0.0	$0.0	$0.0	$6.3	571	0
9	Cumberland - Bush	($0.2)	($3.0)	$0.4	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	403	0
10	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	864	0
11	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.4)	($2.4)	0	69
12	Nelson	($2.6)	($4.9)	($0.4)	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	81	0
13	Pana North	$0.1	($0.1)	$0.1	$0.3	$0.0	$0.2	($1.8)	($1.9)	($1.6)	157	48
14	Michigan City - Laporte	($0.4)	($1.7)	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	188	0
15	Tiltonsville	$0.2	($0.7)	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	50	0
16	Whitestown - Guion	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.8	$0.9	$0.9	0	23
17	Paddock - Townline	($0.0)	($0.5)	$0.2	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	475	2
18	Kewanee - Edwards	$0.0	$0.0	$0.0	$0.0	$0.1	($0.2)	($0.8)	($0.5)	($0.5)	0	84
19	Powerton Jct - Lilly	($0.3)	($0.5)	$0.3	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	384	0
20	Bunsonville - Eugene	($1.2)	($1.5)	$0.5	$0.8	($0.1)	($0.1)	($1.2)	($1.3)	($0.5)	282	8

17 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.
18 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 11-23 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March of 2013

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($0.4)	($5.8)	$2.2	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	773	0
2	Breed - Wheatland	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.0)	($1.0)	$5.4	724	148
3	Prairie State - W Mt. Vernon	($1.7)	($4.3)	($0.2)	$2.3	$0.0	($0.2)	$0.6	$0.8	$3.1	897	692
4	Monticello - East Winamac	($0.8)	($15.0)	$2.6	$16.8	$0.3	$4.4	($9.8)	($13.9)	$2.9	998	387
5	Volunteer - Phipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
6	Oak Grove - Galesburg	($1.7)	($3.1)	($0.6)	$0.8	($0.2)	$0.1	$0.3	$0.0	$0.8	654	362
7	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.4)	($0.7)	($0.7)	0	41
8	Lanesville	($0.1)	($0.5)	$0.2	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	290	14
9	Pana North	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.5)	($0.6)	($0.6)	0	7
10	Rising	($0.4)	($1.5)	$0.6	$1.7	($0.1)	$0.1	($1.0)	($1.2)	$0.5	534	138
11	Rantoul - Rantoul Jct	($0.0)	($0.2)	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	53	0
12	Cayuga	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.3)	($0.3)	0	13
13	Reynold-Monticello	($0.1)	($0.5)	$0.2	$0.7	$0.0	$0.0	($0.5)	($0.5)	$0.2	86	51
14	Bushcin - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	5
15	Edwards - Kewanee	($0.0)	($0.1)	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	140	2
16	Bunsonville - Eugene	($0.1)	($0.2)	$0.0	$0.2	$0.0	($0.1)	($0.3)	($0.3)	($0.1)	24	91
17	Pawnee	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	39	0
18	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	34
19	Powerton Jct - Lilly	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	23
20	Cumberland - Bush	($0.1)	($1.0)	$0.1	$1.0	$0.0	$0.2	($0.8)	($1.0)	$0.0	76	50

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[19] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[20]

Table 11-24 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first three months of 2014, and which had the greatest congestion cost impact on PJM.

Table 11-24 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through March of 2014

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.5	$2.0	($0.1)	($1.6)	($1.6)	0	107
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	4

Table 11-25 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through March of 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	159
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.2	$0.0	($0.2)	($0.2)	0	9

19 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).
20 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-26 and Table 11-27 show the 500 kV constraints impacting congestion costs in PJM for the first three months of 2014 and the first three months of 2014. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-26 Regional constraints summary (By facility): January through March of 2014

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$295.7	($185.8)	($11.7)	$469.8	$31.1	$73.1	$9.1	($32.8)	$436.9	2,347	864
2	West	Interface	500	($19.9)	($282.4)	($77.9)	$184.5	$16.7	$47.7	$16.7	($14.3)	$170.2	1,022	345
3	Bedington - Black Oak	Interface	500	$20.5	($30.7)	($2.3)	$48.8	$1.4	$3.9	($1.2)	($3.6)	$45.2	841	171
4	East	Interface	500	($6.2)	($25.1)	($3.0)	$15.9	$0.3	$0.7	$0.5	$0.1	$16.0	1,217	17
5	5004/5005 Interface	Interface	500	$0.4	($17.6)	($2.7)	$15.3	$7.7	$17.5	$7.1	($2.7)	$12.6	299	313
6	Central	Interface	500	($5.0)	($13.6)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.5	297	10
7	AEP - DOM	Interface	500	$6.7	($9.7)	$3.0	$19.4	$5.5	$13.3	($9.6)	($17.3)	$2.1	756	54
8	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
9	Juniata	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
10	SENECA	Interface	500	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 11-27 Regional constraints summary (By facility): January through March of 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$62.2	($23.0)	$0.2	$85.4	$5.8	$10.8	$1.4	($3.6)	$81.8	2,012	505
2	West	Interface	500	$1.9	($8.4)	($0.6)	$9.8	$0.0	$0.0	($0.0)	($0.0)	$9.7	341	1
3	5004/5005 Interface	Interface	500	$1.0	($6.7)	($0.3)	$7.3	$1.2	$3.9	$0.4	($2.3)	$5.0	151	96
4	AEP - DOM	Interface	500	$3.0	($2.1)	($0.4)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	609	1
5	Central	Interface	500	($0.6)	($2.7)	($0.4)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	116	0
6	Bedington - Black Oak	Interface	500	$0.9	($0.7)	$0.1	$1.7	$0.0	$0.0	($0.0)	($0.0)	$1.6	105	2
7	East	Interface	500	($0.1)	($0.3)	($0.0)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.2	55	4
8	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	($0.2)	0	13
9	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
10	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6
11	Juniata	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In the first three months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first three months of 2014, financial companies received $190.8 million, an increase of $162.4 million or 571.9 percent compared to the first three months of 2013. In the first three months of 2014, physical companies paid $1,426.9 million in congestion charges, an increase of $1,212.6 million or 565.8 percent compared to the first three months of 2013.

Table 11-28 Congestion cost by type of participant: January through March of 2014

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$56.1	$65.3	($110.5)	($119.7)	($14.0)	($2.5)	($59.6)	($71.1)	$0.0	($190.8)
Physical	$277.6	($1,259.2)	$16.2	$1,553.0	$87.0	$211.4	($1.7)	($126.1)	$0.0	$1,426.9
Total	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1

Table 11-29 Congestion cost by type of participant: January through March of 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$29.4	$25.3	$30.3	$34.4	($12.3)	$1.2	($49.2)	($62.7)	$0.0	($28.4)
Physical	$55.6	($224.4)	$17.5	$297.5	$5.7	$72.1	($16.8)	($83.2)	$0.0	$214.3
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9

Marginal Losses

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system.

Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the Balancing Energy Market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

The total marginal loss cost in PJM for the first three months of 2014 was $775.9 million, which was comprised of load loss payments of -$15.1 million, generation loss credits of -$813.7 million, explicit loss costs of -$22.8 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first three months of 2014 ranged from $175.4 million in March to $414.6 million in January. Marginal loss credits increased in the first three months of 2014 by $158.0 million or 158.9 percent from the first three months of 2013, from $99.4 million to $257.4 million.

Total Marginal Loss Costs

Table 11-30 shows the total marginal loss component costs for the first three months of 2009 through 2014.

Table 11-30 Total PJM costs by loss component (Dollars (Millions)): January through March of 2009 through 2014 [21]

(Jan-Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$454	NA	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%

Total marginal loss costs for the first three months of 2009 through 2014 are shown in Table 11-31 and Table 11-32. Table 11-31 shows PJM total marginal loss costs by accounting category for the first three months of 2009 through 2014. Table 11-32 shows PJM total marginal loss costs by accounting category by market for the first three months of 2009 through 2014.

Table 11-31 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through March of 2009 through 2014

	Marginal Loss Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6
2014	($15.1)	($813.7)	($22.8)	$0.0	$775.9

21 The loss costs include net inadvertent charges.

Table 11-32 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through March of 2009 through 2014

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6
2014	($48.6)	($847.4)	$32.3	$831.1	$33.5	$33.7	($55.1)	($55.3)	$0.0	$775.9

Monthly Marginal Loss Costs

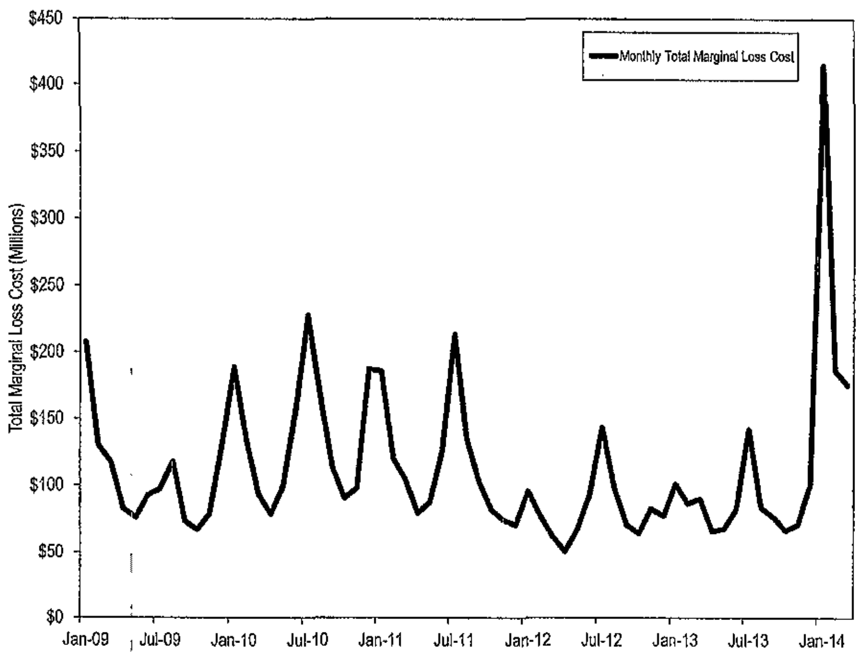
Table 11-33 shows a monthly summary of marginal loss costs by market type for the first three months of 2013 and the first three months of 2014.

Table 11-33 Monthly marginal loss costs by market (Dollars (Millions)): January through March of 2013 and 2014

	Marginal Loss Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$105.8	($4.7)	$0.0	$101.1	$431.1	($16.5)	$0.0	$414.6
Feb	$93.2	($6.5)	($0.0)	$86.7	$202.1	($16.3)	$0.0	$185.8
Mar	$97.2	($7.4)	($0.0)	$89.8	$198.0	($22.6)	($0.0)	$175.4
Total	$296.2	($18.6)	$0.0	$277.6	$831.1	($55.3)	$0.0	$775.9

Figure 11-3 shows PJM monthly marginal loss costs for January 2009 through March 2014.

Figure 11-3 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through March 2014



Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (generation energy credits less load energy payments) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 11-34 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first three months of 2009 through 2014. The total marginal loss credits increased $158.0 million in the first three months of 2014 from the first three months of 2013.

Table 11-34 Marginal loss credits (Dollars (Millions)): January through March of 2009 through 2014[22]

	Loss Credit Accounting (Millions)			
(Jan-Mar)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($218.3)	$454.0	$0.9	$236.6
2010	($207.6)	$416.6	($0.0)	$208.9
2011	($209.9)	$409.6	$0.5	$200.1
2012	($136.4)	$234.3	($0.2)	$97.7
2013	($177.9)	$277.6	($0.3)	$99.4
2014	($515.1)	$775.9	($3.3)	$257.4

22 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the Balancing Energy Market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.

The total energy cost for the first three months of 2014 was -\$515.1 million, which was comprised of load energy payments of \$28,506.4 million, generation energy credits of \$29,014.7 million, explicit energy costs of \$0.0 million and inadvertent energy charges of -\$6.9 million. The monthly energy costs for the first three months of 2014 ranged from -\$272.5 million in January to -\$119.6 million in March.

Total Energy Costs

Table 11-35 shows total energy component costs and total PJM billing, for the first three months of 2009 through 2014. The total energy component costs are net energy costs.

Table 11-35 Total PJM costs by energy component (Dollars (Millions)): January through March of 2009 through 2014[23]

(Jan-Mar)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	(\$218)	NA	\$7,515	(2.9%)
2010	(\$208)	(4.9%)	\$8,415	(2.5%)
2011	(\$210)	1.1%	\$9,584	(2.2%)
2012	(\$136)	(35.0%)	\$6,938	(2.0%)
2013	(\$178)	30.4%	\$7,762	(2.3%)
2014	(\$515)	189.6%	\$21,070	(2.4%)

Energy costs for the first three months of 2009 through 2014 are shown in Table 11-36 and Table 11-37. Table 11-36 shows PJM energy costs by accounting category for the first three months of 2009 through 2014 and Table 11-37 shows PJM energy costs by market category for the first three months of 2009 through 2014. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-35.

Table 11-36 Total PJM energy costs by accounting category (Dollars (Millions)): January through March of 2009 through 2014

	Energy Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	\$14,058.4	\$14,277.4	\$0.0	\$0.7	(\$218.3)
2010	\$13,424.4	\$13,629.0	\$0.0	(\$3.0)	(\$207.6)
2011	\$11,943.9	\$12,160.7	\$0.0	\$6.9	(\$209.9)
2012	\$8,485.4	\$8,628.7	\$0.0	\$6.8	(\$136.4)
2013	\$10,357.2	\$10,535.1	\$0.0	(\$0.0)	(\$177.9)
2014	\$28,506.4	\$29,014.7	\$0.0	(\$6.9)	(\$515.1)

23 The energy costs include net inadvertent charges.

Table 11-37 Total PJM energy costs by market category (Dollars (Millions)): January through March of 2009 through 2014

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.3	($68.3)	$0.0	$162.6	($6.9)	($515.1)

Monthly Energy Costs

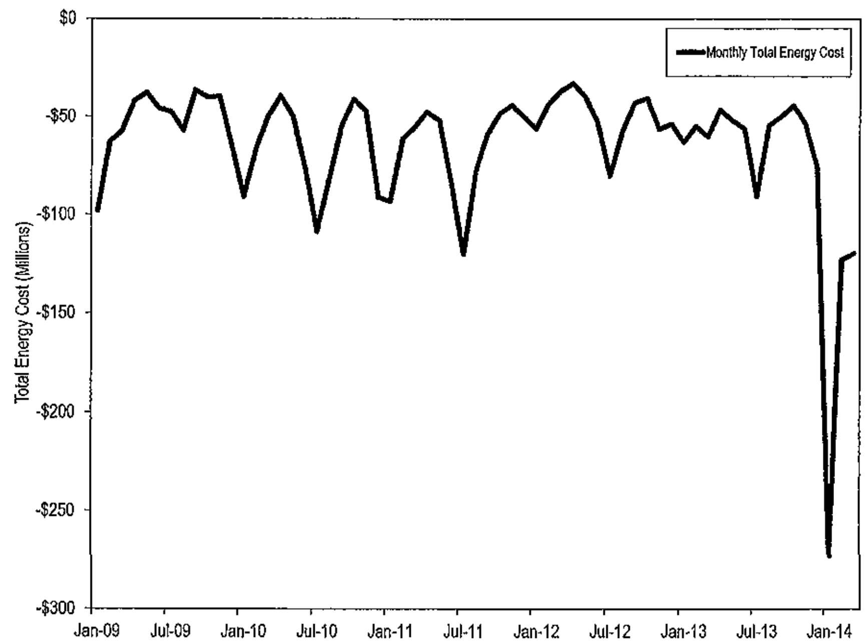
Table 11-38 shows a monthly summary of energy costs by market type for the first three months of 2013 and the first three months of 2014.

Table 11-38 Monthly energy costs by market type (Dollars (Millions)): January through March of 2013 and 2014

	Energy Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($69.2)	$5.8	$0.5	($63.0)	($339.8)	$68.3	($1.0)	($272.5)
Feb	($60.6)	$5.9	($0.1)	($54.8)	($163.7)	$43.5	($2.8)	($123.0)
Mar	($63.9)	$4.2	($0.3)	($60.0)	($167.3)	$50.8	($3.1)	($119.6)
Total	($193.7)	$15.9	($0.0)	($177.9)	($670.9)	$162.6	($6.9)	($515.1)

Figure 11-4 shows PJM monthly energy costs of January 2009 through March 2014.

