Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market for dispatch based on incremental offer curves and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.[2]

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by 178.7 percent or $472.6 million in the first three months of 2014 compared to the first three months of 2013, from $264.5 million to $737.1 million. This change was the result of an increase of $507.1 million in balancing operating reserve charges, an increase of $28.2 million in day-ahead operating reserve charges and an increase of $0.1 million in synchronous condensing charges. These increases were partially offset by a decrease of $48.1 million in reactive services charges and a decrease of $14.7 million in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.229 per MWh. The balancing operating reserve reliability rates averaged $1.890, $0.041 and $0.026 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $3.509, $1.013 and $0.323 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $2.918 per MWh and the canceled resources rate averaged $0.0002 per MWh.
- **Reactive Services Rates.** The PENELEC, DPL and ATSI control zones had the three highest reactive local voltage support rates: $0.277, $0.272 and $0.185 per MWh. The reactive transfer interface support rate averaged $0.001 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 62.8 percent of all day-ahead generator credits and 59.8 percent of all balancing generator credits. Combustion turbines and diesels received 61.5 percent of the lost opportunity cost credits. Coal units received 73.9 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 42.8 percent of all credits. The top 10 organizations received 83.6 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4889, balancing operating reserves HHI was 2919, lost opportunity cost HHI was 3647 and reactive services HHI was 7395.
- **Economic and Noneconomic Generation.** In the first three months of 2014, 90.4 percent of the day-ahead generation eligible for operating reserve credits was economic and 74.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability:** In the first three months of 2014, 4.0 percent of the total day-ahead generation was scheduled as must run by PJM, of which 21.0 percent received energy uplift payments.

Geography of Charges and Credits

- In the first three months of 2014, 91.3 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generators, 1.9 percent by transactions at hubs and aggregates and 6.8 percent by transactions at interfaces.

1 Loss is defined as gross energy and ancillary services market revenues less than total energy offer, which are startup, no load and incremental offers.

2 Other types of energy uplift charges are make whole payments to emergency demand response resources and emergency transaction purchases. These categories are not covered in this section. See Section 6, "Demand Response" and Section 9 "Interchange Transactions" for an explanation on these payments.

Energy Uplift Issues

- **Lost Opportunity Cost Credits:** In the first three months of 2014, lost opportunity cost credits increased by $77.7 million compared to the first three months of 2013. In the first three months of 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 58.2 percent of all lost opportunity cost credits, 44.8 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 50.9 percent of all day-ahead generation not committed in real time by PJM from those unit types and 60.2 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first three months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $7.5 million.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in the first three months of 2014, the average rate paid by a DEC in the Eastern Region would have been $0.635 per MWh, which is $5.928 per MWh less than the actual average rate paid.

January through March 2014 Energy Uplift Charges Increase

- **Day-ahead Operating Reserve Charges:** The largest impact on day-ahead operating reserves was from units that cleared in the Day-Ahead Energy Market and were economic for less than 50 percent of their scheduled run time. In the first three months of 2014, day-ahead operating reserve credits paid to such units increased by $21.3 million from $3.7 million in the first three months of 2013.
- **Balancing Operating Reserve Charges:** The largest impact on balancing operating reserve charges was credits paid to units committed for conservative operations with offers significantly higher than the LMP, primarily as a result of high natural gas prices. Energy uplift payments to units committed for reliability purposes before the operating day are allocated as balancing operating reserve charges for reliability. Balancing operating reserve charges for reliability increased by $406.2 million in the first three months of 2014 compared to the first three months of 2013.
- **Lost Opportunity Cost:** The second largest impact on balancing operating reserve charges was credits for lost opportunity cost (LOC) to units scheduled in the Day-Ahead Energy Market and not committed in real time or to units reduced in real time. LOC compensation increased by $77.2 million in the first three months of 2014 compared to the first three months of 2013.

Recommendations

- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of

these interfaces. The MMU recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.

- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region.
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output.
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.
- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. The MMU recommends including real-time exports in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load.
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions.

Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start charges.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and that the allocation of these charges reflects the reasons that the costs are incurred to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations has persisted for more than ten years.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[3] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators actions in LMP.[4]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Energy Uplift

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when hourly LMP is less than the offer price including energy, no load and startup costs.

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy

3 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.

4 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

uplift charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:	Charges Category:	Charges Paid By:	
	Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Balancing			
Generation Resources	Balancing Operating Reserve Generator	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
		Balancing Operating Reserve for Deviations	Deviations	
		Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC			
Real-Time Import Transactions	Balancing Operating Reserve Transaction			
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator			
Economic Load Response Resources	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge Reactive Services Local Constraint	Zonal Real-Time Load Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges increased by 178.7 percent in the first three months of 2014 compared to the first three months of 2013, to a total of $737.1 million. Table 4-3 shows total energy uplift charges in the first three months of 2013 and 2014.[5]

Table 4-3 Total energy uplift charges: January through March 2013 and 2014

	Jan - Mar 2013	Jan - Mar 2014	Change	Percentage Change
Total Energy Uplift Charges	$264,450,578	$737,090,222	$472,639,644	178.7%
Energy Uplift as a Percent of Total PJM Billing	3.4%	3.5%	0.1%	2.7%

Total energy uplift charges increased by $472.6 million or 178.7 percent in the first three months of 2014 compared to the first three months of 2013. Table 4-4 compares energy uplift charges by category for the first three months of 2013 and the first three months of 2014. The increase of $472.6 million in the first three months of 2014 is comprised of an increase of $28.2 million in day-ahead operating reserve charges, an increase of $507.1 million in balancing operating reserve charges, a decrease of $48.1 million in reactive services charges, an increase of $0.1 million in synchronous condensing charges and a decrease of $14.7 million in black start services charges. The increase in total energy uplift charges was a result of high demand, high natural gas costs and high LMPs. High natural gas prices and higher energy offers for units scheduled in the Day-Ahead Energy Market and units committed in real time for conservative operations increased the day-ahead and balancing operating reserve charges. Higher energy prices reduced the energy uplift for coal units providing black start and reactive support.

5 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 23, 2014.

Table 4-4 Energy uplift charges by category: January through March 2013 and 2014

Category	Jan - Mar 2013	Jan - Mar 2014	Change	Percentage Change
Day-Ahead Operating Reserves	$22,937,876	$51,159,327	$28,221,451	123.0%
Balancing Operating Reserves	$163,720,826	$670,814,754	$507,093,928	309.7%
Reactive Services	$55,579,356	$7,504,927	($48,074,429)	(86.5%)
Synchronous Condensing	$1,873	$54,736	$52,863	2,821.8%
Black Start Services	$22,210,646	$7,556,479	($14,654,168)	(66.0%)
Total	$264,450,578	$737,090,222	$472,639,644	178.7%

The increase in energy uplift charges increase in the first three months of 2014 occurred entirely in January. Total energy uplift charges increased $477.0 million in January 2014 compared to January 2013, while energy uplift charges decreased by $4.4 million in February and March 2014 compared to February and March 2013. Table 4-5 compares monthly energy uplift charges by category for 2013 and 2014.

Table 4-6 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[6,7] Day-ahead operating reserve charges increased by $28.2 million or 123.0 percent in the first three months of 2014 compared to the first three months of 2013. Day-ahead operating reserve charges (excluding unallocated congestion charges) increased by $33.8 million or 193.8 percent in the first three months of 2014 compared to the first three months of 2013. This increase was primarily the result of higher natural gas prices and higher energy offers. In the first three months of 2014, even though the day-ahead generation from units paid day-ahead operating reserve credits was 17.4 percent lower compared to the first three months of 2013, the difference between the energy revenues paid to these units and their offers in dollars per MWh of scheduled generation increased by 255.6 percent, from $4.48 per MWh to $15.93 per MWh. There were zero unallocated congestion charges in the first three months of 2014 compared to $5.6 million in the first three months of 2013.