Figure 11-4 PJM monthly energy costs (Dollars (Millions)): January 2009 through March 2014

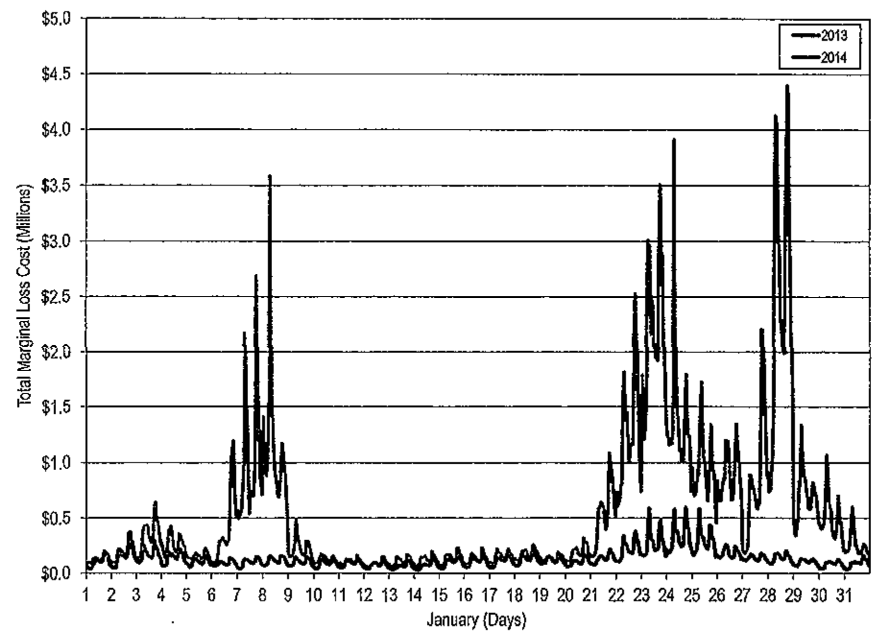


January High Load Days

The total marginal loss cost in January 2014 was 310.3 percent higher than in January 2013. Total marginal loss costs increased because of the cold weather in January, which caused higher load and prices and an increased level of losses. The loss MW in PJM increased 16.9 percent, from 1,686 GWh in January 2013 to 1,971 GWh in January 2014.

Figure 11-5 shows PJM total marginal loss cost for January of 2013 and 2014.

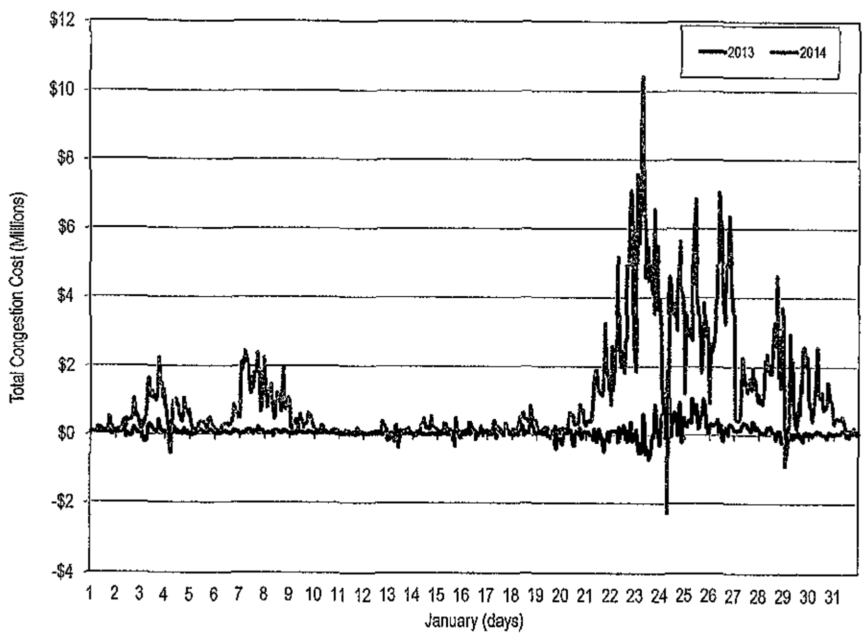
Figure 11-5 PJM total marginal loss cost (Dollars (Millions)): January of 2013 and 2014



The total congestion costs in January 2014 were 1,275.3 percent higher than in January 2013. Total congestion costs increased because of the cold weather in January, which caused higher load and prices and an increased frequency of congestion.

Figure 11-6 shows PJM total congestion cost for January of 2013 and 2014.

Figure 11-6 PJM total congestion cost (Dollars (Millions)): January of 2013 and 2014



Generation and Transmission Planning

Overview

Planned Generation and Retirements

- Planned Generation. As of March 31, 2014, 66,135 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 198,894 MW as of March 31, 2014. Of the capacity in queues, 5,973 MW, or 9.0 percent, are uprates and the rest are new generators. Wind projects account for 17,218 MW of nameplate capacity or 26.0 percent of the capacity in the queues. Combined-cycle projects account for 39,985 MW of capacity or 60.5 percent of the capacity in the queues.
- Generation Retirements. As shown in Table 12-6, 25,902.2 MW are or are planned to be retired between 2011 and 2019, with all but 2,050.5 MW retired by the end of 2015. The AEP Zone accounts for 6,024 MW, or 23.26 percent, of all MW planned for retirement from 2014 through 2019.
- Generation Mix. A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and the Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[1] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit or that requests interconnection of a merchant transmission facility must follow the process defined in the PJM tariff to obtain interconnection service.[2] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn and an accumulated backlog in completing studies.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, and Susquehanna-Roseland.

Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could

1 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones. SWMAAC consists of the BGE and Pepco control zones. See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

2 OATT Parts IV & VI.

reduce the cost of capital for transmission projects and significantly reduce total costs to customers.

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[3]
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This could result in a conflict of interest when transmission owners have generation interests.
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing. The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On March 31, 2014, 66,135 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 198,894 MW as of March 31, 2014. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1). So far, 271 MW of nameplate capacity were added in PJM in the first three months of 2014.

3 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013).

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2014

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011	5,008
2012	2,669
2013	1,127
2014 (Jan-Mar)	271

PJM Generation Queues

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all entered projects for a given queue when that queue closes. The duration of the queue period has varied over time in an attempt to improve the efficiency of the queue process. Queues A and B were each open for a year. Queues C-T were open for six months. Starting in February 2008, for Queues U-Y1, the window was reverted back to three months. In May 2012, the queue window was set back to six months, starting with Queue Y2. Queue Z2 is currently open.

All projects that have been entered in a queue will have an assigned status. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue and listed separately. A project cannot be suspended until it has reached the status of under construction. A project suspended for more than three years is subject to termination of the Interconnection Service Agreement and corresponding cancellation costs.[4]

Table 12-2 shows MW in queues by expected completion date[5] and changes in the queues from December 31, 2013 to March 31, 2014 for ongoing projects, i.e. projects with the status active, under construction or suspended. Projects that are already in service are not included here. The total MW in queues for these projects decreased by 1,164 MW, or 1.7 percent, from 67,299 MW at the beginning of 2014. The change is a result of 3,509 MW in new projects entering the queue, 4,026 MW in existing projects being withdrawn, and 435 MW going into service. The remaining difference is the result of projects adjusting their expected MW.

Table 12-2 Queue comparison by expected completion year (MW): March 31, 2014 vs. December 31, 2013[6]

	As of 12/31/2013	As of 3 /31/2014	Quarterly Change (MW)	Quarterly Change (percent)
≤ 2013	11,672	0	(11,672)	NA
2014	7,360	16,899	9,539	56.4%
2015	12,674	12,052	(622)	(5.2%)
2016	13,953	14,022	69	0.5%
2017	16,003	14,494	(1,509)	(10.4%)
2018	3,697	6,274	2,577	41.1%
2019	0	800	800	100.0%
2020	346	0	(346)	NA
2024	1,594	1,594	0	0.0%
Total	67,299	66,135	(1,164)	(1.8%)

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between January 1, 2014 and March 31, 2014. For example, 3,509 MW entered the queue in this quarter, 20 MW of which were withdrawn before the end of the quarter. Of the total 48,735 MW marked as active at the beginning of the year, 3,559 MW were withdrawn, 75 MW were suspended, and 799 MW started construction. The "In Service" column shows that 435 MW went into service in in the first quarter of 2014, in

4 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.
5 Expected completion dates are entered when the project enters the queue. They do not accurately reflect actual completion dates.
6 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

addition to the 35,532 MW of capacity that already had the status "in service" at the beginning of the year.

Table 12-3 Change in project status (MW): December 31, 2013 vs. March 31, 2014

		Status at 3/31/2014				
Status at 1/1/2013	Total at 1/1/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2014)		3,489	0	0	0	20
Active	48,735	44,114	75	799	189	3,559
Suspended	4,288	0	3,646	322	0	320
Under Construction	14,057	0	341	13,341	246	128
In Service	35,539	0	0	7	35,532	0
Withdrawn	259,254	0	0	0	0	259,254
Total at 3/31/2014		47,603	4,063	14,469	35,967	263,280

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the regional transmission expansion plan (RTEP) process and the total amount of capacity that had been included in each queue. All items in queues A-L are either in service or have been withdrawn. As of March 31, 2014, there are 66,135 MW of capacity in queues that are not yet in service of which 6.1 percent is suspended and 21.9 percent is under construction. The remaining 72.0 percent, or 47,603 MW, have not yet begun construction.

Table 12-4 Capacity in PJM queues (MW): At March 31, 2014[7]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	0	0	17,934	19,050
H Expired 31-Jan-02	0	703	0	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	0	846	886
K Expired 31-Jul-03	0	218	0	0	2,425	2,643
L Expired 31-Jan-04	0	257	0	0	4,034	4,290
M Expired 31-Jul-04	0	505	150	0	3,706	4,360
N Expired 31-Jan-05	0	2,399	38	0	8,090	10,527
O Expired 31-Jul-05	10	1,688	225	217	5,451	7,592
P Expired 31-Jan-06	43	3,255	63	210	5,068	8,638
Q Expired 31-Jul-06	105	2,498	2,244	0	9,687	14,534
R Expired 31-Jan-07	1,226	1,386	728	440	18,974	22,755
S Expired 31-Jul-07	675	3,281	559	420	12,207	17,142
T Expired 31-Jan-08	3,295	1,325	655	678	21,604	27,556
U Expired 31-Jan-09	1,915	865	692	260	29,625	33,357
V Expired 31-Jan-10	2,378	386	2,718	150	11,370	17,001
W Expired 31-Jan-11	4,599	507	1,766	1,127	16,220	24,220
X Expired 31-Jan-12	10,824	302	4,268	35	14,937	30,366
Y Expired 30-Apr-13	11,467	136	363	526	13,545	26,038
Z through 31-Mar-14	11,066	20	0	0	1,337	12,423
Total	47,603	35,967	14,469	4,063	263,280	365,382

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active as of March 31, 2014, by unit type, control zone and LDA.[8] It also shows the planned retirements for each zone. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west and includes a substantial amount of wind capacity.[9] As of March 31, 2014,

7 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
8 Unit types designated as reciprocating engines are classified here as diesel.
9 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 17,218 MW of wind resources and 1,781 MW of solar resources, the 66,135 MW currently active in the queue would be reduced to 50,051 MW.

66,135 MW of capacity were in generation request queues for construction through 2024, compared to 67,299 MW at January 1, 2014.

Table 12-5 Queue capacity by control zone and LDA (MW) at March 31, 2014[10]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,684	71	8	0	0	170	0	0	723	2,655	500
	DPL	1,223	23	0	0	0	305	20	20	279	1,870	288
	JCPL	1,445	0	0	20	0	751	0	0	0	2,216	1,095
	PECO	861	12	6	0	330	0	0	2	0	1,210	1,105
	PSEG	2,602	308	8	0	0	169	0	1	0	3,088	2,737
	EMAAC Total	7,815	413	21	20	330	1,395	20	23	1,002	11,039	5,725
SWMAAC	BGE	678	256	29	0	0	22	132	0	0	1,117	189
	Pepco	3,078	0	0	0	0	0	0	0	0	3,078	2,474
	SWMAAC Total	3,756	256	29	0	0	22	132	0	0	4,195	2,663
WMAAC	Met-Ed	800	6	0	0	50	3	0	0	0	859	652
	Penelec	919	121	39	40	0	32	0	10	711	1,871	634
	PPL	5,052	0	5	0	0	29	0	40	644	5,770	371
	WMAAC Total	6,771	127	44	40	50	64	0	50	1,354	8,500	1,657
Non-MAAC	AE	452	10	0	0	0	0	0	0	0	462	0
	AEP	6,419	40	20	35	102	116	302	34	7,941	15,009	6,024
	APS	2,464	1,418	63	62	0	40	49	0	435	4,532	3,028
	ATSI	2,634	1,015	2	0	0	14	135	0	867	4,667	2,266
	ComEd	1,150	180	19	23	0	10	0	61	4,037	5,479	1,373
	DAY	0	0	2	112	0	23	33	12	300	482	541
	DEOK	540	0	0	0	0	0	50	16	0	606	884
	DLCO	245	0	0	0	0	0	0	0	0	245	614
	Dominion	7,604	62	11	0	1,594	97	103	32	1,132	10,634	933
	EKPC	0	0	0	0	0	0	0	0	150	150	195
	Essential Power	135	0	0	0	0	0	0	0	0	135	0
	Non-MAAC Total	21,643	2,725	117	232	1,696	300	671	155	14,862	42,401	15,858
Total		39,985	3,521	212	292	2,076	1,781	823	227	17,218	66,135	25,902

A potentially significant change in the distribution of unit types within the PJM footprint is likely a combined result of the location of generation resources in the queue (Table 12-5) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. The western part of the PJM footprint is also likely to see a shift to more natural gas-fired capacity due to changes in environmental regulations and natural gas costs, but likely will maintain a larger amount of coal steam capacity than eastern zones. The replacement of older steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

10 This data includes only projects with a status of active, under-construction, or suspended.

Planned Retirements

As shown in Table 12-6, 25,902.2 MW is planned to be retired between 2011 and 2019, with all but 2,050.5 MW retired by the end of 2015. The AEP Zone accounts for 6,024 MW, or 23.26 percent, of all MW planned for deactivation from 2014 through 2019. A map of retirements between 2011 and 2019 is shown in Figure 12-1 and a detailed list of pending deactivations is shown in Table 12-7, totaling 14,740.5 MW.

Table 12-6 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,129.2
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	208.0
Planned Retirements 2014	1,870.0
Planned Retirements 2015	10,820.0
Planned Retirements Post-2015	2,050.5
Total	25,902.2

Figure 12-1 Map of PJM unit retirements: 2011 through 2019

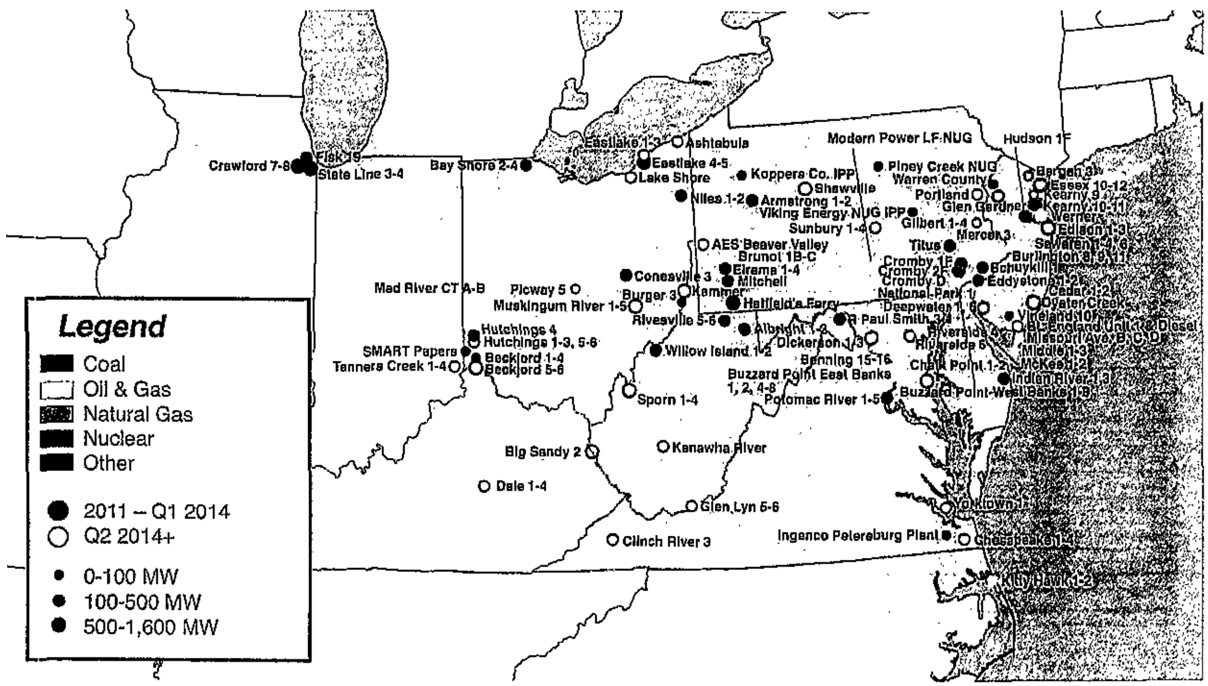


Table 12-7 Planned deactivations of PJM units, as of March 31, 2014

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
BL England 1	AECO	113.0	Coal	Steam	01-May-14
Deepwater 1, 6	AECO	158.0	Natural gas	Steam	31-May-14
Burlington 9	PSEG	184.0	Kerosene	Combustion Turbine	01-Jun-14
Portland 1-2	Met-Ed	401.0	Coal	Steam	01-Jun-14
Riverside 6	BGE	115.0	Natural gas	Combustion Turbine	01-Jun-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Walter C Beckjord 5-6	DEOK	652.0	Coal	Steam	01-Apr-15
Shawville 1-4	PENELEC	603.0	Coal	Steam	16-Apr-15
Dale 1-4	EKPC	195.0	Coal	Steam	16-Apr-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	01-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	31-May-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Eastlake 1-3	ATSI	327.0	Coal	Steam	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Lake Shore 18	ATSI	190.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Sunbury 1-4	PPL	347.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
Big Sandy 2	AEP	800.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-17
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-17
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		14,740.5			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 77.4 percent, of all MW retiring during this period are coal steam units. These units have an average age of 56.9 years, and an average size of 170.0 MW. This indicates that on average, retirements have consisted of smaller sub-critical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

Table 12-8 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	118	170.0	56.9	20,057.6	77.4%
Diesel	6	12.5	38.3	74.9	0.3%
Heavy Oil	4	68.5	57.5	274.0	1.1%
Kerosene	20	41.4	45.5	828.2	3.2%
LFG	1	10.8	7.0	10.8	0.0%
Light Oil	15	76.6	43.8	1,148.7	4.4%
Natural Gas	49	57.9	46.8	2,838.5	11.0%
Nuclear	1	614.5	50.0	614.5	2.4%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	217	119.4	51.4	25,902.2	100.0%

Actual Generation Deactivations in 2014

Table 12-9 shows unit deactivations for the first three months of 2014.[11] A total of 208.0 MW was retired during this period.

11 See PJM. "*PJM Generator Deactivations*," <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (Accessed April 05, 2014).

Table 12-9 Unit deactivations between January 1, 2014 and March 31, 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
First Energy	Mad River CTs A	25.0	Diesel	ATSI	00	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	00	09-Jan-14
Duke Energy	Walter C Beckjord 4	150.0	Coal	DEOK	00	17-Jan-14
Modern Mallard Energy	Modern Power Landfill NUG	8.0	Diesel	Met-Ed	00	03-Feb-14
Total		208.0				

Generation Mix

Currently, PJM has an installed capacity of 198,894 MW (Table 12-10) including non-derated solar and wind resources, as well as energy-only units.

Table 12-10 Existing PJM capacity: At March 31, 2014[12] (By zone and unit type (MW))

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	706	23	0	0	0	40	1,087	0	8	2,026
AEP	4,900	3,682	63	0	1,072	2,071	0	24,265	0	1,753	37,806
APS	1,129	1,215	48	0	86	0	36	5,409	27	999	8,949
ATSI	685	1,617	73	0	0	2,134	0	6,540	0	0	11,049
BGE	148	687	18	0	0	1,716	0	2,996	0	0	5,565
ComEd	2,270	7,244	100	0	0	10,474	0	5,417	5	2,454	27,964
DAY	0	1,369	48	0	0	0	1	3,180	40	0	4,637
DEOK	0	842	0	0	0	0	0	3,932	0	0	4,774
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,875	154	0	3,589	3,581	3	8,403	0	0	23,634
DPL	1,189	1,820	96	30	0	0	4	1,620	0	0	4,760
EKPC	0	774	0	0	70	0	0	1,882	0	0	2,726
EXT	664	111	0	0	0	13	0	5,484	0	0	6,271
JCPL	1,693	1,233	16	0	400	615	45	10	0	0	4,011
Met-Ed	2,051	407	41	0	19	805	0	601	0	0	3,924
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	408	46	0	513	0	0	6,794	0	931	8,690
Pepco	230	1,092	10	0	0	0	0	3,649	0	0	4,981
PPL	1,808	616	61	0	707	2,520	15	5,517	20	220	11,483
PSEG	3,091	2,838	12	0	5	3,493	107	2,050	2	0	11,598
Total	27,504	31,386	811	30	8,109	33,745	253	90,597	95	6,364	198,894

Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 30 years comprise 110,612 MW, or 55.6 percent, of the total capacity of 198,894 MW. Units older than 45 years comprise 35,359 MW, or 17.7 percent of the total capacity.

12 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 12-11 PJM capacity (MW) by age (years): at March 31, 2014

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 15	21,678	20,233	507	30	184	0	253	4,910	95	6,364	54,254
16 to 30	5,294	3,894	99	0	3,276	11,485	0	9,980	0	0	34,027
31 to 45	532	5,781	83	0	722	22,260	0	45,875	0	0	75,253
46 to 60	0	1,478	122	0	2,577	0	0	25,855	0	0	30,033
61 to 75	0	0	0	0	389	0	0	3,828	0	0	4,218
76 and over	0	0	0	0	961	0	0	149	0	0	1,110
Total	27,504	31,386	811	30	8,109	33,745	253	90,597	95	6,364	198,894

Figure 12-2 PJM capacity (MW) by age (years): at March 31, 2014

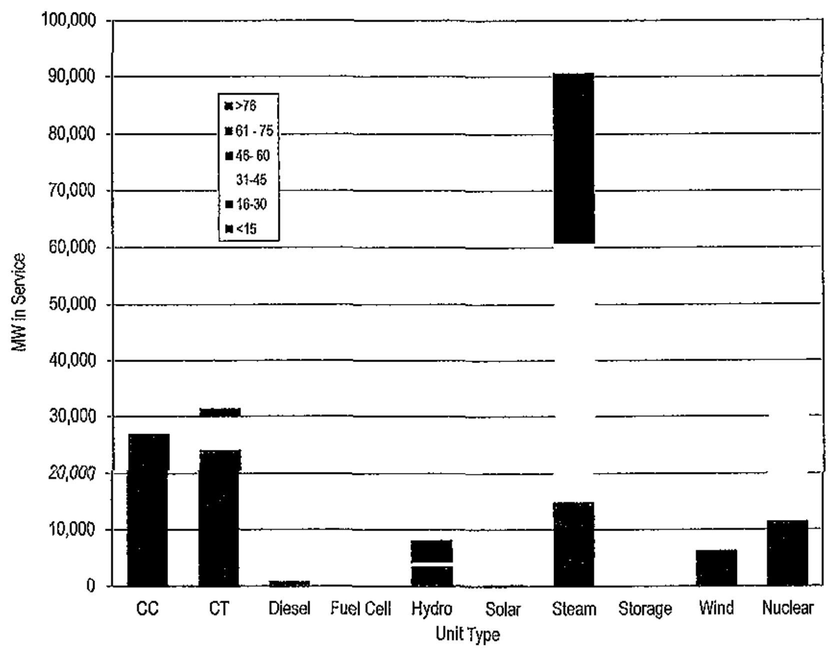


Table 12-12 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age as of March 31, 2014 retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. 63.0 percent of existing capacity in SWMAAC is currently steam; this would be reduced, by 2024, to 46.0 percent. CC and CT generators would comprise 41.8 percent of total capability in SWMAAC in 2024.

In Non-MAAC zones, 82.96 percent of all generation 40 years or older, as of March 31, 2014, is steam, primarily coal.[13] If these older coal units retire and if all queued wind MW are built as planned, by 2024, wind farms would account for 11.6 percent of total ICAP MW in Non-MAAC zones.

13 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion control zones.

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of March 31, 2014[14]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2024	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198	1.8%	9,346	27.8%	7,815	17,161	38.4%
	Combustion Turbine	3,764	34.0%	7,433	22.1%	413	7,847	17.6%
	Diesel	59	0.5%	150	0.4%	21	171	0.4%
	Fuel Cell	0	0.0%	30	0.1%	0	30	0.1%
	Hydroelectric	2,042	18.4%	2,047	6.1%	20	2,067	4.6%
	Nuclear	1,740	15.7%	8,654	25.7%	330	8,984	20.1%
	Solar	0	0.0%	198	0.6%	1,395	1,594	3.6%
	Steam	3,266	29.5%	5,746	17.1%	20	5,766	12.9%
	Storage	0	0.0%	3	0.0%	23	26	0.1%
	Wind	0	0.0%	8	0.0%	1,002	1,010	2.3%
	EMAAC Total	11,069	100.0%	33,615	100.0%	11,039	44,655	100.0%
SWMAAC	Combined Cycle	0	0.0%	378	3.6%	3,756	4,133	28.0%
	Combustion Turbine	964	19.0%	1,779	16.9%	256	2,035	13.8%
	Diesel	0	0.0%	28	0.3%	29	57	0.4%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	0	0.0%	22	22	0.1%
	Solar	0	0.0%	1,716	16.3%	0	1,716	11.6%
	Steam	4,099	81.0%	6,645	63.0%	132	6,777	46.0%
	SWMAAC Total	5,063	100.0%	10,546	100.0%	4,195	14,741	100.0%
WMAAC	Combined Cycle	0	0.0%	3,859	16.0%	6,771	10,630	32.6%
	Combustion Turbine	714	6.7%	1,430	5.9%	127	1,557	4.8%
	Diesel	46	0.4%	148	0.6%	44	192	0.6%
	Hydroelectric	887	8.4%	1,238	5.1%	40	1,278	3.9%
	Nuclear	0	0.0%	3,325	13.8%	50	3,375	10.4%
	Solar	0	0.0%	15	0.1%	64	79	0.2%
	Steam	8,974	84.5%	12,911	53.6%	0	12,911	39.6%
	Storage	0	0.0%	20	0.1%	50	70	0.2%
	Wind	0	0.0%	1,151	4.8%	1,349	2,499	7.7%
	WMAAC Total	10,620	100.0%	24,097	100.0%	8,494	32,591	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,922	10.7%	21,643	35,565	20.6%
	Combustion Turbine	1,251	2.7%	20,744	15.9%	2,725	23,468	13.6%
	Diesel	72	0.2%	485	0.4%	117	602	0.3%
	Hydroelectric	1,433	3.1%	4,824	3.7%	232	5,055	2.9%
	Nuclear	5,296	11.5%	20,049	15.3%	1,696	21,745	12.6%
	Solar	0	0.0%	40	0.0%	300	340	0.2%
	Steam	38,119	82.6%	65,295	50.0%	671	65,966	38.1%
	Storage	0	0.0%	72	0.1%	155	227	0.1%
	Wind	0	0.0%	5,206	4.0%	14,867	20,073	11.6%
	Non-MAAC Total	46,170	100.0%	130,636	100.0%	42,406	173,042	100.0%
All Areas	Total	72,922		198,894		66,135	265,029	

14 Percentages shown in Table 12-12 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Generation and Transmission Interconnection Planning Process

PJM continues to look for ways to improve the planning process, with the most recent set of changes effective in May 2012.[15] These changes include reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR).

Interconnection Study Phase

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue.

Table 12-13 shows an overview of PJM's study process. In addition to these steps, system impact and facilities studies are often redone, or retooled, when a project is withdrawn because it may affect the investments of the projects remaining in the queue.

Table 12-13 PJM generation planning process[16]

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of study (refundable deposit)	Varies	60
Schedule of Work	Upon acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Construction (only for new generation)	Upon acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

PJM's Manual 14A states that it can take up to 739 days in addition to the (unspecified) time it takes to complete the facilities study to obtain an interconnection construction service agreement (ICSA). It further states that a feasibility study should take no longer than 334 days from the day it entered the queue.[17] Manual 14B requires PJM to apply a commercial probability factor when performing each of these studies to improve the accuracy of violation estimates and consequently the study backlog.[18] The commercial probability factors are calculated based on the historical incidence of projects entering a given study phase and dropping out of the queue before going into service. PJM will employ updated values for the Y3 Impact Studies (due 3/31/2014) and Z1 Feasibility studies (due 2/14/2014). Both of these studies began in November of 2013. Table 12-14 shows these values.[19]

Table 12-14 PJM Commercial probabilities

Status	Commercial Probability (of successful completion)
Feasibility Study Completed	19%
Impact Study Completed	53%
Facilities Study Completed	100%

15 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177, <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>. (Accessed December 4, 2013).
16 Other agreements may also be required, e.g. Interconnection Construction Service Agreement (ICSA), Upgrade Construction Service Agreement (UCSA). See "PJM Manual 14C: Generation and Transmission Interconnection Process," p.29, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.
17 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," Revision 15 (April 17, 2014), p.37, <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.
18 See PJM. Manual 14B. "PJM Region Transmission Planning Process," Revision 26 (March 28, 2014), p.82, <http://www.pjm.com/~/media/documents/manuals/m14b.ashx>.
19 See PJM Planning Committee meeting presentation 'Commercial Probability, "October 10, 2013, <http://www.pjm.com/~/media/committees-groups/committees/pc/20131010/20131010-item-09-commercial-probability.ashx>.

Table 12-15 shows the milestone due when projects were actually withdrawn, for all withdrawn projects. Consistent with Table 12-14, 49.3 percent of projects withdrawn were done so before the Impact Study was completed. However, 26.8 percent of projects are withdrawn after the Facilities Study was completed, which suggests that PJM's commercial probabilities could be modified to better reflect experience.

Table 12-15 Milestone due at time of withdrawal

Milestone Due	Number of Projects Withdrawn	Percent
Feasibility	129	9.1%
Impact	573	40.2%
Facility	341	23.9%
Interconnection/Construction Service Agreement (ISA/CSA)	198	13.9%
Under Construction	184	12.9%
Total	1,425	100.0%

Table 12-16 through Table 12-19 show the time spent at various stages in the queue process, as well as the completion time for the studies performed. Table 12-16 shows that for completed projects, there is an average time of 2,934 days, or 8.0 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 628 days between entering a queue and withdrawing. It takes an average of 3.2 years to begin construction, with the worst case taking 17.4 years.

Table 12-16 Average project queue times (days) at March 31, 2014

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,160	707	39	3,630
In-Service	2,934	1,388	158	6,215
Suspended	1,940	801	882	3,846
Under Construction	1,634	751	445	6,380
Withdrawn	628	631	0	4,249

Table 12-17 presents information on the actual time in the stages of the queue for those projects not yet in service. For the 510 projects in the queue as of March 31, 2014, 45 had reached as far as the milestone of feasibility study completion and 176 were under construction.

Table 12-17 PJM generation planning summary: at March 31, 2014

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	93	18.2%	180	397
Feasibility Study	45	8.8%	421	617
Impact Study	135	26.5%	1,286	2,885
Facility Study	11	2.2%	1,404	2,268
ISA/CSA	50	9.8%	1,545	3,312
Under Construction	176	34.5%	1,344	3,536
Total	510	100.0%		

Of the 510 projects currently in the queue, the 411 projects that have been issued a feasibility study were analyzed with respect to time at each milestone of the study phase and beyond. Table 12-18 shows completion time statistics for the impact and facilities studies that have been completed for the projects currently in the queue. The days calculated are based on the date the study agreement was executed. On average, the time it took to complete the feasibility study, 186 days, was only 56 percent of PJM's estimate of 334 days. PJM Manual 14A states that a system impact study should take no longer than 120 days, which is about 50 percent of the average 238 days of actual completion time. The Manual does not provide any guidelines with respect to the time to complete a facilities study.