Table 4-5 Monthly energy uplift charges: 2013 and 2014

	2013						2014					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$11,122,613	$79,179,040	$23,604,234	$1,873	$8,453,397	$122,361,157	$35,905,254	$555,622,212	$3,779,096	$54,736	$4,037,517	$599,398,816
Feb	$5,126,444	$67,126,247	$17,624,984	$0	$6,988,632	$96,866,306	$9,581,330	$55,786,364	$1,043,326	$0	$883,414	$67,294,434
Mar	$6,688,819	$17,415,540	$14,350,138	$0	$6,768,618	$45,223,115	$5,672,743	$59,406,178	$2,682,504	$0	$2,635,547	$70,396,972
Apr	$5,712,618	$23,429,237	$13,670,581	$0	$9,242,815	$52,055,252						
May	$10,785,679	$22,524,918	$17,214,142	$959	$8,667,665	$59,193,362						
Jun	$9,349,928	$17,885,782	$22,055,239	$0	$7,954,457	$57,245,406						
Jul	$8,309,568	$43,233,634	$19,633,771	$393,413	$5,858,221	$77,428,607						
Aug	$4,159,471	$14,674,041	$27,827,070	$0	$7,584,998	$54,245,580						
Sep	$12,414,799	$30,965,833	$27,534,905	$0	$7,384,554	$78,300,091						
Oct	$2,473,704	$12,767,971	$41,721,299	$0	$6,708,931	$63,671,906						
Nov	$2,799,521	$17,709,921	$42,743,907	$132	$6,685,965	$69,939,447						
Dec	$5,644,916	$36,018,616	$43,464,829	$0	$4,403,308	$89,531,670						
Total (Jan - Mar)	$22,937,876	$163,720,826	$55,579,356	$1,873	$22,210,646	$264,450,578	$51,159,327	$670,814,754	$7,504,927	$54,736	$7,556,479	$737,090,222
Share (Jan - Mar)	8.7%	61.9%	21.0%	0.0%	8.4%	100.0%	6.9%	91.0%	1.0%	0.0%	1.0%	100.0%
Total	$84,588,080	$382,930,781	$311,445,099	$396,377	$86,701,561	$866,061,898	$51,159,327	$670,814,754	$7,504,927	$54,736	$7,556,479	$737,090,222
Share	9.8%	44.2%	36.0%	0.0%	10.0%	100.0%	5.9%	77.5%	0.9%	0.0%	0.9%	85.1%

6 See OATT Attachment K-Appendix § 3.2.3 (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves ten times, totaling $26.9 million.
7 See Section 13, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

Table 4-6 Day-ahead operating reserve charges: January through March 2013 and 2014

Type	Jan - Mar 2013	Jan - Mar 2014	Change	Jan - Mar 2013 Share	Jan - Mar 2014 Share
Day-Ahead Operating Reserve Charges	$17,357,053	$50,992,235	$33,635,182	75.7%	99.7%
Day-Ahead Operating Reserve Charges for Load Response	$0	$167,092	$167,092	0.0%	0.3%
Unallocated Congestion Charges	$5,580,823	$0	($5,580,823)	24.3%	0.0%
Total	$22,937,876	$51,159,327	$28,221,451	100.0%	100.0%

Table 4-7 Balancing operating reserve charges: January through March 2013 and 2014

Type	Jan - Mar 2013	Jan - Mar 2014	Change	Jan - Mar 2013 Share	Jan - Mar 2014 Share
Balancing Operating Reserve Reliability Charges	$18,245,699	$424,398,570	$406,152,870	11.1%	63.3%
Balancing Operating Reserve Deviation Charges	$145,455,932	$245,574,840	$100,118,908	88.8%	36.6%
Balancing Operating Reserve Charges for Load Response	$892	$5,632	$4,740	0.0%	0.0%
Balancing Local Constraint Charges	$18,303	$835,712	$817,410	0.0%	0.1%
Total	$163,720,826	$670,814,754	$507,093,928	100.0%	100.0%

Table 4-8 Balancing operating reserve deviation charges: January through March 2013 and 2014

Charge Attributable To	Jan - Mar 2013	Jan - Mar 2014	Change	Jan - Mar 2013 Share	Jan - Mar 2014 Share
Make Whole Payments to Generators and Imports	$122,088,879	$144,481,821	$22,392,942	83.9%	58.8%
Energy Lost Opportunity Cost	$23,339,277	$101,086,896	$77,747,619	16.0%	41.2%
Canceled Resources	$27,776	$6,122	($21,654)	0.0%	0.0%
Total	$145,455,932	$245,574,840	$100,118,907	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $507.1 million in the first three months of 2014 compared to the first three months of 2013. This increase was primarily the result of higher natural gas prices and higher energy offers combined with significantly higher conservative operations commitment and lost opportunity cost compensation to generators scheduled in the Day-Ahead Energy Market and not committed in real time, and to generators reduced in real time for reliability purposes.

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first three months of 2014, 58.8 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 25.1 percentage points compared to the share in the first three months of 2013.

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $48.1 million in the first three months of 2014 compared to the first three months of 2013. Black start services charges decreased by $14.7 million in the first three months of 2014 compared to the first three months of 2013. Both categories decreased primarily as a result of the fact that higher energy prices made the units more economic than in the first three months of 2013. Reduced FMU adders also decreased the amount of energy uplift paid to units providing reactive support.

Table 4-9 Additional energy uplift charges: January through March 2013 and 2014

Type	Jan - Mar 2013	Jan - Mar 2014	Change	Jan - Mar 2013 Share	Jan - Mar 2014 Share
Reactive Services Charges	$55,579,356	$7,504,927	($48,074,429)	71.4%	49.6%
Synchronous Condensing Charges	$1,873	$54,736	$52,863	0.0%	0.4%
Black Start Services Charges	$22,210,646	$7,556,479	($14,654,168)	28.6%	50.0%
Total	$77,791,876	$15,116,141	($62,675,735)	100.0%	100.0%

Table 4-10 Regional balancing charges allocation: January through March 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$11,415,915	7.0%	$6,088,270	3.7%	$323,720	0.2%	$17,827,906	10.9%
	Real-Time Exports	$239,477	0.1%	$173,099	0.1%	$5,218	0.0%	$417,793	0.3%
	Total	$11,655,392	7.1%	$6,261,369	3.8%	$328,938	0.2%	$18,245,699	11.1%
Deviation Charges	Demand	$31,906,867	19.5%	$56,568,969	34.6%	$463,405	0.3%	$88,939,241	54.3%
	Supply	$8,730,814	5.3%	$15,452,612	9.4%	$118,803	0.1%	$24,302,230	14.8%
	Generator	$13,233,780	8.1%	$18,712,987	11.4%	$267,695	0.2%	$32,214,462	19.7%
	Total	$53,871,461	32.9%	$90,734,568	55.4%	$849,903	0.5%	$145,455,932	88.9%
Total Regional Balancing Charges		$65,526,853	40.0%	$96,995,937	59.3%	$1,178,842	0.7%	$163,701,632	100%

Table 4-11 Regional balancing charges allocation: January through March 2014

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$410,150,934	61.2%	$4,079,907	0.6%	$3,021,644	0.5%	$417,252,485	62.3%
	Real-Time Exports	$6,913,928	1.0%	$145,161	0.0%	$86,996	0.0%	$7,146,085	1.1%
	Total	$417,064,862	62.3%	$4,225,068	0.6%	$3,108,640	0.5%	$424,398,570	63.3%
Deviation Charges	Demand	$119,052,150	17.8%	$10,062,000	1.5%	$3,102,805	0.5%	$132,216,955	19.7%
	Supply	$33,464,455	5.0%	$2,979,292	0.4%	$640,598	0.1%	$37,084,345	5.5%
	Generator	$70,120,080	10.5%	$4,329,128	0.6%	$1,824,332	0.3%	$76,273,540	11.4%
	Total	$222,636,685	33.2%	$17,370,420	2.6%	$5,567,735	0.8%	$245,574,840	36.7%
Total Regional Balancing Charges		$639,701,547	95.5%	$21,595,488	3.2%	$8,676,375	1.3%	$669,973,409	100%

Table 4-10 and Table 4-11 show the amount and percentages of regional balancing charges for the first three months of 2013 and 2014. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by real-time load. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first three months of 2014, regional balancing operating reserve charges increased by $506.3 million compared to the first three months of 2013. Balancing operating reserve reliability charges increased by $406.2 million or 2,226.0 percent and balancing operating reserve deviation charges increased by $100.1 million or 68.8 percent.