Table 12-18 Days to complete transmission studies

		Days to Complete		
Study	Number of Projects	Minimum	Average	Maximum
Feasibility	411	8	186	1,468
Impact	191	22	238	914
Facility	78	84	542	1,752

Table 12-18 shows that there are 269 projects currently awaiting the impact study milestone or beyond and Table 12-19 shows that 123 of those projects, totaling 17,969 MW, are delayed by a significant amount at its current milestone. For example, there are nine projects in AEP, totaling 1,509 MW, which have been waiting for the issuance of an impact study for over 200 days, one for as many as 378 days. The days in this table are based on the issue date of the last study.

Table 12-19 Study milestone delays by transmission owner and milestone

					Days Since Last Milestone		
Transmission Owner	Milestone Due	Days Exceeded	Total MW	Number of Projects	Minimum	Average	Maximum
AECO	Impact Study	200	40.0	1	391	391	391
	Facility study	600	442.5	12	734	1,143	1,838
	Completion	1,000	652.0	2	1,076	1,160	1,243
AEP	Feasibility Study	150	996.0	10	152	257	397
	Impact Study	200	1,508.5	9	207	263	378
	Facility study	600	3,927.4	13	907	1,370	1,736
	Completion	1,000	349.9	2	1,022	1,053	1,084
APS	Feasibility Study	150	1,018.0	9	152	196	316
	Impact Study	200	1,098.6	3	214	298	396
	Facility study	600	1.6	1	1,341	1,341	1,341
	Completion	1,000	188.0	2	2,380	2,599	2,818
ATSI	Feasibility Study	150	1,135.0	7	152	273	307
	Impact Study	200	35.0	1	399	399	399
	Facility study	600	484.0	4	697	912	1,035
BGE	Completion	1,000	157.0	2	1,252	1,252	1,252
ComEd	Feasibility Study	150	60.0	5	152	153	155
	Impact Study	200	80.0	5	214	220	222
	Facility study	600	1,706.3	6	1,188	1,531	1,827
	Completion	1,000	402.5	2	1,077	1,430	1,782
DAY	Facility study	600	300.0	2	1,855	1,855	1,855
DEOK	Feasibility Study	150	552.0	3	153	163	183
DLCO	Impact Study	200	205.0	1	224	224	224
Dominion	Feasibility Study	150	2,136.3	3	153	193	252
	Facility study	600	40.0	2	641	909	1,176
	Completion	1,000	3,248.5	6	1,023	1,343	2,128
DPL	Feasibility Study	150	159.5	20	152	154	187
	Impact Study	200	156.0	3	208	211	216
	Facility study	600	134.9	9	603	931	1,205
EKPC	Impact Study	200	150.3	1	321	321	321
Essential Power	Feasibility Study	150	2.0	1	230	230	230
	Impact Study	200	135.0	1	221	221	221
JCPL	Feasibility Study	150	20.0	1	215	215	215
	Impact Study	200	20.0	1	398	398	398
	Facility study	600	17.0	2	916	961	1,006
Met-Ed	Feasibility Study	150	6.0	1	152	152	152
	Facility study	600	38.0	2	1,097	1,432	1,766
PECO	Feasibility Study	150	2.0	1	152	152	152
	Impact Study	200	825.5	2	214	272	329
	Facility study	600	334.0	5	822	932	1,250
PENELEC	Feasibility Study	150	728.7	10	152	179	243
	Impact Study	200	187.4	3	214	278	397
	Facility study	600	172.5	3	1,097	1,162	1,201
	Completion	1,000	5.4	1	1,720	1,720	1,720
Pepco	Feasibility Study	150	64.5	1	215	215	215
	Completion	1,000	550.0	2	1,357	1,357	1,357
PPL	Feasibility Study	150	401.0	2	152	153	153
	Impact Study	200	82.0	2	208	209	209
PSEG	Feasibility Study	150	1,125.9	8	151	161	187
	Impact Study	200	294.0	10	209	214	216

Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the extra high voltage (EHV) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, and Susquehanna-Roseland.

The Mount Storm-Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability in its service areas. As of mid-February 2014, construction is ahead of schedule. All structure foundations are complete. Approximately 91 percent of the structures have been erected and more than 77 percent of the line is complete at this time. Rehab work is 69 percent complete and will be done by the end of the year.[20] Dominion has completed 75 miles of the line rebuild. Dominion will complete construction and energize its portion of the project by May 2014, one year ahead of schedule. Dominion is currently meeting with First Energy to develop energization and testing procedures. Potomac Edison is targeting an in-service date of 06/01/2014 for its portion.

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. The status as of March 31, 2014, is that

20 See Dominion. "Mt. Storm-Doubs 500kV Rebuild Project," <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (March 31, 2014).

the transmission line engineering is ninety percent complete, with a restart scheduled in 2015, and the substation engineering is forty percent complete, with a restart scheduled in August 2015-October 2016. Below grade construction of the sub-station is scheduled to be completed by September 2016, and above grade, relay/control construction, is planned for October 2016-June 2017. Transmission foundations are now planned for fall 2015.

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland will be a new 500 kV transmission line connecting the Susquehanna – Lackawanna – Hopatcong – Roseland buses. PPL is responsible for the first two legs. Their expectations as of March 31, 2014, are for the Susquehanna-Lackawanna portion to be in-service by December 2014, and the Lackawanna – Hopatcong portion by June, 2015. The remaining leg, Hopatcong – Roseland, is being executed by PSE&G and is anticipated to be in-service by June 2015. Engineering and design of the transmission and substations are over 95 percent complete for both parties. PSE&G's construction status is as follows. Foundation installation is 85 percent complete, tower demolition is 70 percent complete, tower erection is 67 percent complete, and conductor installation is 64 percent complete. PPL continues on schedule with existing Tower Demolition, foundation installation, and new structure erection.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and which creates the funds available to offset congestion costs in an LMP market.[2]

The *2014 Quarterly State of the Market Report for PJM: January through March*, focuses on the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period, covering January 1, 2014, through March 31, 2014.

Table 13-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259-62,260 & n. 123.

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and over sells FTRs. FTR funding levels are reduced as a result of these and other factors.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the first ten months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, total participant FTR sell offers were 4,990,310 MW, up from 4,627,335 MW for the same period during the 2012 to 2013 planning period.
- **Demand.** The total FTR buy bids from the first ten months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 23.5 percent from 18,299,865 MW for the same time period of the prior planning period, to 22,593,834 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 77.8 percent of prevailing flow and 87.4 percent of counter flow FTRs for January through March of 2014.

Financial entities owned 68.0 percent of all prevailing and counter flow FTRs, including 58.3 percent of all prevailing flow FTRs and 84.7 percent of all counter flow FTRs during January through March 2014.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $531,678 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.
- **Credit Issues.** People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[3]

  Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. These defaults were not necessarily related to FTR positions.

3 *See* Default Allocation Assessment, OATT Section 15.2.2

Market Performance

- **Volume.** For the first ten months of the 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 3,055,950 MW (13.5 percent) of FTR buy bids and 1,003,321 MW (20.1 percent) of FTR sell offers.
- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2013 to 2014 planning period was $0.10, down from $0.12 per MW in the 2012 to 2013 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $8.3 million in net revenue for all FTRs for the first ten months of the 2013 to 2014 planning period, down from $21.7 million for the same time period in the 2012 to 2013 planning period.
- **Revenue Adequacy.** FTRs were paid at 74.5 percent of the target allocation level for the first ten months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,693.5 million of FTR revenues during the first ten months of the 2013 to 2014 planning period and $614.0 million during the entire 2012 to 2013 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the Western Hub.

  Target allocations values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs.
- ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 97.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2013 to 2014

planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $677.5 million in profits for physical entities, of which $309.5 million was from self-scheduled FTRs, and $442.2 million for financial entities. Not every FTR was profitable. FTR profits were high for the first three months of 2014 due in large part to very high January congestion prices and higher than normal congestion prices in February and March.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the annual ARR allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the annual ARR allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the first ten months of the 2013 to 2014 planning period PJM allocated a total of 4,527.4 MW of residual ARRs with a total target allocation of $1,783,870.
- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 53,988 MW of ARRs associated with approximately $309,200 of revenue that were reassigned for the first ten months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first ten months of the 2013 to 2014 planning period, the ARR target allocations were $432.7 million while PJM collected $662.3 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $587.0 million while PJM collected $653.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first ten months of the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.

- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, *with the creation of ARRs, do not have the* right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested. One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system as a hedge against congestion and pay for balancing congestion in order to increase the payout to holders of FTRs who are not loads.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period, the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June

2013, the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM monthly is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real-time markets, including reactive interfaces, which directly results in differences in congestion between day - ahead and real-time markets; differences in day-ahead and real-time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day-ahead and real-time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, *PJM should reduce the number of FTRs sold.*

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths, subject to revenue availability. This value, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The value of an *FTR reflects the difference in congestion prices rather than the difference in* LMPs, which includes both congestion and marginal losses.

Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation is a cap on what FTR holders can receive. Revenues above that level on individual FTR paths are used to fund FTRs on paths which received less than their target allocations. Available revenue to pay FTR holders is based on the amount of day-ahead and balancing congestion collected, along with Market to Market payments, excess ARR revenues available at the end of a month and any charges made to day-ahead operating reserves.

FTR funding is not on a path specific basis or on a time specific basis. There are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on *their pro rata share of total net positive* FTR *target allocations, excluding any* charge to FTR holders with a net negative FTR position for the planning year.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. Revenues to fund FTRs come from both day-ahead congestion charges on the transmission system and balancing congestion charges. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self-scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates an Annual FTR Auction for all participants. In addition, PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, which allows participants to buy and sell residual transmission capability. PJM also runs a Long Term FTR Auction for the following three consecutive planning years. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

FTR buy bids and sell offers may be made as obligations or options and as any of the three classes. FTR self-scheduled bids are available only as obligations and 24-hour class, consistent with the associated ARRs, and only in the Annual FTR Auction.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[4] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction.

Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included in the model, while known outages of five days or more are included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[5]

But the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR.

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Existing FTRs are modeled as fixed injections and withdrawals. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining

4 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 38.
5 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 55.

in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak and off peak products.[6]

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Buy Bids

The total FTR buy bids in the 2013 to 2014 Annual FTR Auction were 3,274,373 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period were 19,685,688 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-2 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through March 2014 by trade type, organization type and FTR direction. Financial entities purchased 77.8 percent of prevailing flow and 87.4 percent of counter flow FTRs for the year, with the result that financial entities purchased 81.4 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through March 2014.

Table 13-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through March 2014

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	22.2%	12.6%	18.6%
	Financial	77.8%	87.4%	81.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	31.6%	36.8%	32.4%
	Financial	68.4%	63.2%	67.6%
	Total	100.0%	100.0%	100.0%

Table 13-3 presents the daily net position ownership for all FTRs for January through March 2014, by FTR direction.

Table 13-3 Daily FTR net position ownership by FTR direction: January through March 2014

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	41.7%	15.3%	32.0%
Financial	58.3%	84.7%	68.0%
Total	100.0%	100.0%	100.0%

6 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 39.

Market Behavior

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real-time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 13-1 demonstrates the FTR forfeiture rule for INCs and DECs. The INC or DEC distribution factor (dfax) is compared to the largest impact withdrawal or injection dfax. If the absolute difference between the virtual bid and its counterpart is greater than or equal to 75 percent, the virtual bid is considered for forfeiture. This is the metric in the rule which defines the impact of the virtual bid on the constraint.

In the first part of the example in Figure 13-1, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfaxes is -0.75 (0.25 minus -0.5). The absolute value is 0.75. In the second part of the example in, the DEC has dfax of 0.5 and the maximum injection dfax on the constraint is -0.25. The difference between the two dfaxes is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-1 Illustration of INC/DEC FTR forfeiture rule

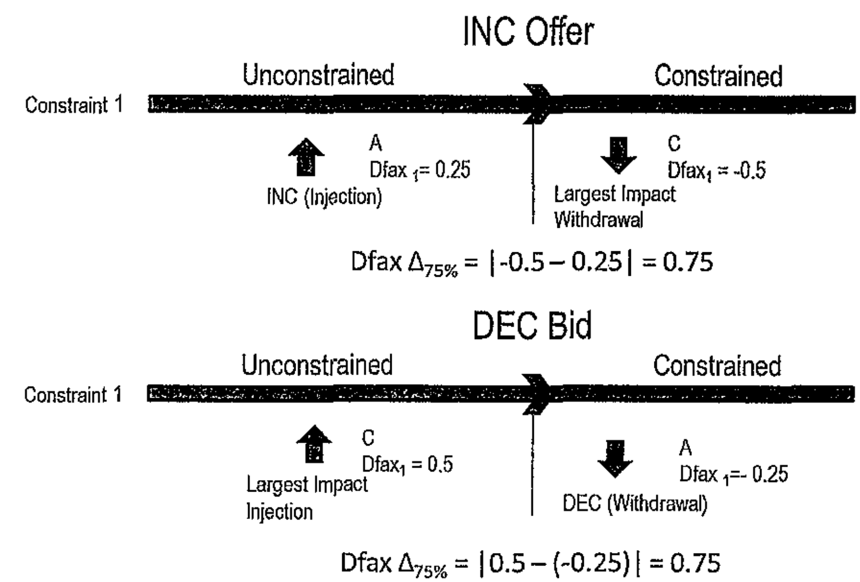


Figure 13-2 shows the FTR forfeitures values for both physical and financial participants for each month of June 2010 through March 2014. Currently, FTRs that alleviate a constraint are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2012 to 2013 planning period were $1.1 million (0.09 percent of total FTR target allocations).

Figure 13-2 Monthly FTR forfeitures for physical and financial participants: June 2010 through March 2014

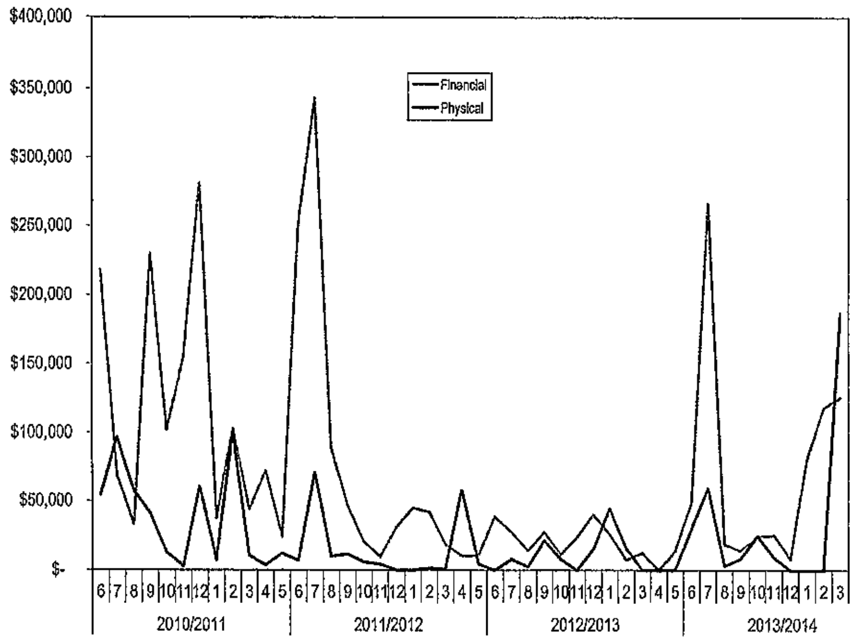
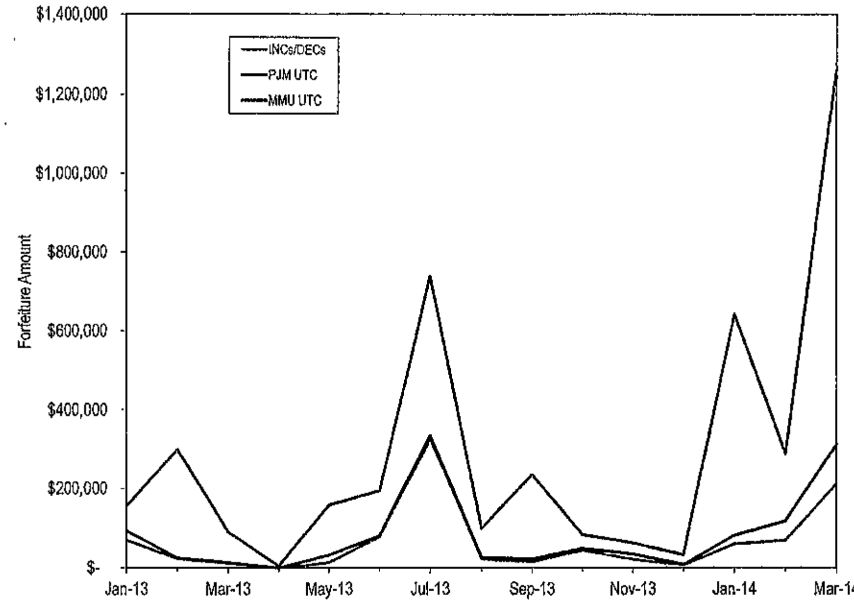


Figure 13-3 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through March 2014. The method proposed by PJM for calculating forfeitures associated with UTCs was implemented on September 1, 2013, and for each month thereafter. UTC forfeitures before September 2013 were not billed, but are included to illustrate the impact of the different methods of calculating forfeitures. The UTC curves include all forfeitures for the month associated with INCs, DECs and UTCs.