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. See Table 4-1 for how these charges are allocated.[8]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2013 and the first three months of 2014. The average rate in the first three months of 2014 was $0.229 per MWh, $0.147 per MWh higher than the average in the first three months of 2013. The highest rate occurred on January 22, when the rate reached $1.689 per MWh, $1.471 per MWh higher than the $0.218 per MWh reached in the first three months of 2013, on March 24. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in the first three months of 2014. The increase in the day-ahead operating reserve rate on January 22 was in large part the result of scheduling peaking resources which were noneconomic or economic for less

8 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO region since these three charges are allocated following the same rules.

than 50 percent of their scheduled run time. On January 22, 116 units received day-ahead operating reserve credits, 86 were economic for 50 percent or less of their scheduled run time. That was the highest number of units scheduled noneconomic in the Day-Ahead Energy Market in the first three months of 2014. Also, on January 22, 60 units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; eight of these units received enough net revenues from day-ahead scheduling reserves to cover their total energy offer (including no load and startup cost), which would have resulted in zero day-ahead operating reserve credits if the net revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[9]

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2013 and 2014

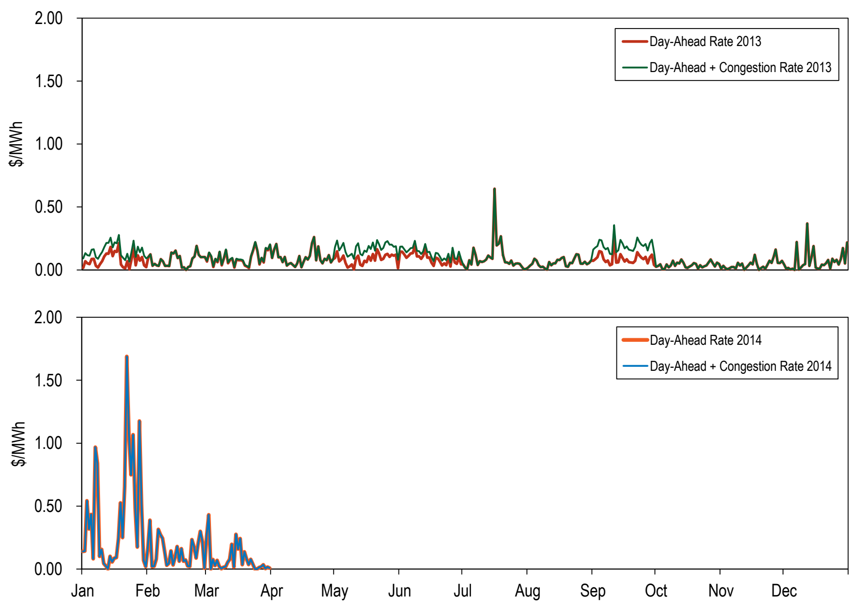


Figure 4-2 shows the RTO and the regional reliability rates for 2013 and the first three months of 2014. The average daily RTO reliability rate was $1.890 per MWh. The highest RTO reliability rate in the first three months of 2014 occurred on January 28, when the rate reached $24.546 per MWh, $23.744 per MWh higher than the $0.802 per MWh rate reached in the first three months of 2013, on January 23. The increases in the RTO reliability rate on January 3, January 8 and between January 21 and 28 were the result of the commitment for conservative operations of natural gas fired generators with high offers.[10]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2013 and 2014

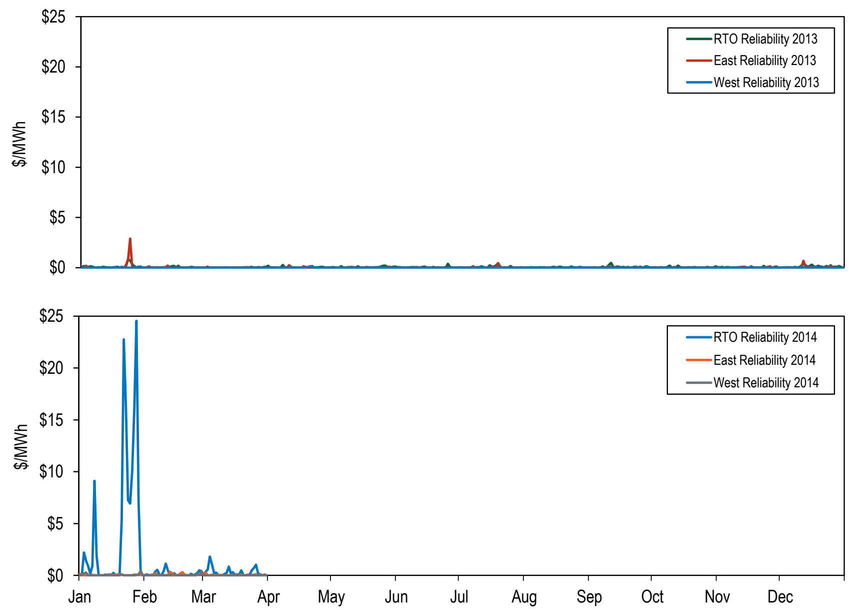


Figure 4-3 shows the RTO and regional deviation rates for 2013 and the first three months of 2014. The average daily RTO deviation rate was $3.509 per MWh. The highest daily rate in the first three months of 2014 occurred on

9 Net revenues from day-ahead scheduling reserves are used as offsets in the balancing operating reserve calculation.

10 See "Energy Uplift and Conservative Operations" in this section for an explanation of the reasons and impact of units committed for conservative operations.

January 25, when the RTO deviation rate reached $20.082 per MWh, $9.910 per MWh higher than the $10.172 per MWh rate reached in the first three months of 2013, on January 23. In the first three months of 2014 the RTO deviation rate increased while the Eastern Region deviation rate decreased, compared to the first three months of 2013. In the first three months of 2013 energy uplift was paid primarily to units committed to provide relief to local transmission constraints in the Eastern Region, while in the first three months of 2014, energy uplift was paid primarily to units committed to meet overall load and provide reserves for peak hours.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2013 and 2014

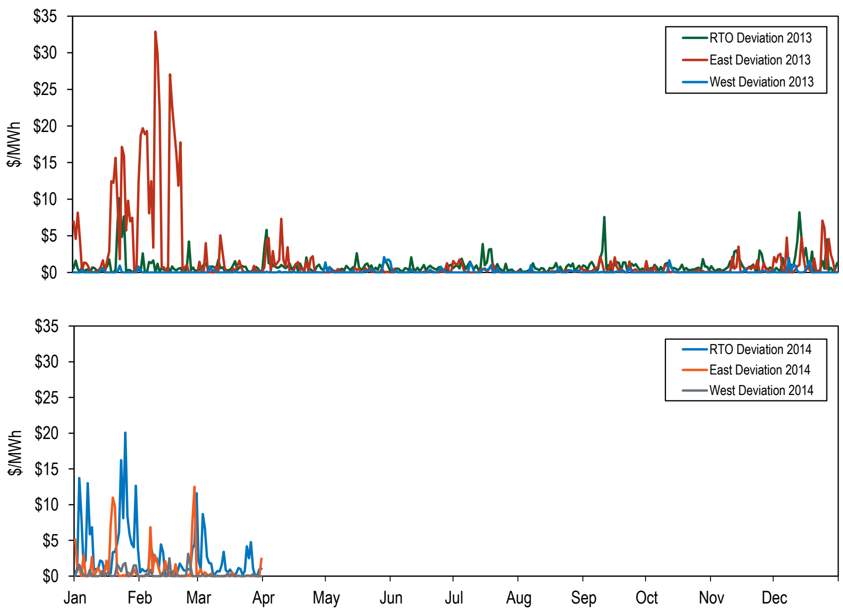


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2013 and the first three months of 2014. The lost opportunity cost rate averaged $2.918 per MWh. The highest lost opportunity cost rate occurred on January 24, when it reached $32.556 per MWh, $27.685 per MWh higher than the $4.871 per MWh rate reached in the first three months of 2013, on January 25. On January 24, 2014, 63.5 percent of the lost opportunity cost rate was due to units reduced in real time for reliability purposes.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2013 and 2014

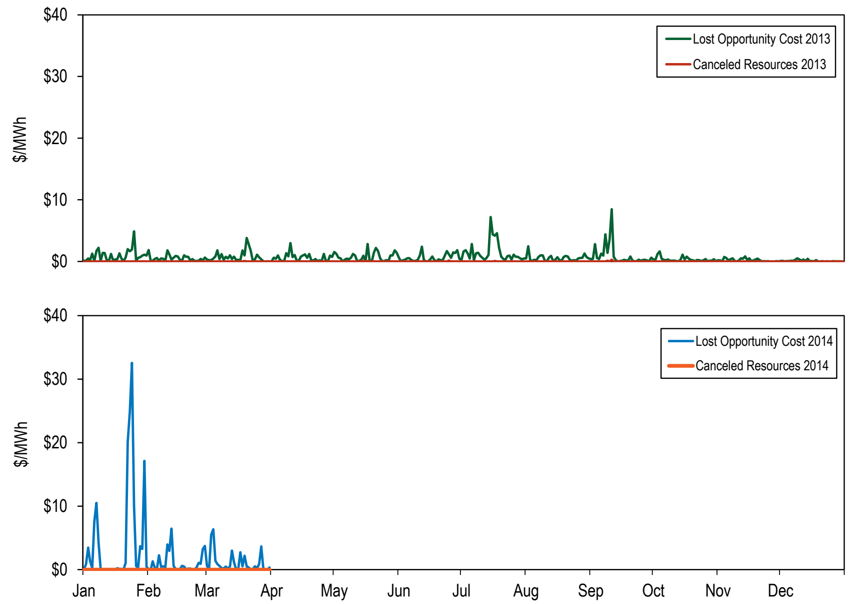


Table 4-12 shows the average rates for each region in each category for the first three months of 2013 and the first three months of 2014.

Table 4-12 Operating reserve rates ($/MWh): January through March 2013 and 2014

Rate	Jan - Mar 2013 ($/MWh)	Jan - Mar 2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.082	0.229	0.147	178.6%
Day-Ahead with Unallocated Congestion	0.109	0.229	0.120	110.8%
RTO Reliability	0.058	1.890	1.832	3,175.7%
East Reliability	0.065	0.041	(0.024)	(36.6%)
West Reliability	0.003	0.026	0.023	745.3%
RTO Deviation	1.026	3.509	2.483	241.9%
East Deviation	6.024	1.013	(5.012)	(83.2%)
West Deviation	0.061	0.323	0.262	430.8%
Lost Opportunity Cost	0.785	2.918	2.133	271.7%
Canceled Resources	0.001	0.000	(0.001)	(81.1%)

Table 4-13 shows the operating reserve cost of a one MW transaction during the first three months of 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $6.563 per MWh with a maximum rate of $42.173 per MWh, a minimum rate of $0.109 per MWh and a standard deviation of $8.585 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): January through March 2014

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	41.100	6.351	0.104	8.387
	DEC	42.173	6.563	0.109	8.585
	DA Load	1.689	0.212	0.000	0.301
	RT Load	24.583	1.697	0.004	4.483
	Deviation	41.100	6.351	0.104	8.387
West	INC	42.260	5.593	0.104	8.459
	DEC	43.008	5.805	0.109	8.659
	DA Load	1.689	0.212	0.000	0.301
	RT Load	24.606	1.682	0.001	4.486
	Deviation	42.260	5.593	0.104	8.459

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer.

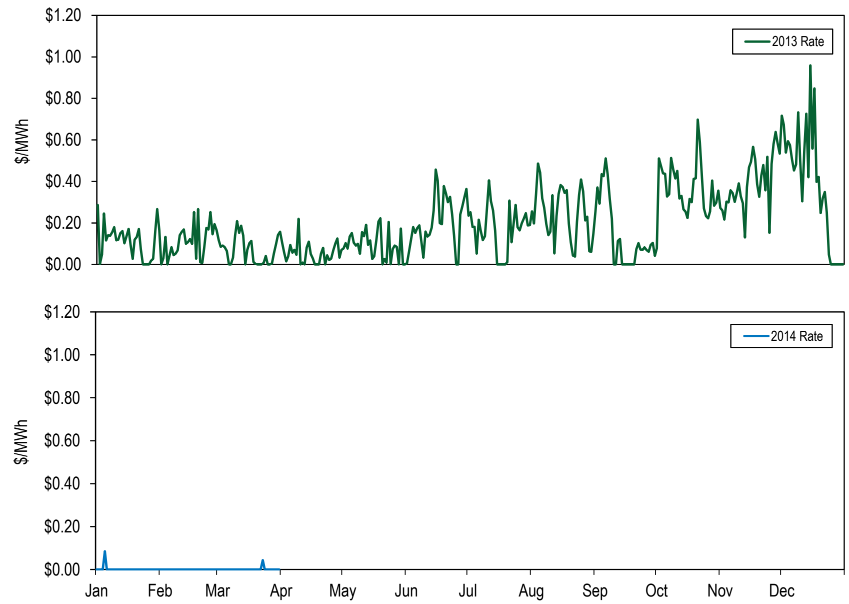
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support for the first three months of 2013 and the first three months of 2014. Table 4-14 shows that in the first three months of 2014 the PENELEC Control Zone had the highest rate. Real-time load in the PENELEC Control Zone paid an average of $0.277 per MWh for reactive services associated with local voltage support, $0.659 or 70.4 percent lower than the average rate paid in the first three months of 2013.

Table 4-14 Local voltage support rates: January through March 2013 and 2014

Control Zone	Jan - Mar 2013 ($/MWh)	Jan - Mar 2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.768	0.030	(0.737)	(96.1%)
AEP	0.000	0.004	0.004	2,396.5%
AP	0.003	0.017	0.014	429.7%
ATSI	1.031	0.185	(0.846)	(82.1%)
BGE	0.018	0.002	(0.016)	(86.6%)
ComEd	0.000	0.000	0.000	0.0%
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.016	0.000	(0.016)	(100.0%)
DPL	1.262	0.272	(0.990)	(78.5%)
EKPC	NA	0.000	NA	NA
JCPL	0.825	0.000	(0.825)	(100.0%)
Met-Ed	0.026	0.002	(0.024)	(91.3%)
PECO	0.000	0.023	0.023	NA
PENELEC	0.936	0.277	(0.659)	(70.4%)
Pepco	0.019	0.002	(0.016)	(87.3%)
PPL	0.000	0.000	0.000	0.0%
PSEG	0.165	0.032	(0.133)	(80.7%)
RECO	0.000	0.000	0.000	0.0%

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2013 and the first three months of 2014. The average rate in the first three months of 2014 was $0.001 per MWh, 98.6 percent lower than the $0.094 per MWh average rate in the first three months of 2013. In the first three months of 2014 energy uplift was paid to units providing support to the reactive transfer interfaces for only two days. The significant decrease in reactive services charges allocated across the RTO was a result of the fact that units that were previously scheduled noneconomic to provide reactive services became economic based on higher energy prices and lower offers from the units providing reactive support due to reduced FMU adders, and therefore cleared the Day-Ahead Energy Market based on economics.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2013 and 2014



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges for the first three months of 2013 and the first three months of 2014. Total real-time load and real-time exports were 18,663,325 MWh or 9.2 percent higher in the first three months of 2014 compared to the first three months of 2013. Total deviations summed across the demand, supply, and generator categories were 4,912,314 MWh or 16.5 percent higher in the first three months of 2014 compared to the first three months of 2013.