Figure 13-3 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through March 2014



Credit Issues

People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with the FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[7]

Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

Volume

In an effort to reduce FTR underfunding caused by forced Stage 1A infeasibilities, PJM may use reduced capability limits instead of the increased Stage 1A capability limits in FTR auctions. These capability limits may be reduced if ARR funding is not impacted, all requested self-scheduled FTRs clear and net FTR Auction revenue is positive. If the normal capability limit cannot be reached due to infeasibilities then FTR Auction capability reductions are undertaken pro-rata based on the MWs of Stage 1A infeasibility. Reducing capability limits will reduce the number of oversold FTR facilities due to forced Stage 1A infeasibilities and reduce underfunding caused by these ARR infeasibilities. The downside to this strategy is that there will be less FTRs for sale in the FTR Auctions, therefore, less auction revenue will be collected to pay ARR holders.

Also in an effort to reduce FTR underfunding, PJM implemented a new rule stating that PJM may model normal capability limits on facilities which are infeasible due to modeled transmission outages in Monthly Balance of Planning Period FTR Auctions. The capability of these facilities may be reduced if ARR target allocations are fully funded and net auction revenues are greater than zero. The results of this action should be an increased feasibility of the FTR model and a reduced risk of FTR underfunding, but will lead to a reduction in FTR Auction revenue due to a lower capability.

7 See Default Allocation Assessment. OATT Section 15.2.2

Table 13-4 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2012 to 2013 planning period and the first ten months of the 2013 to 2014 planning period. There were 18,551,508 MW of FTR buy bid obligations and 3,759,285 MW of FTR sell offer obligations for all bidding periods in the first ten months of the 2013 to 2014 planning period. The monthly balance of planning period auctions cleared 2,935,257 MW (15.8 percent) of FTR buy bid obligations and 581,067 MW (15.5 percent) of FTR sell offer obligations.

There were 4,042,327 MW of FTR buy bid options and 1,231,025 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2013 to 2014 planning period. The monthly auctions cleared 120,693 (3.0 percent) of FTR buy bid options, and 422,254 MW (34.3 percent) of FTR sell offers.

Table 13-4 Monthly Balance of Planning Period FTR Auction market volume: January through March 2014

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-14	Obligations	Buy bids	235,126	1,793,756	257,472	14.4%	1,536,283	85.6%
		Sell offers	103,912	286,684	45,850	16.0%	240,834	84.0%
	Options	Buy bids	6,536	298,300	7,805	2.6%	290,495	97.4%
		Sell offers	14,893	92,294	34,143	37.0%	58,151	63.0%
Feb-14	Obligations	Buy bids	235,697	1,578,788	239,877	15.2%	1,338,911	84.8%
		Sell offers	122,726	315,024	53,406	17.0%	261,619	83.0%
	Options	Buy bids	9,970	400,903	5,716	1.4%	395,187	98.6%
		Sell offers	12,801	75,859	35,021	46.2%	40,837	53.8%
Mar-14	Obligations	Buy bids	208,029	1,544,652	251,291	16.3%	1,293,361	83.7%
		Sell offers	107,355	274,653	50,275	18.3%	224,378	81.7%
	Options	Buy bids	11,027	373,373	10,379	2.8%	362,994	97.2%
		Sell offers	13,120	83,295	41,895	50.3%	41,400	49.7%
2012/2013*	Obligations	Buy bids	2,255,105	12,956,832	2,171,751	16.8%	10,785,081	83.2%
		Sell offers	1,080,775	3,922,225	468,426	11.9%	3,453,798	88.1%
	Options	Buy bids	103,926	6,728,856	74,889	1.1%	6,653,967	98.9%
		Sell offers	149,274	1,088,211	268,684	24.7%	819,527	75.3%
2013/2014**	Obligations	Buy bids	2,699,902	18,551,508	2,935,257	15.8%	15,616,251	84.2%
		Sell offers	1,369,084	3,759,285	581,067	15.5%	3,178,218	84.5%
	Options	Buy bids	86,568	4,042,327	120,693	3.0%	3,921,634	97.0%
		Sell offers	175,733	1,231,025	422,254	34.3%	808,771	65.7%

* Shows Twelve Months for 2012/2013; ** Shows ten months ended 31-Mar-14 for 2013/2014

Table 13-5 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for January through March 2013 is 257,513.3 MW. The average monthly cleared volume for January through March 2013 was 179,654.4 MW.

Table 13-5 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through March 2014

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-14	Bid	955,235	415,803	335,298				385,720	2,092,055
	Cleared	171,036	42,816	21,423				30,002	265,277
Feb-14	Bid	960,803	349,289	340,651				328,949	1,979,691
	Cleared	158,160	30,891	23,446				33,096	245,593
Mar-14	Bid	1,021,453	362,479	380,157				153,936	1,918,025
	Cleared	184,026	38,011	30,016				9,616	261,670

Figure 13-4 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through March 2014, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with an accompanying rise in the share of Annual FTRs.

Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through March 2014

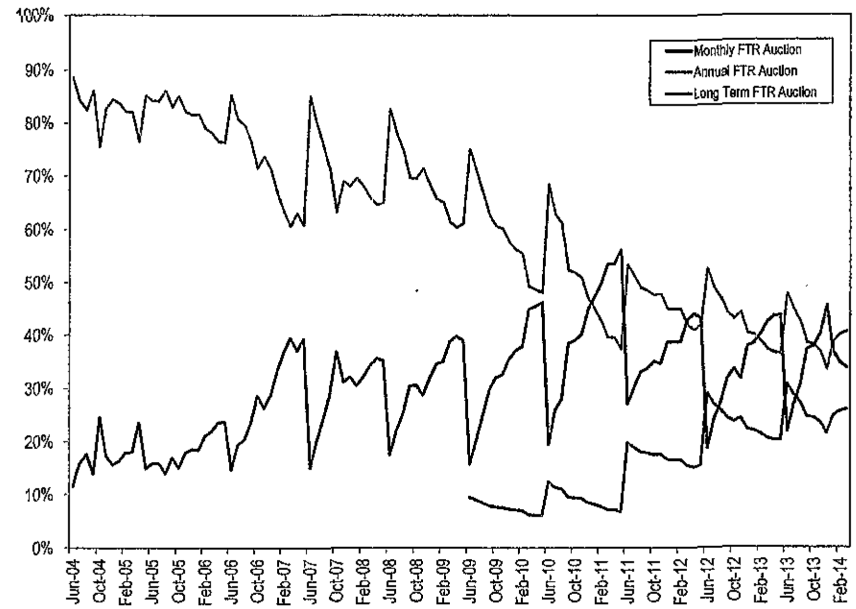


Table 13-6 provides the secondary bilateral FTR market volume for the entire 2012 to 2013 and 2013 to 2014 planning periods.

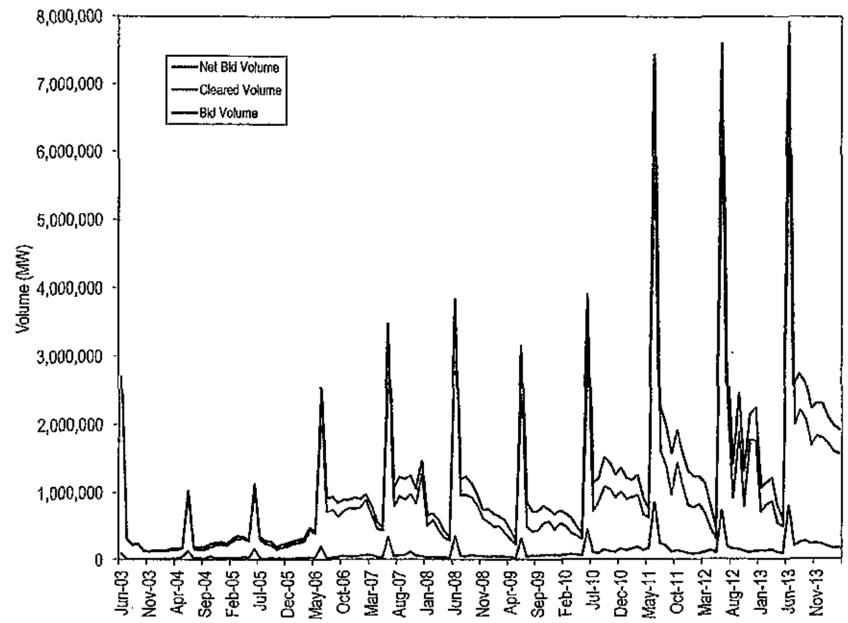
Table 13-6 Secondary bilateral FTR market volume: Planning periods 2012 to 2013 and 2013 to 2014[8]

Planning Period	Hedge Type	Class Type	Volume (MW)
2012/2013	Obligation	24-Hour	95
		On Peak	137
		Off Peak	60
		Total	292
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0
2013/2014	Obligation	24-Hour	110
		On Peak	41,665
		Off Peak	34,338
		Total	76,114
	Option	24-Hour	0
		On Peak	9,724
		Off Peak	914
		Total	10,638

Figure 13-5 shows the FTR bid, cleared and net bid volume from June 2003 through March 2014 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume is the volume of FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers, excluding sell offers. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

8 The 2013 to 2014 planning period covers bilateral FTRs that are effective for any time between June 1, 2013 through March 31, 2013, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through March 2014



Price

Table 13-7 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2014 through March 2014. For example, for the January 2014 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2013 Monthly Balance of Planning Period FTR Auction.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through March 2014 was $0.10 per MW, down from $0.12 per MW in the same time last year.

Table 13-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through March 2014

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-14	$0.11	$0.12	$0.08				$0.05	$0.09
Feb-14	$0.31	$0.22	$0.10				$0.13	$0.22
Mar-14	$0.19	$0.18	$0.17				$0.17	$0.19

Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but the ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 13-8 lists FTR profits by organization type and FTR direction for the period from January through March 2014. FTR profits are the sum of the daily FTR credits, including for self-scheduled FTRs, minus the daily FTR auction costs for each FTR held by an organization. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days, but self-scheduled FTRs have zero cost. FTRs were profitable overall, with $677.5 million in profits for physical entities, of which $309.5 million was from self-scheduled FTRs, and $442.2 million for financial entities.

Table 13-8 FTR profits by organization type and FTR direction: January through March 2014

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$448,081,252	$311,505,599	($80,050,540)	($2,036,484)	$677,499,826
Financial	$498,229,616	NA	($56,032,809)	NA	$442,196,807
Total	$946,310,868	$311,505,599	($136,083,349)	($2,036,484)	$1,119,696,634

Table 13-9 lists the monthly FTR profits in the first three months of 2014 by organization type.

Table 13-9 Monthly FTR profits by organization type: January through March 2014

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$258,854,352	$185,979,150	$293,745,778	$738,579,281
Feb	$53,532,036	$40,575,599	$52,161,164	$146,268,800
Mar	$55,644,323	$82,914,366	$96,289,865	$234,848,553
Total	$368,030,712	$309,469,114	$442,196,807	$1,119,696,634

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-10 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through March 2014. The Monthly Balance of Planning Period FTR Auction netted $8.3 million in revenue, with buyers paying $164.9 million and sellers receiving $156.6 million for the first ten months of the 2013 to 2014 planning period. Net revenues were up 88.6 percent, with a net revenue of $8.3 million for the first ten months of the 2013 to 2014 planning period. For the entire 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions netted $23.8 million in revenue with buyers paying $127.7 million and sellers receiving $22.1 million.

Table 13-10 Monthly Balance of Planning Period FTR Auction revenue: January through March 2014

Monthly Auction	Type	Trade Type	Class Type			
			24-Hour	On Peak	Off Peak	All
Jan-14	Obligations	Buy bids	$538,610	$6,544,992	$3,406,763	$10,490,364
		Sell offers	$255,974	$3,772,022	$2,170,525	$6,198,521
	Options	Buy bids	$0	$495,869	$277,203	$773,072
		Sell offers	$0	$2,607,255	$2,450,896	$5,058,152
Feb-14	Obligations	Buy bids	$772,337	$13,639,753	$8,949,253	$23,361,343
		Sell offers	$861,314	$8,562,236	$6,040,336	$15,463,885
	Options	Buy bids	$0	$530,102	$628,647	$1,158,749
		Sell offers	$7,752	$4,398,077	$3,362,318	$7,768,147
Mar-14	Obligations	Buy bids	$1,279,408	$9,929,162	$6,943,023	$18,151,593
		Sell offers	$674,564	$6,152,784	$3,794,533	$10,621,881
	Options	Buy bids	$0	$959,329	$699,358	$1,658,688
		Sell offers	$13,013	$3,653,094	$2,937,076	$6,603,182
2012/2013*	Obligations	Buy bids	$67,116	$76,349,386	$43,832,157	$120,248,659
		Sell offers	$4,731,328	$40,127,400	$18,982,130	$63,840,858
	Options	Buy bids	$152,160	$4,512,768	$2,793,076	$7,458,004
		Sell offers	$313,760	$22,240,204	$17,444,010	$39,997,974
	Total		($4,825,812)	$18,494,550	$10,199,092	$23,867,830
2013/2014**	Obligations	Buy bids	$7,896,252	$89,855,619	$56,623,143	$154,375,015
		Sell offers	$9,197,517	$52,478,321	$36,383,288	$98,059,126
	Options	Buy bids	$11,046	$5,788,586	$4,718,132	$10,517,764
		Sell offers	$20,765	$32,411,503	$26,091,820	$58,524,088
	Total		($1,310,983)	$10,754,381	($1,133,833)	$8,309,565

* Shows Twelve Months; ** Shows ten months ended 31-Mar-2014 for 2013/2014

Figure 13-6 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period. The top 10 positive revenue producing FTR sources accounted for $56.4 million of the total revenue of $8.2 million paid in the auction, they also comprised 4.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$19.8 million of revenue and constituted 3.0 percent of all FTRs bought in the auction.