Table 4-15 Balancing operating reserve determinants (MWh): January through March 2013 and 2014

		Reliability Charge Determinants			Deviation Charge Determinants			
		Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
Jan - Mar 2013	RTO	197,195,752	4,812,740	202,008,491	17,995,937	4,418,911	7,312,173	29,727,021
	East	93,547,149	3,081,987	96,629,136	9,724,337	2,248,135	3,088,591	15,061,062
	West	103,648,603	1,730,753	105,379,356	7,714,724	2,031,149	4,223,583	13,969,455
Jan - Mar 2014	RTO	212,266,877	8,404,939	220,671,816	19,350,321	5,178,477	10,110,536	34,639,335
	East	99,428,266	3,425,428	102,853,695	9,538,725	3,090,073	4,523,501	17,152,300
	West	112,838,610	4,979,511	117,818,121	9,666,069	1,988,240	5,587,035	17,241,345
Difference	RTO	15,071,125	3,592,200	18,663,325	1,354,384	759,567	2,798,363	4,912,314
	East	5,881,117	343,442	6,224,559	(185,612)	841,939	1,434,911	2,091,237
	West	9,190,008	3,248,758	12,438,766	1,951,345	(42,909)	1,363,453	3,271,889

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In the first three months of 2014, 16.6 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 83.4 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: January through March 2014

Deviation Category	Transaction	Deviation (MWh) RTO	Deviation (MWh) East	Deviation (MWh) West	Share RTO	Share East	Share West
Demand	Bilateral Sales Only	128,306	67,291	61,015	0.4%	0.4%	0.4%
	DECs Only	2,054,820	582,474	1,328,923	5.9%	3.4%	7.7%
	Exports Only	1,426,055	696,293	729,763	4.1%	4.1%	4.2%
	Load Only	13,523,356	7,036,901	6,486,455	39.0%	41.0%	37.6%
	Combination with DECs	1,539,340	881,806	655,430	4.4%	5.1%	3.8%
	Combination without DECs	678,444	273,961	404,483	2.0%	1.6%	2.3%
Supply	Bilateral Purchases Only	159,242	87,982	71,260	0.5%	0.5%	0.4%
	Imports Only	2,851,351	2,048,630	802,720	8.2%	11.9%	4.7%
	INCs Only	1,294,424	406,287	787,973	3.7%	2.4%	4.6%
	Combination with INCs	850,941	527,546	323,395	2.5%	3.1%	1.9%
	Combination without INCs	22,519	19,628	2,892	0.1%	0.1%	0.0%
Generators		10,110,536	4,523,501	5,587,035	29.2%	26.4%	32.4%
Total		34,639,335	17,152,300	17,241,345	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category for the first three months of 2013 and the first three months of 2014. During the first three months of 2014, 91.0 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 27.8 percentage points from 63.2 percent in the first three months of 2013.

Table 4-17 Energy uplift credits by category: January through March 2013 and 2014

Category	Type	Jan - Mar 2013	Jan - Mar 2014	Change	Percentage Change	Jan - Mar 2013 Share	Jan - Mar 2014 Share
Day-Ahead	Generators	$17,357,053	$50,992,232	$33,635,179	193.8%	6.7%	6.9%
	Imports	$0	$2	$2	NA	0.0%	0.0%
	Load Response	$0	$167,092	$167,092	NA	0.0%	0.0%
Balancing	Canceled Resources	$27,776	$6,123	($21,653)	(78.0%)	0.0%	0.0%
	Generators	$140,301,039	$568,760,029	$428,458,990	305.4%	54.2%	77.2%
	Imports	$33,538	$120,363	$86,824	258.9%	0.0%	0.0%
	Load Response	$853	$5,607	$4,754	557.6%	0.0%	0.0%
	Local Constraints Control	$18,303	$835,712	$817,410	4,466.0%	0.0%	0.1%
	Lost Opportunity Cost	$23,339,277	$101,086,896	$77,747,620	333.1%	9.0%	13.7%
Reactive Services	Day-Ahead	$48,309,209	$5,404,256	($42,904,952)	(88.8%)	18.7%	0.7%
	Local Constraints Control	$0	$27,067	$27,067	NA	0.0%	0.0%
	Lost Opportunity Cost	$105,781	$87,728	($18,054)	(17.1%)	0.0%	0.0%
	Reactive Services	$7,164,366	$1,802,345	($5,362,021)	(74.8%)	2.8%	0.2%
	Synchronous Condensing	$0	$183,531	$183,531	NA	0.0%	0.0%
Synchronous Condensing		$1,873	$54,736	$52,863	2,821.7%	0.0%	0.0%
Black Start Services	Day-Ahead	$21,663,650	$5,484,816	($16,178,834)	(74.7%)	8.4%	0.7%
	Balancing	$589,796	$2,060,634	$1,470,839	249.4%	0.2%	0.3%
	Testing	$18,460	$11,028	($7,432)	(40.3%)	0.0%	0.0%
Total		$258,930,974	$737,090,198	$478,159,224	184.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type for the first three months of 2013 and the first three months of 2014. The increase in energy uplift in the first three months of 2014 compared to the first three months of 2013 was due to credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal). Credits to these units increased $500.7 million or 318.3 percent mainly because these units' offers were impacted by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $22.8 million.

Table 4-18 Energy uplift credits by unit type: January through March 2013 and 2014

Unit Type	Jan - Mar 2013	Jan - Mar 2014	Change	Percentage Change	Jan - Mar 2013 Share	Jan - Mar 2014 Share
Combined Cycle	$113,302,094	$379,207,339	$265,905,246	234.7%	43.8%	51.5%
Combustion Turbine	$35,382,276	$174,719,698	$139,337,422	393.8%	13.7%	23.7%
Diesel	$3,632,870	$1,850,423	($1,782,447)	(49.1%)	1.4%	0.3%
Hydro	$416	$135	($281)	(67.5%)	0.0%	0.0%
Nuclear	$0	$166,104	$166,104	0.0%	0.0%	0.0%
Steam - Coal	$91,920,814	$72,341,970	($19,578,845)	(21.3%)	35.5%	9.8%
Steam - Other	$8,618,485	$104,097,683	$95,479,198	1,107.8%	3.3%	14.1%
Wind	$6,039,628	$4,413,782	($1,625,846)	(26.9%)	2.3%	0.6%
Total	$258,896,583	$736,797,134	$477,900,551	184.6%	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first three months of 2014. Combined cycle units received 62.8 percent of the day-ahead generator credits in the first three months of 2014, 10.0 percentage points higher than the share received in the first three months of 2013. Combined cycle units received 59.8 percent of the balancing generator credits in the first three months of 2014, 9.9 percentage points lower than the share received in the first three months of 2013. Combustion turbines and diesels received 61.5 percent of the lost opportunity cost credits in the first three months of 2014, 3.3 percentage points lower than the share received in the first three months of 2013.

Table 4-19 Energy uplift credits by unit type: January through March 2014

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	62.8%	59.8%	0.0%	0.0%	6.5%	5.3%	0.0%	0.0%
Combustion Turbine	20.0%	17.7%	100.0%	100.0%	60.7%	18.6%	99.8%	0.2%
Diesel	0.2%	0.1%	0.0%	0.0%	0.8%	2.2%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Steam - Coal	13.7%	4.4%	0.0%	0.0%	27.2%	73.9%	0.0%	99.8%
Steam - Others	3.4%	18.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	4.3%	0.0%	0.0%	0.0%
Total	$50,992,232	$568,760,029	$6,123	$835,712	$101,086,896	$7,504,927	$54,736	$7,556,479

Table 4-19 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first three months of 2014, coal units received 73.9 percent of all reactive services credits, 5.5 percentage points lower than the share received in the first three months of 2013. Coal units received 99.8 percent of all black start services credits.

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating characteristics, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it impossible for competition to affect these payments.

The concentration of energy uplift credits is first examined by analyzing the characteristics of the top 10 units receiving energy uplift credits. The focus on the top 10 units is illustrative.

The concentration of energy uplift credits in the top 10 units remains high in the first three months of 2014. Table 4-20 shows that the top 10 units receiving total energy uplift credits, which make up less than one percent of all units in PJM's footprint, received 42.8 percent of total energy uplift credits in the first three months of 2014, compared to 48.1 percent in the first three months of 2013.

Table 4-20 Top 10 energy uplift credits units (By percent of total system): January through March 2013 and 2014

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan - Mar 2013	48.1%	0.7%
Jan - Mar 2014	42.8%	0.7%

Table 4-21 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-21 Top 10 units and organizations energy uplift credits: January through March 2014

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$27,921,072	54.8%	$43,310,510	84.9%
Balancing	Canceled Resources	$6,123	100.0%	$6,123	100.0%
	Generators	$296,848,508	52.2%	$512,598,955	90.1%
	Local Constraints Control	$835,712	100.0%	$835,712	100.0%
	Lost Opportunity Cost	$24,933,452	24.7%	$78,938,252	78.1%
Reactive Services		$5,414,618	72.1%	$7,470,071	99.5%
Synchronous Condensing		$54,400	99.4%	$54,736	100.0%
Black Start Services		$6,894,779	91.2%	$7,556,479	100.0%
Total		$315,409,978	42.8%	$615,706,457	83.6%

Table 4-22 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2014, 10.8 percent of all credits paid to these units were allocated to deviations while the remaining 89.2 percent were paid for reliability reasons.

Table 4-22 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through March 2014

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$264,889,927	$0	$0	$20,751,872	$11,206,709	$0	$296,848,508
Share	89.2%	0.0%	0.0%	7.0%	3.8%	0.0%	100.0%

In the first three months of 2014, concentration in all energy uplift credit categories was high.[11,12] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-23 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 4889, for balancing operating reserve credits to generators was 2919, for lost opportunity cost credits was 3647 and for reactive services credits was 7395.

Table 4-23 Daily energy uplift credits HHI: January through March 2014

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	4889	1409	10000	100.0%	36.4%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	99.9%
Balancing	Canceled Resources	8464	6054	10000	100.0%	100.0%
	Generators	2919	896	8994	94.8%	26.5%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	86.3%
	Lost Opportunity Cost	3647	632	10000	100.0%	14.3%
Reactive Services		7395	2988	10000	100.0%	52.0%
Synchronous Condensing		10000	10000	10000	100.0%	97.2%
Black Start Services		6451	3336	10000	100.0%	99.8%
Total		1832	616	6725	81.7%	20.8%

Economic and Noneconomic Generation[13]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 4-24 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating

11 See Section 3, "Energy Market" at "Market Concentration" for a complete discussion of concentration ratios and the Herfindahl-Hirshman Index (HHI).
12 Table 4-23 excludes local constraints control categories.
13 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In the first three months of 2014, 35.7 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 34.6 percent of the real-time generation was eligible for balancing operating reserve credits.[14]

Table 4-24 Day-ahead and real-time generation (GWh): January through March 2014

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	225,102	80,392	35.7%
Real-Time	219,999	76,212	34.6%

Table 4-25 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first three months of 2014, 90.4 percent of the day-ahead generation eligible for operating reserve credits was economic and 74.2 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-25 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through March 2014

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	72,672	7,719	90.4%	9.6%
Real-Time	56,547	19,665	74.2%	25.8%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In the first three months of 2014, 5.1 percent of the day-ahead generation eligible for operating reserve credits received credits and 6.5 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-26 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through March 2014

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	80,392	4,125	5.1%
Real-Time	76,212	4,967	6.5%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[15] Participants can submit

14 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

15 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM Presentation to the Market Implementation Committee (October 12, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.

units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[16] Units scheduled as must run by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first three months of 2014, 4.0 percent of the total day-ahead generation was scheduled as must run by PJM, 0.1 percentage points lower than the first three months of 2013.[17]

Table 4-27 Day-ahead generation scheduled as must run by PJM (GWh): 2013 and 2014

	2013			2014		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	72,681	2,907	4.0%	81,479	2,627	3.2%
Feb	65,632	2,474	3.8%	70,942	3,404	4.8%
Mar	67,940	3,178	4.7%	72,681	2,894	4.0%
Apr	57,570	2,522	4.4%			
May	61,169	2,848	4.7%			
Jun	68,452	3,724	5.4%			
Jul	78,639	4,395	5.6%			
Aug	73,783	3,678	5.0%			
Sep	64,757	3,162	4.9%			
Oct	62,134	2,940	4.7%			
Nov	63,827	2,675	4.2%			
Dec	73,112	2,612	3.6%			
Total (Jan - Mar)	206,252	8,559	4.1%	225,102	8,926	4.0%
Total	809,695	37,115	4.6%	225,102	8,926	4.0%

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-28 shows the total day-ahead generation scheduled as must run by PJM by category. In the first three months of 2014, 21.0 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 6.1 percent was generation from units scheduled to provide black start services, 3.9 percent was generation from units scheduled to provide reactive services and 11.0 percent was generation paid normal day-ahead operating reserve credits. The remaining 79.0 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

16 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version April 1, 2014) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.
17 PJM increased the amount of generation scheduled as must run on September 13, 2012. See the *2012 State of the Market Report for PJM: Volume II*, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

Table 4-28 Day-ahead generation scheduled as must run by PJM by category (GWh): 2014

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	216	157	232	2,022	2,627
Feb	84	30	428	2,862	3,404
Mar	242	162	325	2,166	2,894
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Total	543	349	985	7,049	8,926
Share	6.1%	3.9%	11.0%	79.0%	100.0%

Total day-ahead operating reserve credits in the first three months of 2014 were $51.0 million, of which $16.9 million or 33.2 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify and classify all reasons for paying operating reserve credits in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to inform all market participants of the reason for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.[18] The overall goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in the first three months of 2014. Table 4-29 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.2 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.7 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 1.0 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 4.4 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 14.6 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had a 21.5 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 91.3 percent of all charges were allocated in control zones, 1.9 percent in hubs and aggregates and 6.8 percent in interfaces.

18 The classification could occur via defined logging codes for dispatchers. That would create data that could be analyzed by the MMU and summarized for participants.

Table 4-29 Geography of regional charges and credits: January through March 2014[19]

Location		Charges	Credits	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$8,354,413	$4,867,819	($3,486,594)	1.2%	0.7%	1.0%	0.0%
	AEP - EKPC	$126,374,139	$30,694,588	($95,679,550)	17.5%	4.3%	28.0%	0.0%
	AP - DLCO	$52,163,722	$13,700,588	($38,463,134)	7.2%	1.9%	11.2%	0.0%
	ATSI	$50,483,603	$17,201,999	($33,281,603)	7.0%	2.4%	9.7%	0.0%
	BGE - Pepco	$56,477,142	$34,883,310	($21,593,832)	7.8%	4.8%	6.3%	0.0%
	ComEd - External	$72,647,464	$24,040,101	($48,607,363)	10.1%	3.3%	14.2%	0.0%
	DAY - DEOK	$39,679,375	$2,611,494	($37,067,882)	5.5%	0.4%	10.8%	0.0%
	Dominion	$78,029,789	$100,639,137	$22,609,348	10.8%	14.0%	0.0%	6.6%
	DPL	$18,471,964	$40,014,262	$21,542,298	2.6%	5.6%	0.0%	6.3%
	JCPL	$18,000,804	$62,010,249	$44,009,445	2.5%	8.6%	0.0%	12.9%
	Met-Ed	$14,636,818	$62,823,010	$48,186,191	2.0%	8.7%	0.0%	14.1%
	PECO	$33,396,232	$88,556,690	$55,160,458	4.6%	12.3%	0.0%	16.1%
	PENELEC	$17,975,632	$19,337,594	$1,361,962	2.5%	2.7%	0.0%	0.4%
	PPL	$38,246,884	$113,864,123	$75,617,238	5.3%	15.8%	0.0%	22.1%
	PSEG	$31,962,712	$105,600,315	$73,637,602	4.4%	14.6%	0.0%	21.5%
	RECO	$1,064,721	$0	($1,064,721)	0.1%	0.0%	0.3%	0.0%
	All Zones	$657,965,417	$720,845,280	$62,879,863	91.3%	100.0%	81.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$6,224,190	$0	($6,224,190)	0.9%	0.0%	1.8%	0.0%
	Dominion	$765,493	$0	($765,493)	0.1%	0.0%	0.2%	0.0%
	Eastern	$148,259	$0	($148,259)	0.0%	0.0%	0.0%	0.0%
	New Jersey	$487,558	$0	($487,558)	0.1%	0.0%	0.1%	0.0%
	Ohio	$16,643	$0	($16,643)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$268,442	$0	($268,442)	0.0%	0.0%	0.1%	0.0%
	Western	$5,976,694	$0	($5,976,694)	0.8%	0.0%	1.7%	0.0%
	RTEP B0328 Source	$4	$0	($4)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$13,887,284	$0	($13,887,284)	1.9%	0.0%	4.1%	0.0%
Interfaces	CPLE Imp	$0	$0	($0)	0.0%	0.0%	0.0%	0.0%
	Hudson	$1,578,372	$0	($1,578,372)	0.2%	0.0%	0.5%	0.0%
	IMO	$4,795,544	$0	($4,795,544)	0.7%	0.0%	1.4%	0.0%
	Linden	$1,180,891	$0	($1,180,891)	0.2%	0.0%	0.3%	0.0%
	MISO	$9,894,769	$0	($9,894,769)	1.4%	0.0%	2.9%	0.0%
	Neptune	$2,514,069	$0	($2,514,069)	0.3%	0.0%	0.7%	0.0%
	NIPSCO	$2	$0	($2)	0.0%	0.0%	0.0%	0.0%
	Northwest	$48,094	$0	($48,094)	0.0%	0.0%	0.0%	0.0%
	NYIS	$9,168,617	$0	($9,168,617)	1.3%	0.0%	2.7%	0.0%
	OVEC	$3,030,430	$0	($3,030,430)	0.4%	0.0%	0.9%	0.0%
	South Exp	$2,729,925	$0	($2,729,925)	0.4%	0.0%	0.8%	0.0%
	South Imp	$14,172,230	$0	($14,172,230)	2.0%	0.0%	4.1%	0.0%
	All Interfaces	$49,112,944	$120,365	($48,992,579)	6.8%	0.0%	14.4%	0.0%
	Total	$720,965,645	$720,965,645	$0	100.0%	100.0%	100.0%	100.0%

19 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-29 does not include synchronous condensing, local constraint control, black start services and reactive services charges and credits since these are allocated zonally.