Figure 13-6 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through March 31, 2014

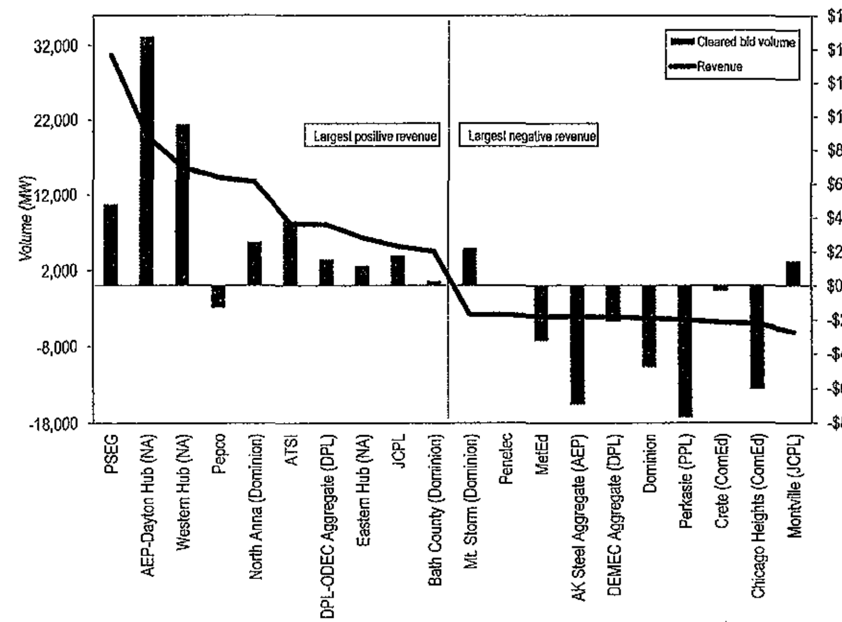


Figure 13-7 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period through March 31, 2014. The top 10 positive revenue producing FTR sources accounted for $50.8 million of the total revenue of $8.3 million paid in the auction, they also comprised 4.9 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$15.2 million of revenue and constituted 0.3 percent of all FTRs bought in the auction.

Figure 13-7 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through March 31, 2014

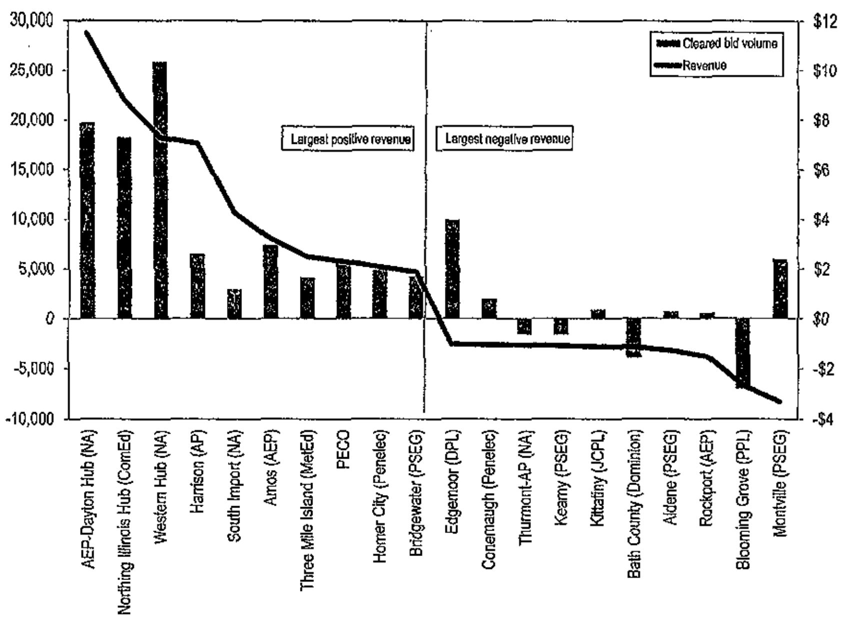
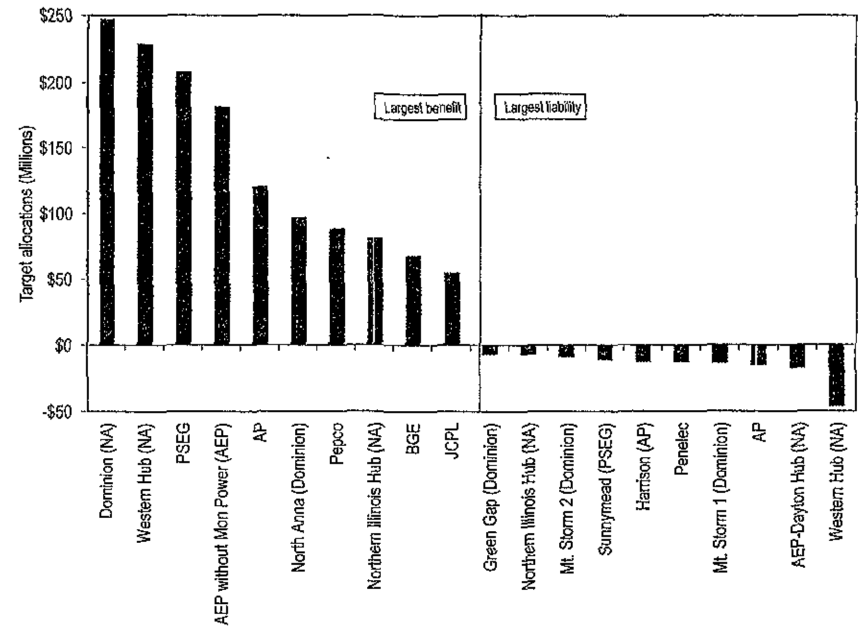


Figure 13-8 Ten largest positive and negative FTR target allocations summed by sink: 2013 to 2014 planning period through March 31, 2014

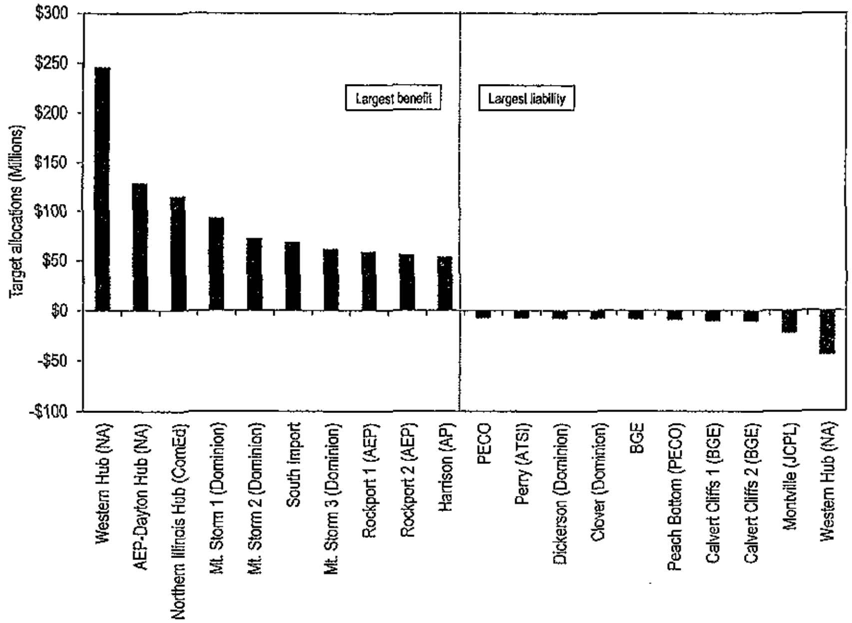


FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the first ten months of the 2013 to 2014 planning. Figure 13-8 shows the ten largest positive and negative FTR target allocations, summed by sink, for the first ten months of the 2013 to 2014 planning period. The top 10 sinks that produced financial benefit accounted for 22.5 percent of total positive target allocations during the 2013 to 2014 planning period with Dominion accounting for 4.0 percent of all positive target allocations. The top 10 sinks that created liability accounted for 9.8 percent of total negative target allocations with the Western Hub accounting for 2.9 percent of all negative target allocations.

Figure 13-9 shows the ten largest positive and negative FTR target allocations, summed by source, for the first ten months of the 2013 to 2014 planning period. The top 10 sources with a positive target allocation accounted for 15.5 percent of total positive target allocations with the Western Hub accounting for 4.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 8.8 percent of all negative target allocations, with the Western Hub accounting for 2.8 percent.

Figure 13-9 Ten largest positive and negative FTR target allocations summed by source: 2013 to 2014 planning period through March 31, 2014



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[9] That is the source of the congestion revenue to pay holders of ARRs and FTRs. In general, FTR revenue adequacy exists when the sum of congestion credits is equal to or greater than the sum of congestion across the positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues to the total target allocations across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. The adequacy of FTRs as an offset against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability or purchase of FTRs.

FTRs are paid each month from congestion revenues, both day-ahead and balancing, FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets, and net negative congestion.[10] FTR revenues also include ARR excess, which is the difference between ARR target allocations and FTR auction revenues, and negative FTR target allocations, which is an income for the FTR market from FTRs with a negative target allocation. Competing use revenues are based on the Unscheduled

9 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

10 Hourly congestion revenues may be negative.

Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-11 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates (M2M flowgates) in MISO and NYISO whose operating limits are respected by PJM.[11]

In the first three months of 2014, the market to market operations resulted in NYISO, MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

For the 2012 to 2013 planning period, PJM paid MISO and NYISO a combined $40.3 million for the redispatch on the designated M2M flowgates, and for the first ten months of the 2013 to 2014 planning period PJM has paid MISO and NYISO a combined $2.3 million. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any previous PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

11 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

FTRs were paid at 74.5 percent of the target allocation level for the first ten months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,754.3 million of FTR revenues during the first ten months of the 2013 to 2014 planning period, and $534.3 million during the first ten months of the 2012 to 2013 planning period, a 228.3 percent decrease. For the first ten months of the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the AEP-Dayton Hub and the Western Hub.

Table 13-11 presents the PJM FTR revenue detail for the 2012 to 2013 planning period and the first ten months of the 2013 to 2014 planning period.

Table 13-11 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

Accounting Element	2012/2013	2013/2014*
ARR information		
ARR target allocations	$587.0	$432.7
FTR auction revenue	$653.6	$662.3
ARR excess	$66.7	$58.0
FTR targets		
Positive target allocations	$992.9	$2,384.3
Negative target allocations	($86.1)	($110.5)
FTR target allocations	$906.8	$2,273.9
Adjustments:		
Adjustments to FTR target allocations	($1.0)	($0.7)
Total FTR targets	$905.8	$2,273.2
FTR revenues		
ARR excess	$66.7	$58.0
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($90.6)	($50.2)
Hourly congestion revenue	$668.4	$1,715.5
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($41.1)	($39.1)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.0)	$0.0
Total FTR revenues	$601.9	$1,684.2
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$12.1	$9.2
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$614.0	$1,693.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$614.0	$1,693.5
Remaining deficiency	$292.3	$579.7

* Shows ten months ended 31-Mar-14

Unallocated Congestion Charges

When congestion revenue at the end of an hour is negative, target allocations in that hour are set to zero, and there is a congestion liability for that hour. At the end of the month, if excess ARR revenue and excess congestion from other hours and months are not adequate to offset the sum of these hourly differences, day-ahead operating reserves are charged the unallocated congestion charges so that the total congestion for the month is not less than zero. This charge is applied retroactively at the end of the month as additional day-ahead operating reserves charges and is never credited back to day-ahead operating reserves in the case of excess congestion. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation and there was not enough excess during the month to pay the difference. From 2010 through May 31, 2012, these charges were only made three times, for a total of $7.3 million. However, in the 2012 to 2013 planning period these charges were made in five months for a total of $12.1 million in just one planning period.

Table 13-12 shows the monthly unallocated congestion charges made to day-ahead operating reserves for the 2012 to 2013 planning period and the 2013 to 2014 planning period through March. Months with no unallocated congestion are excluded from the table.[12]

Table 13-12 Unallocated congestion charges: Planning period 2012 to 2013 to 2013 and 2014

Period	Charge
Oct-12	$794,752
Dec-12	$193,429
Jan-13	$5,233,445
Mar-13	$701,303
May-13	$5,210,739
Jun-13	$2,828,660
Sep-13	$6,411,602
2012/2013	$12,133,668
2013/2014	$9,240,262

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and are defined to be the revenue required to compensate FTR holders for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-13 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess

12 See Section 4, "Energy Uplift" at "Energy Uplift Charges" for the impact of Unallocated Congestion Charges on Operating Reserve rates.

congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 13-13 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-13 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2012 to 2013 and 2013 to 2014

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-12	$58.5	$62.9	92.9%	$58.5	93.0%	($4.4)
Jul-12	$71.3	$80.0	88.9%	$71.3	88.9%	($8.8)
Aug-12	$54.1	$55.4	97.1%	$54.1	97.3%	($1.3)
Sep-12	$38.7	$82.5	46.7%	$38.7	46.8%	($43.8)
Oct-12	$24.3	$58.2	41.8%	$25.1	42.7%	($33.1)
Nov-12	$52.0	$59.6	87.2%	$52.0	87.3%	($7.5)
Dec-12	$36.3	$50.1	72.2%	$36.5	72.5%	($13.6)
Jan-13	$63.4	$120.3	53.4%	$68.6	56.5%	($51.7)
Feb-13	$77.2	$128.1	60.5%	$77.2	60.2%	($50.9)
Mar-13	$51.7	$70.7	73.2%	$52.4	74.2%	($18.2)
Apr-13	$32.7	$47.4	69.4%	$32.7	69.0%	($14.7)
May-13	$41.8	$90.7	46.1%	$47.0	51.9%	($43.7)
Summary for Planning Period 2012 to 2013						
Total	$601.9	$905.8		$614.0	67.8%	($291.8)
Jun-13	$61.3	$81.9	74.7%	$64.1	78.2%	($17.8)
Jul-13	$113.5	$128.3	88.3%	$113.5	88.5%	($14.7)
Aug-13	$43.1	$45.8	94.0%	$43.1	94.0%	($2.7)
Sep-13	$60.3	$116.0	52.0%	$66.7	57.5%	($49.3)
Oct-13	$47.4	$63.9	74.0%	$47.4	74.1%	($16.6)
Nov-13	$44.7	$66.9	66.9%	$44.7	66.9%	($22.1)
Dec-13	$85.0	$115.9	73.3%	$85.0	73.3%	($31.0)
Jan-14	$815.8	$1,044.0	78.1%	$815.8	78.1%	($228.2)
Feb-14	$167.7	$243.2	68.9%	$167.7	68.9%	($75.5)
Mar-14	$245.5	$367.3	66.8%	$245.5	66.8%	($121.8)
Summary for Planning Period 2013 to 2014						
Total	$1,684.2	$2,273.2		$1,693.5	74.5%	($579.8)

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through March 2014. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 13-10 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratios for months in the 2013 to 2014 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 13-10 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through March 2014

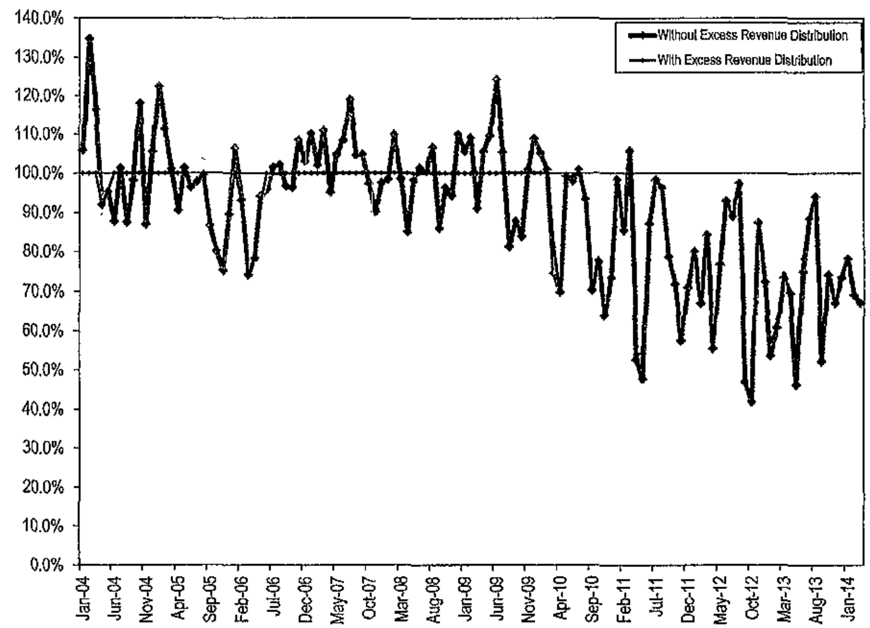


Table 13-14 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves.

Table 13-14 PJM reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	74.5%

*2013/2014 Through 31-Mar-14

FTR Uplift Charge

At the end of the planning period, an uplift charge is applied to FTR holders. This charge is to cover the net of the monthly deficiencies in the target allocations calculated for individual participants. An individual participant's uplift charge is a pro-rata charge, to cover this deficiency, based on their net target allocation with respect to the total net target allocation of all participants with net positive target allocations for the planning period. Participants pay an uplift charge that is a ratio of their share of net positive target allocations to the total net positive target allocations.