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 4-30 shows the geography of reactive services charges. In the first three months of 2014, 95.8 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 0.5 percent were paid by real-time load in multiple zones and 3.7 percent were paid by real-time load across the entire RTO. In the first three months of 2014, the top three zones accounted for 81.5 percent of all the reactive services charges allocated to single zones.

Table 4-30 Geography of reactive services charges: January through March 2014[20]

Location	Charges	Share of Charges
Single Zone	$7,161,624	95.8%
Multiple Zones	$41,118	0.5%
Entire RTO	$275,118	3.7%
Total	$7,477,860	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.9 percent of all the black start services costs in the first three months of 2014. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in three control zones accounted for all synchronous condensing costs in the first three months of 2014.

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[21] If a unit generating in real time with an offer price lower than the real-time LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue, the unit will receive a credit for LOC based on the desired output. For purposes of this report, this LOC will be referred as real-time LOC.

In the first three months of 2014, LOC credits increased by $77.7 million or 333.1 percent compared to the first three months of 2013. The increase of $77.7 million is comprised of an increase of $46.7 million in day-ahead LOC and an increase of $31.0 million in real-time LOC. Table 4-33 shows the monthly composition of LOC credits in 2013 and the first three months of 2014. The increase in LOC credits was primarily a result of higher real-time energy prices during hours for which the units had been scheduled day ahead and should have been called in real time but were not and units that were manually dispatched down in order to maintain system reliability during periods of high energy prices. The impact of high real-time energy prices was partially offset by less generation receiving LOC credits in the first three months of 2014 compared to the first three months of 2013. In the first three months of 2014, 16.5 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 31.2 percentage points lower than in the first three months of 2013.

20 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services, synchronous condensing or certain other ancillary services because of confidentiality requirements. See PJM. Manual 33: Administrative Services for the PJM Interconnection Agreement, Revision 10 (April 11, 2014).

21 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market minus the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not committed in real time incurs balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

Table 4-31 Monthly lost opportunity cost credits: 2013 and 2014

	2013			2014		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$8,728,322	$2,752,980	$11,481,302	$47,562,606	$29,609,927	$77,172,533
Feb	$2,049,518	$2,681,143	$4,730,662	$6,049,668	$5,151,827	$11,201,495
Mar	$4,803,277	$2,324,036	$7,127,313	$8,659,232	$4,053,636	$12,712,868
Apr	$3,893,268	$1,888,605	$5,781,873			
May	$5,266,582	$3,251,694	$8,518,276			
Jun	$6,200,721	$826,758	$7,027,479			
Jul	$16,300,953	$3,191,321	$19,492,274			
Aug	$5,449,177	$234,782	$5,683,959			
Sep	$6,377,820	$4,596,267	$10,974,087			
Oct	$2,455,137	$630,186	$3,085,323			
Nov	$1,365,945	$778,925	$2,144,870			
Dec	$535,311	$573,207	$1,108,518			
Total (Jan - Mar)	$15,581,117	$7,758,160	$23,339,277	$62,271,506	$38,815,390	$101,086,896
Share (Jan - Mar)	66.8%	33.2%	100.0%	61.6%	38.4%	100.0%
Total	$63,426,030	$23,729,905	$87,155,935	$62,271,506	$38,815,390	$101,086,896
Share	72.8%	27.2%	100.0%	61.6%	38.4%	100.0%

Table 4-32 Day-ahead generation from combustion turbines and diesels (GWh): 2013 and 2014

	2013			2014		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	886	633	561	2,115	846	358
Feb	430	206	173	763	304	153
Mar	809	395	282	976	233	126
Apr	684	325	256			
May	1,019	387	260			
Jun	1,273	696	440			
Jul	2,935	947	748			
Aug	1,767	778	544			
Sep	1,213	480	295			
Oct	929	451	267			
Nov	578	213	120			
Dec	426	109	49			
Total (Jan - Mar)	2,125	1,233	1,015	3,854	1,383	637
Share (Jan - Mar)	100.0%	58.0%	47.8%	100.0%	35.9%	16.5%
Total	12,949	5,620	3,994	3,854	1,383	637
Share	100.0%	43.4%	30.8%	100.0%	35.9%	16.5%

Table 4-32 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. Table 4-32 shows that while day-ahead scheduled generation from CTs and diesels increased 1,729 GWh or 81.3 percent in the first three months of 2014 compared to the first three months of 2013, the generation that received LOC credits was reduced by 378 GWh or 37.3 percent.

In the first three months of 2014, the top three control zones in which generation received LOC credits, AEP, Dominion and PENELEC, accounted for 58.2 percent of all LOC credits, 44.8 percent of all the day-ahead generation from combustion turbines and diesels, 50.9 percent of all day-ahead generation not committed in real time by PJM from those unit types and 60.2 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled day ahead to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for LOC credits for hours 10, 11, 17 and 18. Table 4-33 shows the LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 4-33 shows that in the first three months of 2014, $28.4 million or 45.5 percent of all

LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 37.4 percentage points lower than the first three months of 2013.

Table 4-33 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2013 and 2014

	2013			2014		
	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total
Jan	$8,081,096	$647,226	$8,728,322	$21,107,023	$26,455,583	$47,562,606
Feb	$1,860,546	$188,972	$2,049,518	$3,653,270	$2,396,398	$6,049,668
Mar	$2,985,098	$1,818,180	$4,803,277	$3,603,333	$5,055,898	$8,659,232
Apr	$2,476,452	$1,416,816	$3,893,268			
May	$3,615,804	$1,650,778	$5,266,582			
Jun	$4,758,076	$1,442,645	$6,200,721			
Jul	$7,462,411	$8,838,541	$16,300,952			
Aug	$3,378,510	$2,070,667	$5,449,177			
Sep	$4,200,542	$2,177,278	$6,377,820			
Oct	$2,167,106	$288,031	$2,455,137			
Nov	$846,109	$519,836	$1,365,945			
Dec	$195,648	$339,663	$535,311			
Total (Jan - Mar)	$12,926,740	$2,654,377	$15,581,117	$28,363,626	$33,907,879	$62,271,506
Share (Jan - Mar)	83.0%	17.0%	100.0%	45.5%	54.5%	100.0%
Total	$42,027,399	$21,398,631	$63,426,030	$28,363,626	$33,907,879	$62,271,506
Share	66.3%	33.7%	100.0%	45.5%	54.5%	100.0%

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-34 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-34 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first three months of 2014, 50.1 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 49.9 percent was noneconomic.

Table 4-34 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2013 and 2014[22]

	2013			2014		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	544	121	664	365	359	725
Feb	171	53	224	134	159	293
Mar	269	144	413	127	105	232
Apr	225	93	318			
May	228	129	357			
Jun	364	272	635			
Jul	713	202	915			
Aug	436	275	711			
Sep	293	166	459			
Oct	256	175	431			
Nov	131	64	195			
Dec	35	59	94			
Total (Jan - Mar)	984	318	1,301	627	623	1,250
Share (Jan - Mar)	75.6%	24.4%	100.0%	50.1%	49.9%	100.0%
Total	3,665	1,753	5,418	627	623	1,250
Share	67.6%	32.4%	100.0%	50.1%	49.9%	100.0%

Black Start Service Units

Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the automatic load rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option can remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[23]

In the first three months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $7.5 million, and 93.3 percent of these costs was paid by peak transmission use in the AEP Control Zone while the remaining 6.7 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP Control Zone. Load in the AEP Control Zone paid an average of $3.42 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.02 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP Control Zone. PJM awarded all viable solutions from the last RFP.[24] PJM also approved new rules concerning black start service procurement. Resources selected through the new process are expected to provide black start service as of April 1, 2015.[25,26]

Reactive / Voltage Support Units

Closed Loop Interfaces

In 2013, PJM began to develop solutions to improve the incorporation of reactive constraints into energy prices. One of PJM's solutions was to create interfaces that could be used in such a way that units needed for reactive support could set the energy price. These closed loop interfaces would be used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of

22 The total generation in Table 4-34 is lower than the day-ahead generation not requested in real time in Table 4-32 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-34 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

23 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

24 See PJM. "Item 3: Black Start RFP Status," PJM Presentation to the System Restoration Strategy Task Force (June 14, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.