The uplift charge is only applied to, and calculated from, members with a net positive target allocation at the end of the planning period. Members with a net negative target allocation have their year-end target allocation set to zero for all uplift calculations. Since participants in the FTR market with net positive target allocations are paying the uplift charge to fully fund FTRs, their payout ratio cannot be 100 percent. The end of planning period payout ratio is calculated as the participant's target allocations minus the uplift charge applied to them divided by their target allocations. The calculations of uplift are structured so that, at the end of the planning period, every participant in the FTR market with a positive net target allocation receives payments based on the same payout ratio. At the end of the planning period and the end of a given month no payout ratio is actually applied to a participant's target allocations. The payout ratio is simply used as a reporting mechanism to demonstrate the amount of revenue available to pay target allocations and represent the percentage of target allocations a participant with a net positive portfolio has been paid for the planning period. However, this same calculation is not accurate when calculating a single month's payout ratio as currently reported, where the calculation of available revenue is not the same.

The total planning period target allocation deficiency is the sum of the monthly deficiencies throughout the planning period. The monthly deficiency is the difference in the net target allocation of all participants and the total revenue collected for that month. The total revenue paid to FTR holders is based on the hourly congestion revenue collected, which includes hourly M2M, wheel payments and unallocated congestion credits.

Table 13-15 provides a demonstration of how the FTR uplift charge is calculated. In this example it is important to note that the sum of the net positive target allocations is $32 and the total monthly deficiency is $10. The uplift charge is structured so that those with higher target allocations pay more of the deficit, which ultimately impacts their net payout. Also, in this example, and in the PJM settlement process, the monthly payout ratio varies for all participants, but the uplift charge is structured so that once the uplift charge is applied the end of planning period payout ratio is the same for all participants.

For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every participant experiences the same payout ratio. This means that some participants subsidize others and receive less payout from their FTRs after the uplift is applied, while others receive a subsidy and get a higher payout after the uplift is applied. In this example, participants 1 and 5 are paid less after the uplift charge is applied, while participants 3 and 4 are paid more.

Table 13-15 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	80.0%	68.8%
2	($4.00)	$0.00	$0.00	$0.00	($4.00)	100.0%	100.0%
3	$15.00	$10.00	$5.00	$4.69	$10.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00		

Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown above in Table 13-16 reflect the PJM reported payout ratios for each month of the planning period. These reported payout ratios equal congestion revenue divided by the sum of the net positive and net negative target allocations for each hour of the month. This does not correctly measure the payout ratio actually received by positive target allocation FTR holders in the month, but provides an estimate of the ratio based on the approach to end of planning period calculations, including cross subsidies.

The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in a month. In fact, the actual monthly payout ratio includes the net negative target allocations as a source of funding for FTRs with net positive target allocations in an hour. Revenue from FTRs with net negative target allocations in an hour is included with congestion revenue when funding FTRs with net positive target allocations.[13] Also included in this revenue is any M2M charge or credit for the month and any excess ARR revenues for the month. The revenue and net target allocations are then summed over the month to calculate the monthly payout ratio. There is no payout ratio applied on a monthly basis, each participant receives a different share of the available revenue based on availability, it is simply used as a reporting mechanism. At the end of a given month, a participant's FTR payments are a proportion of the congestion credits collected, based on the participant's share of the total monthly target allocation. The payout ratio is only used and calculated at the end of the planning period after uplift is applied to each participant. The actual monthly payout ratio received by FTR holders equals congestion revenue plus the net negative target allocations divided by the net positive target allocations for each hour. The actual payout ratio received by the holders of positive target allocation FTRs, reported on a monthly basis, is greater than reported by PJM.

Table 13-16 shows the PJM reported and actual monthly payout ratio for the 2013 to 2014 planning period. In September 2013, the PJM reported payout ratio is 3.4 percentage points below the actual payout ratio. On a month to month basis, the payout ratio currently reported by PJM does not take into account all sources of revenue available to pay FTR holders. On a monthly basis, this provides a slightly overstated level of underfunding.

Table 13-16 PJM Reported and Actual Monthly Payout Ratios: Planning period 2013 to 2014

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jun-13	78.3%	79.5%
Jul-13	88.8%	89.3%
Aug-13	94.1%	94.7%
Sep-13	57.5%	61.0%
Oct-13	74.1%	76.2%
Nov-13	66.9%	69.1%
Dec-13	73.3%	74.9%
Jan-14	78.1%	78.9%
Feb-14	69.0%	70.7%
Mar-14	66.8%	68.1%

Netting Target Allocations within Portfolios

Currently, FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the

13 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), p. 50.

payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

In fact, if done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current system all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Elimination of portfolio netting should also be applied to the end of planning period FTR uplift calculation. With this approach, negative target allocations would not offset positive target allocations at the end of the planning period when allocating uplift. The FTR uplift charge would be based on participants' share of the total positive target allocations paid for the planning period.

Table 13-17 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net target allocation is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly. In this example, the actual monthly payout ratio is 41.7 percent. If portfolio netting were eliminated, the actual monthly payout ratio would rise to 61.1 percent.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 13-17 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive Target Allocation	Negative Target Allocation	Percent Negative Target Allocation	Net Target Allocation	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	-	$115.00	$45.00	$45.00	-

Table 13-18 shows the total value for the 2012 to 2013 and first month of the 2013 to 2014 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

Table 13-18 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2012 to 2013 and 2013 to 2014

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jun-13	$86,723,727.03	$(4,836,911.56)	$164,066,219.78	$(82,101,062.58)	$64,060,468	78.3%	79.5%
Jul-13	$134,302,956.68	$(6,017,377.54)	$255,724,127.63	$(127,113,707.50)	$113,548,567	88.8%	89.3%
Aug-13	$51,545,379.54	$(5,741,002.80)	$104,601,365.20	$(58,796,985.08)	$43,059,687	94.1%	94.7%
Sep-13	$126,168,821.60	$(10,172,695.44)	$279,972,757.24	$(163,977,565.08)	$66,719,631	57.5%	61.0%
Oct-13	$69,748,033.78	$(5,779,197.47)	$158,354,016.98	$(94,365,761.07)	$47,353,545	74.1%	76.2%
Nov-13	$71,460,440.95	$(4,566,565.99)	$156,649,135.09	$(89,755,252.94)	$44,748,426	66.9%	69.1%
Dec-13	$123,125,597.85	$(7,182,126.66)	$256,139,288.91	$(140,195,811.62)	$84,974,997	73.3%	74.9%
Jan-14	$1,081,718,330.35	$(37,626,710.84)	$2,042,537,213.94	$(998,445,595.02)	$815,789,461	78.1%	78.9%
Feb-14	$257,630,277.49	$(14,286,012.96)	$581,660,982.15	$(338,316,718.46)	$167,731,282	69.0%	70.7%
Mar-14	$381,568,929.52	$(14,281,322.99)	$823,861,545.62	$(456,573,939.94)	$245,465,062	66.8%	68.1%
2012/2013 Total	$992,878,751.52	$(86,061,137.29)	$1,897,830,879.73	$(990,471,800.64)	$614,014,377	67.7%	84.5%
2013/2014 Total	$2,383,992,494.79	$(110,489,924.25)	$4,823,566,652.55	$(2,549,642,399.30)	$1,693,451,127	74.5%	88.0%

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.7 percent and the payout ratio for the first ten months of the 2013 to 2014 planning period would have been 88.0 percent instead of 74.5 percent.

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. This increased payout ratio would apply only to negative target allocations associated with counter flow FTRs.

Table 13-19 provides an example of how the counter flow adjustment method would impact a two FTR system. In this example there is $15 of total congestion revenue available, corresponding to a reported payout ratio of 75 percent and a monthly actual payout ratio of 87.5 percent. In the example, the profit before and after underfunding can be seen in addition to the profit after underfunding with the counter flow adjustment made. As illustrated, a counter flow FTR's profit does not change when underfunding is applied, whereas a prevailing flow FTR's profit decreases. Applying the counter flow adjustment distributes the underfunding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-19 Example implementation of counter flow adjustment method

	Prevailing A-B 10MW	Counter C-D 10MW
Auction Cost	$50.00	($30.00)
Target Allocation	$40.00	($20.00)
Payout	$30.00	($20.00)
Profit without underfunding	($10.00)	$10.00
Profit after underfunding	($20.00)	$10.00
Payout for Positive TA	$35.00	($20.00)
Profit for Positive TA	($15.00)	$10.00
Payout after CF Adjustment	$36.67	($21.67)
Profit after CF Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

Table 13-20 shows the monthly positive, negative and total target allocations.[14] Table 13-20 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $159.6 million (27.5 percent of underfunding) in revenue available to fund positive target allocations for the first ten months of the 2013 to 2014 planning period.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the first ten months of the 2013 to 2014 planning period from the reported 74.5 percent to 91.3 percent.

14 Reported payout ratio may differ between Table 13-29 and Table 13-31 due to rounding differences when netting target allocations and considering each FTR individually.

Table 13-20 Counter flow FTR payout ratio adjustment impacts

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jun-13	$164,066,220	($82,101,063)	$81,965,157	$64,060,468	78.2%	$146,161,531	91.9%	$150,770,760
Jul-13	$255,724,128	($127,113,708)	$128,610,420	$113,548,567	88.3%	$240,662,275	95.6%	$244,362,737
Aug-13	$104,601,365	($58,796,985)	$45,804,380	$43,059,687	94.0%	$101,856,672	98.1%	$102,592,928
Sep-13	$279,972,757	($163,977,565)	$115,995,192	$66,719,631	57.5%	$230,697,196	87.3%	$244,550,556
Oct-13	$158,354,017	($94,365,761)	$63,988,256	$47,353,545	74.0%	$141,719,306	92.5%	$146,446,632
Nov-13	$156,649,135	($89,755,253)	$66,893,882	$44,748,426	66.9%	$134,503,679	89.9%	$140,751,323
Dec-13	$256,139,289	($140,195,812)	$115,943,477	$84,974,997	73.3%	$225,170,809	91.3%	$233,817,126
Jan-14	$2,042,537,214	($998,445,595)	$1,044,091,619	$815,789,461	78.1%	$1,814,235,056	91.8%	$1,874,258,807
Feb-14	$581,660,982	($338,316,718)	$243,344,264	$167,731,282	68.9%	$506,048,000	90.9%	$528,451,343
Mar-14	$823,861,546	($456,573,940)	$367,287,606	$245,465,062	66.8%	$702,039,002	89.4%	$736,678,623
Total 2012/2013	$1,897,830,880	($990,471,801)	$907,359,079	$614,537,096	67.7%	$1,605,008,896	88.6%	$1,681,443,058
Total 2013/2014	$4,823,566,653	($2,549,642,399)	$2,273,924,253	$1,693,451,127	74.5%	$4,243,093,526	91.3%	$4,402,680,835

* Reported payout ratios may vary due to rounding differences when netting

Figure 13-12 shows the relationship among balancing congestion, M2M payments and day-ahead congestion. In none of the months was the Day Ahead congestion sufficient to *fully pay target allocations. This* demonstrates an over selling of FTRs *from sources including Stage 1A over* allocation and an imperfect FTR or Day Ahead model.

Figure 13-11 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through March 2014.

Figure 13-11 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through March 2014

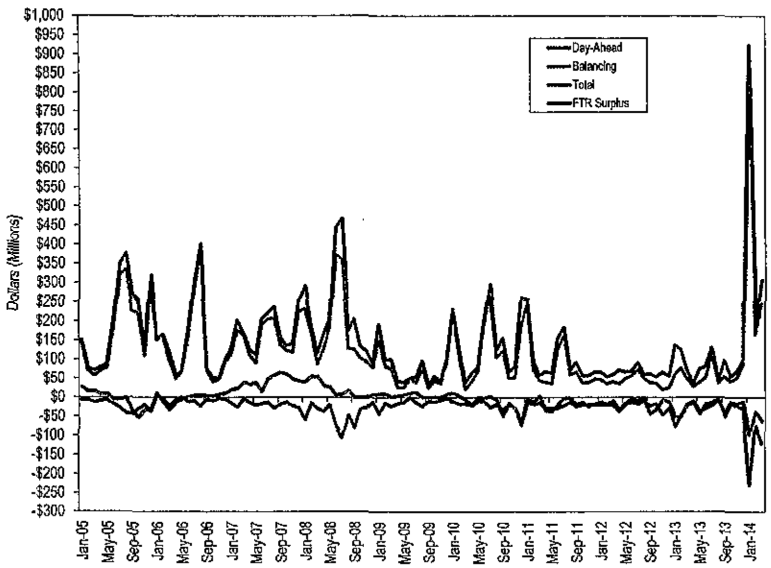
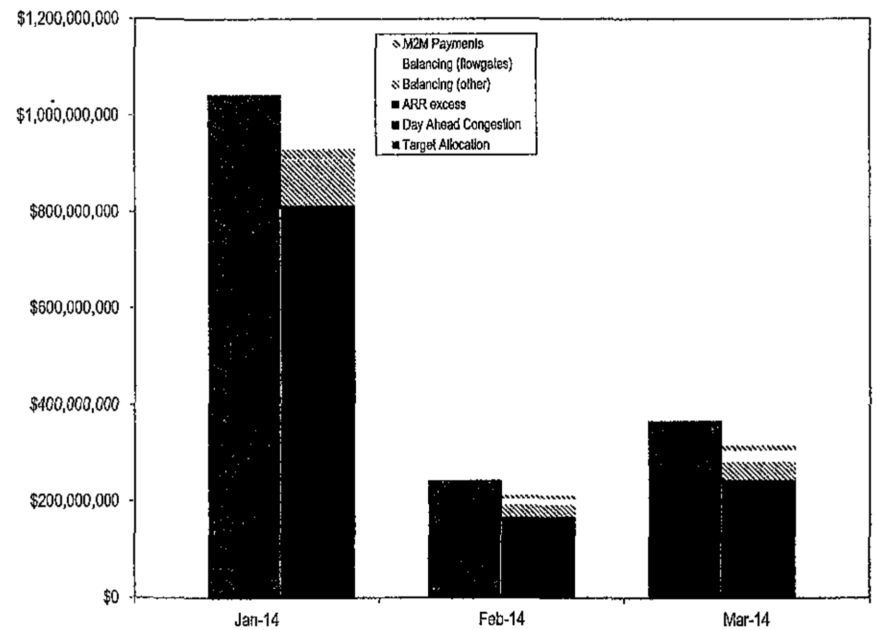


Figure 13-12 FTR target allocation compared to sources of positive and negative congestion revenue



Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[15] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.

ARRs are available only as obligations (not options) and only as the 24-hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[16] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2013 to 2014 planning period, all eligible market participants were allocated ARRs.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. The top ten binding transmission constraints for the 2013 to 2014 planning period are shown in Table 13-21.

15 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

16 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[17] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis. Long Term ARR holders can self schedule their Long Term ARRs as FTRs for any planning period during the 10 planning period timeline.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

- Stage 1A. In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[18]
- Stage 1B. ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.
- Stage 2. Stage 2 of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[19] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing will be introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[20]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[21] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not

17 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

18 See PJM. "Manual 6: Financial Transmission Rights" Revision 15 (October 10, 2013), p. 22.

19 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 21.

20 *See* "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx> The introduction of residual zone pricing, while approved by PJM members, depends on a FERC order.

21 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 55-56.

simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 13-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[22]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating only of ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs.

Table 13-21 shows the top 10 principal binding transmission constraints that limited the 2013 to 2014 Annual ARR Allocation. For the 2013 to 2014 ARR Stage 1A allocation, PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[23]

Table 13-21 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2013 to 2014

Constraint	Type	Control Zone
Cordova - Nelson	Flowgate	MISO
Silver Lake - Cherry Valley	Line	ComEd
Electric Junction - Nelson	Line	ComEd
Oak Grove - Galesburg	Flowgate	MISO
Waukegan-Zion	Line	ComEd
Zion - Lakeview	Line	ComEd
Lakeview	Transformer	MISO
Zion	Transformer	ComEd
Braidwood - East Frankfort	Line	ComEd
Greystone - West Wharton	Line	JCPL

22 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

23 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[24] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 53,988 MW of ARRs associated with approximately $309,200 of revenue that were reassigned for the first ten months of the 2013 to 2014 planning period.

Table 13-22 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2012 and March 2014.

24 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 28.

Table 13-22 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2012, through March 31, 2014

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2012/2013 (12 months)	2013/2014 (10 months)*	2012/2013 (12 months)	2013/2014 (10 months)*
AECO	581	848	$3.0	$3.3
AEP	4,656	7,758	$58.9	$23.4
AP	3,518	2,094	$84.3	$42.6
ATSI	5,314	5,086	$8.3	$7.2
BGE	3,203	3,527	$37.3	$40.4
ComEd	11,824	7,182	$170.9	$73.7
DAY	589	972	$0.9	$1.8
DEOK	2,979	6,715	$1.6	$8.3
DLCO	2,708	4,612	$19.1	$10.3
DPL	1,989	1,893	$11.5	$17.1
Dominion	0	5	$0.0	$0.1
EKPC	NA	0	NA	$0.0
JCPL	1,373	1,358	$5.6	$5.2
Met-Ed	1,107	890	$8.6	$6.5
PECO	3,416	2,162	$22.8	$16.4
PENELEC	920	1,018	$8.3	$9.5
PPL	3,198	2,916	$20.7	$11.7
PSEG	2,313	2,223	$16.6	$22.3
Pepco	3,073	2,516	$21.4	$9.4
RECO	67	215	$0.0	$0.1
Total	52,825	53,988	$499.8	$309.2

* Through 31-Mar-2014

Residual ARRs

Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs are available if additional transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any residual ARRs are available as ARRs in the annual ARR allocation. Stage 1 ARR holders have a priority right to ARRs. Residual ARRs are a separate product from incremental ARRs.

Effective August 1, 2012, as ordered by the FERC in Docket No. EL12-50-000, in addition to new transmission, residual ARRs are now available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. These residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation.

Table 13-23 shows the residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 13-23 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-14	2,809.3	1,760.3	62.7%	$273,006
Feb-14	2,076.9	1,564.0	75.3%	$480,688
Mar-14	11,733.8	1,203.1	10.3%	$1,030,177
Total	16,620.0	4,527.4	27.2%	$1,783,870

Market Performance

Volume

Table 13-24 shows the volume of ARR allocations for each round of the 2012 to 2013 and 2013 to 2014 planning periods.

Table 13-24 Annual ARR Allocation volume: planning periods 2012 to 2013 and 2013 to 2014

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2012/2013	1A	0	16,069	67,302	67,300	100.0%	2	0.0%
	1B	1	11,487	30,013	18,432	61.4%	11,581	38.6%
	2	2	4,887	22,597	2,701	12.0%	19,896	88.0%
		3	3,682	22,496	3,334	14.8%	19,162	85.2%
		4	3,023	22,362	6,219	27.8%	16,143	72.2%
		Total	11,592	67,455	12,254	18.2%	55,201	81.8%
	Total		39,148	164,770	97,986	59.5%	66,784	40.5%
2013/2014	1A	0	18,022	67,861	67,861	100.0%	0	0.0%
	1B	1	14,227	32,679	15,782	48.3%	16,897	51.7%
	2	2	5,476	22,096	3,519	15.9%	18,577	84.1%
		3	4,128	22,480	3,200	14.2%	19,280	85.8%
		4	3,335	22,348	2,612	11.7%	19,736	88.3%
		Total	12,939	66,924	9,331	13.9%	57,593	86.1%
	Total		45,188	167,464	92,974	55.5%	74,490	44.5%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine transmission upgrades so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year of this test PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be included in the PJM RTEP process.

For the 2012 to 2013 planning period, Stage 1A of the Annual ARR Allocation was infeasible. According to Section 7.4.2 (i) of the PJM OATT the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and that these increased limits must then be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability.

The consequence of this increased capability in the models which does not reflect actual capability is an over allocation of both ARRs and FTRs for the entire planning period. In the case of ARRs this over allocation will lower the ARR funding level by selling more capability on the same transmission network. In the case of FTRs the over allocation will exacerbate the underfunding problem by selling more FTRs than are physically feasible with no increase in congestion collected.

Table 13-25 lists the constraints for which ARR requests were found to be infeasible for the 2012 to 2013 ARR Stage 1A Allocation and the MW increase in modeled facility ratings required to make them feasible. In addition, the reason for infeasibility is provided, whether it is an increase in network load, or due to transmission outages in the simultaneous feasibility test.

Table 13-25 Constraints with capacity increases due to Stage 1A infeasibility for the 2013 to 2014 ARR Allocation

Constraint	Contingency	Type	Zone	MW Increase	Reason
Silver Lake - Cherry Valley	Nelson - Electric Junction	Line	ComEd	251	Load
Cordova - Nelson	Nelson	Flowgate	MISO	215	Load
Electric Junction - Nelson	Nelson - Electric Junction	Line	ComEd	202	Load
Oak Grove - Galesburg	Nelson - Electric Junction	Flowgate	MISO	151	Load
Silver Lake - Cherry Valley	BASE	Line	ComEd	139	Load
Waukegan - Zion	BASE	Line	ComEd	129	Load
Zion	Cherry Valley - Silver Lake	Transformer	ComEd	121	Load
Zion - Lakeview	Cherry Valley - Silver Lake	Line	ComEd	121	Load
Lakeview	Cherry Valley - Silver Lake	Transformer	MISO	121	Load
Electric Junction - Nelson	BASE	Line	ComEd	113	Load
Waukegan - Zion	Cherry Valley - Silver Lake	Line	ComEd	106	Load
Roseland - Whippany	Roseland - Readington	Line	PSEG	103	Outages
Roseland - Whippany	BASE	Line	PSEG	93	Outages
Kenney - Mount Olive	New Church - Piney Grove	Line	DPL	70	Outages
Prairie State - W. Mt. Vernon	St Francis - Lutesville	Flowgate	MISO	60	Load
Kenney - Stockton	New Church - Piney Grove	Line	DPL	59	Outages
Mount Olive - Piney	New Church - Piney Grove	Line	DPL	54	Outages
Belvidere - Woodstock	Cherry Valley - Silver Lake	Line	ComEd	51	Load
Belvidere - Chrysler Corp.	Cherry Valley - Silver Lake	Line	ComEd	51	Load
Dixon - Stillman Valley	Nelson - Electric Junction	Line	ComEd	45	Load
Pleasant Valley - Belvidere 2	Cherry Valley - Silver Lake	Line	ComEd	41	Load
McGirr Road - Steward	Nelson - Electric Junction	Line	ComEd	37	Load
Athenia - Saddlebrook	BASE	Line	PSEG	24	Outages
Mazon - Mazon	Kickapoo Creek - Lasalle	Line	ComEd	16	Load
Pleasant Valley - Belvidere 1	Cherry Valley - Silver Lake	Line	ComEd	13	Load

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs.

The adequacy of ARRs as an offset to total congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs offset market participants' actual, total congestion into their zone. Customers that self schedule ARRs as FTRs provide the same offset to congestion as all other FTRs.

ARR holders received a projected $566.7 million in credits from the FTR auctions during the first ten months of the 2013 to 2014 planning period. During the first ten months of the 2013 to 2014 planning period, ARR holders received $505.5 million in ARR credits.

Table 13-26 lists projected ARR target allocations from the Annual ARR Allocation, and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period and the first ten months of the 2013 to 2014 planning periods.

Table 13-26 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

	2012/2013	2013/2014
Total FTR auction net revenue	$626.7	$566.7
Annual FTR Auction net revenue	$602.9	$558.4
Monthly Balance of Planning Period FTR Auction net revenue*	$23.9	$8.3
ARR target allocations	$570.5	$505.5
ARR credits	$570.5	$505.5
Surplus auction revenue	$56.2	$61.1
ARR payout ratio	100%	100%
FTR payout ratio*	67.8%	75.1%

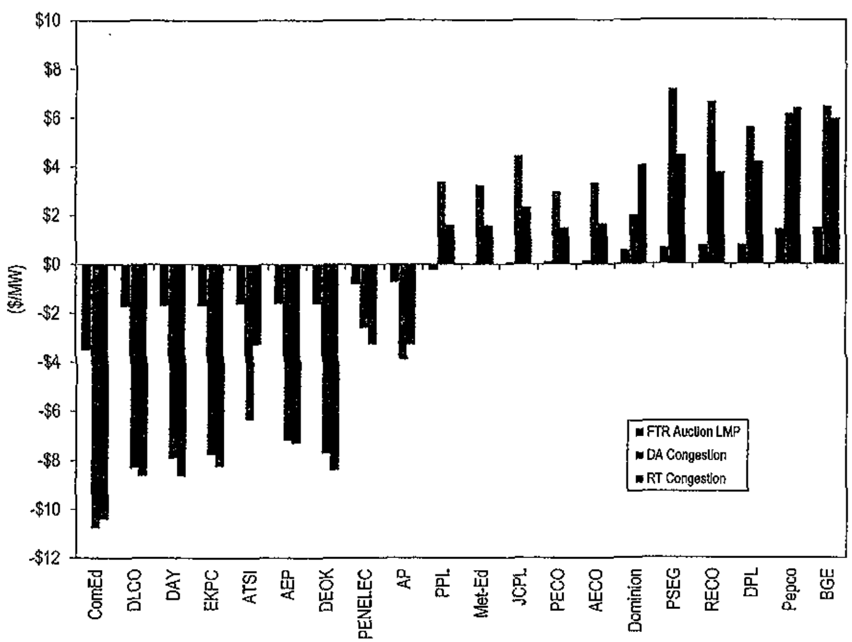
* Shows twelve months for 2012/2013 and ten months for 2013/2014.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 13-13 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the first ten months of the 2013 to 2014 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 13-13 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: 2013 to 2014 planning period through March 31, 2014



Effectiveness of ARRs as an Offset to Congestion

One measure of the effectiveness of ARRs as an offset to congestion is a comparison of the revenue received by the holders of ARRs and the congestion paid by the holders of ARRs in both the Day-Ahead Energy Market and the Balancing Energy Market. The revenue which serves as an offset for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments from the Day-Ahead Energy Market and the Balancing Energy Market. During the first ten months of the 2013 to 2014 planning period, the total revenues received by the holders of all ARRs and FTRs offset 100 percent of the total congestion costs within PJM.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the Balancing Energy Market is presented by control zone in Table 13-27. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[25] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the ARR credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self-scheduled FTR MW) and the cleared price for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and may be less than the target allocation. The FTR payout ratio was 74.5 percent of the target allocation for the first ten months of the 2013 to 2014 planning period. The target allocation is not a guarantee of payment nor does it reflect congestion incurred on a particular FTR path. The target allocation is used to set a cap on path specific FTR payouts.

25 For Table 13-42 through Table 13-44, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first ten months of the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

The Congestion column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the Balancing Energy Market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Table 13-27 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through March 31, 2014[26]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$4.1	$0.0	$4.1	$14.3	($10.3)	28.4%
AEP	$32.4	$138.1	$170.5	($16.4)	$234.1	>100%
APS	$41.6	$56.3	$97.9	($19.2)	$136.4	>100%
ATSI	$5.8	$0.2	$6.0	($8.2)	$14.3	>100%
BGE	$29.3	$2.8	$32.1	$28.7	$4.3	>100%
ComEd	$74.6	$0.0	$74.6	$21.1	$53.5	>100%
DAY	$4.0	$0.0	$4.0	($6.1)	$10.2	>100%
DEOK	$3.7	$1.6	$5.3	($12.7)	$18.6	>100%
DLCO	$1.9	($0.2)	$1.6	($4.3)	$5.8	>100%
Dominion	$7.7	$165.0	$172.6	$14.3	$214.8	>100%
DPL	$17.2	$3.5	$20.7	$36.7	($14.9)	56.3%
EKPC	$0.6	$0.3	$0.9	($6.1)	$7.1	>100%
External	$2.2	$1.2	$3.4	$10.3	($6.5)	33.3%
JCPL	$6.7	$0.1	$6.7	$32.6	($25.8)	20.7%
Met-Ed	$6.8	$0.3	$7.1	$14.4	($7.2)	49.3%
PECO	$22.3	$0.3	$22.5	($15.6)	$38.2	>100%
PENELEC	$12.1	($1.3)	$10.8	$11.0	($0.6)	98.4%
Pepco	$16.4	$8.4	$24.8	$46.5	($18.8)	53.4%
PPL	$10.8	$0.6	$11.4	$59.6	($48.0)	19.1%
PSEG	$37.2	$8.2	$45.4	$12.8	$35.5	>100%
RECO	$0.1	$0.0	$0.1	$2.0	($1.9)	5.0%
Total	$337.5	$394.3	$731.9	$215.6	$651.3	>100%

26 The "External" zone was labeled as "PJM" in previous State of the Market Reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM interfaces.

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-28 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the Balancing Energy Market for the first ten months of the 2013 to 2014 planning period. This compares the total offset provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the cleared price of the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions, and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 74.5 percent of the target allocation for the first ten months of the 2013 to 2014 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR offset is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the Balancing Energy Market in each control zone.[27] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

27 The total zonal congestion numbers were calculated as of April 15, 2014 and may change as a result of continued PJM billing updates.

Table 13-28 ARR and FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through March 31, 2014

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$4.1	$11.5	$5.6	$10.0	$28.7	($18.7)	34.8%
AEP	$83.5	$255.0	$102.0	$236.4	$400.6	($164.2)	59.0%
APS	$65.9	$102.5	$34.9	$133.5	$193.1	($59.6)	69.1%
ATSI	$5.9	$80.7	$2.0	$84.5	($41.6)	$126.2	>100%
BGE	$30.5	$79.7	$34.9	$75.4	$116.2	($40.9)	64.8%
ComEd	$84.2	$93.8	$54.0	$124.0	$296.3	($172.4)	41.8%
DAY	$4.0	$11.2	$4.0	$11.2	($1.3)	$12.6	>100%
DEOK	$4.4	$12.5	$4.4	$12.5	($26.3)	$38.8	>100%
DLCO	$2.1	($6.8)	$0.5	($5.2)	($11.5)	$6.3	0.0%
Dominion	$94.9	$284.7	$134.4	$245.2	$179.0	$66.2	>100%
DPL	$19.4	$61.5	$16.2	$64.7	$99.6	($34.9)	64.9%
EKPC	$2.1	$3.3	$3.0	$2.4	($12.7)	$15.1	>100%
External	$2.8	$17.1	$1.3	$18.6	$81.2	($62.5)	23.0%
JCPL	$6.7	$80.5	$5.9	$81.3	$99.3	($18.0)	81.9%
MetEd	$6.9	$32.2	$5.8	$33.3	($12.1)	$45.3	>100%
PECO	$22.4	$20.0	$18.3	$24.1	($48.9)	$73.0	>100%
PENELEC	$11.9	$93.9	$41.5	$64.3	$111.8	($47.6)	57.5%
Pepco	$19.7	$175.2	$76.8	$118.1	$131.8	($13.7)	89.6%
PPL	$10.9	$39.8	($1.5)	$52.2	($8.1)	$60.3	>100%
PSEG	$38.7	$239.1	$53.9	$223.9	$66.5	$157.4	>100%
RECO	$0.1	($0.9)	($1.3)	$0.5	$12.1	($11.7)	3.9%
Total	$520.9	$1,688.6	$596.8	$1,612.8	$1,653.7	($40.9)	97.5%

Table 13-29 shows the total offset due to ARRs and FTRs for the entire 2012 to 2013 and the first ten months of the 2013 to 2014 planning periods. ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 97.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Table 13-29 ARR and FTR congestion hedging (in millions): Planning periods 2012 to 2013 and 2013 to 2014[28]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2012/2013	$577.2	$610.3	$654.1	$533.4	$575.9	($42.5)	92.6%
2013/2014*	$520.9	$1,688.6	$596.8	$1,612.8	$1,653.7	($40.9)	97.5%

* Shows ten months ended March 31, 2014

28 The FTR credits do not include after-the-fact adjustments. For the 2013 to 2014 planning period, the ARR credits were the total credits allocated to all ARR of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the planning period and the portion of Annual FTR Auction revenue distributed to the entire planning period.