25 See the *2013 State of the Market Report for PJM, Volume II*, Section 10, "Ancillary Services" at "Black Start Service".

26 See PJM. Manual 14D: Generator Operational Requirement, Revision 27 (April 11, 2014) at "Section 10: Black Start Generation Procurement".

buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside of the loop with the rest of PJM. PJM has currently defined four closed loop interfaces: ComEd, Cleveland, ATSI and BC/PEPCO.[27,28]

Under the status quo, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. Under the proposed solution these units could be made marginal even when not needed for energy, by adjusting the limit of the closed loop interface. This would create congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by making these units marginal to the extent possible, hence reducing energy uplift costs.

PJM proposed a Seneca Interface but later announced that an alternate solution to the reactive issue was developed through changes in the transmission system topology which minimized the need for reactive support in the area.[29]

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid disruption of the way in which the transmission network is modeled. The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market before their implementation to avoid unintended consequences.

27 See PJM. Manual 3: Transmission Operations, Revision 44 (November 1, 2013) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)" for a description of these interfaces, except for the ATSI interface.
28 See the ATSI Interface definition at <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>.
29 See PJM. "Item 02 - Action Item Responses," question 19. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140304/20140304-item-02-action-item-responses.ashx>.

AP South / Bedington – Black Oak Reactive Support

Beginning in 2012 and during almost all 2013, a set of units located in the BGE and Pepco control zones were scheduled and committed to provide reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces. These units were scheduled as must run in the Day-Ahead Energy Market whenever they would not clear the market based on economics and were selected by PJM to provide reactive support.

On December 24, 2013, PJM began to schedule less generation from units in the BGE and Pepco control zones in order to reduce energy uplift costs associated with the reactive support provided by these units to the 500 KV transmission lines that comprise the AP South and Bedington – Black Oak reactive transfer interfaces.[30] At the same time, PJM restarted modeling the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy Markets and reduced FMU adders to reactive units.[31] These actions eliminated energy uplift costs for the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 24, 2013.

In the first three months of 2014, the total scheduled generation from these units increased by 2,482 GWh or 62.9 percent when compared to the first three months of 2013. The units have received a 76.5 percent reduction in energy uplift credits in the Day-Ahead Energy Market compared to the amount paid in the first three months of 2013. These units were more economic in the first three months of 2014 primarily as a result of higher LMPs in the first three months of 2014.[32] The weighted average day-ahead LMP at these units' buses in the first three months of 2014 was $135.99 per MWh, $90.48 per MWh higher than the average in the first three months of 2013. Reduced FMU adders for these reactive units also significantly reduced the offers and energy uplift credits of these units.

30 See PJM "Reactive Charges Update," PJM Presentation at the Market Implementation Committee (January 8, 2014) <http://www.pjm.com/committees-and-groups/committees/mic.aspx>.
31 In 2012, the BC/PEPCO interface was modeled in the Day-Ahead Energy Market starting on August 22, 2012. In 2013, the interface was stopped being modeled on September 25, 2013 and was resumed on December 27, 2013. In real time the interface was only modeled twice in 2012 and once in 2013 (before December 24). After December 24, 2013, the interface was modeled every day.
32 See Section 3, "Energy Market" at "Prices" for the components of the day-ahead and real-time LMP and their contribution in the first three months of 2014 and the first three months of 2013.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Current confidentiality rules do not appear to allow posting data for three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[33]

Energy uplift charges are out of market, non-transparent payments made to resources operating at PJM's direction. Energy uplift charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the resources receiving energy uplift payments. Uplift charges are not included in the transmission planning process meaning that transmission solutions are not considered. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and the absence of relevant information creates a barrier to entry. The MMU recommends that PJM revise the current energy uplift confidentiality rules in order to allow the disclosure of energy uplift credits by zone, by owner and by resource.

Energy Uplift Recommendations

Credits Recommendations

Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[34]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss or not until the unit actually operates. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their profits in real time.

33 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 10 (April 11, 2014), Market Data Posting.

34 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net non-synchronized reserve revenues and reactive services revenues.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or not loss do not have a reduction in energy uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units the MMU recommended enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[35] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[36] The elimination of the day-ahead operating reserve category also ensures that units are always made whole based on their actual operation and actual revenues. The MMU supports the PJM proposal of eliminating the day-ahead operating reserve category.

The MMU calculated the impact of this recommendation in 2013 and the first three months of 2014. In 2013 and the first three months of 2014, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $77.0 million or 12.9 percent ($6.6 million paid to units providing reactive support, $12.1 million paid to units providing black start support and the remaining $58.2 million paid to units as day-ahead and balancing operating reserves).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. Under the current rules the charges categorized as day-ahead operating reserve charges would be allocated to deviations or real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the Regulation Market. The filing included four elements: implement the TPS test in the regulation market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and non-synchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation.

35 See *2013 State of the Market Report for PJM, Volume II*, Section 4, "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

36 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 8, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140408/20140408-explanation-of-pjm-proposals.ashx>.

A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price-taker, but in the Energy Market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation, the result is increased energy uplift.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2013 and the first three months of 2014, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $20.8 million, of which $17.3 million or 83.0 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.[37]

Self-Startup

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[38] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled are price takers in both the Day-Ahead and Real-Time Energy Markets unless self-scheduled units elect to submit a fixed energy amount per hour or a minimum must run amount from which the unit may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

In some cases, units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup cost. The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommends four modifications.[39]

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the LOC in the energy market. The MMU recommends that the LOC in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. This recommendation was proposed at the MIC.
- **No load and startup costs:** Current rules do not include in the calculation of LOC credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not committed in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation was proposed at the MIC.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the LOC calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater

37 These estimates take into account the elimination of the day-ahead operating reserve category.

38 See "PJM eMkt Users Guide," Section Managing Unit Data (version April 1, 2014) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

39 See "LOC Session MA Energy LOC Proposal," MMU Presentation to the Market Implementation Committee (October 19, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121019/20121019-loc-session-ma-energy-loc-proposal.ashx>.

than the day-ahead LMP. In the Day-Ahead Energy Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives LOC credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits if necessary. If the unit is not committed in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual LOC. The MMU recommends eliminating the use of the day-ahead LMP to calculate LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

- **Offer Curve:** Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the LOC in the PJM Energy Markets for units scheduled in day ahead but which are reduced, suspended or not committed in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real time by PJM should be paid LOC based on the area between the real-time LMP and their offer curve between the actual and desired output points. Units scheduled in day ahead and not dispatched in real time should be paid LOC based on the area between the real-time LMP and their offer curve between zero output and scheduled output points. The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy LOC.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' schedule on which it is committed.

Table 4-35 shows the impact that each of these changes would have had on the LOC credits in the Energy Market in the first three months of 2014, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $9.8 million, or 9.7 percent, if all these changes had been implemented.[40]

Table 4-35 Impact on energy market lost opportunity cost credits of rule changes: January through March 2014

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$38,815,390	$62,271,506	$101,086,896
Impact 1: Committed Schedule	$637,882	$1,693,239	$2,331,121
Impact 2: Eliminating DA LMP	NA	($2,510,892)	($2,510,892)
Impact 3: Using Offer Curve	($1,153,896)	$3,232,205	$2,078,309
Impact 4: Including No Load Cost	NA	($8,625,149)	($8,625,149)
Impact 5: Including Startup Cost	NA	($3,059,371)	($3,059,371)
Net Impact	($516,014)	($9,269,967)	($9,785,981)
Credits After Changes	$38,299,376	$53,001,538	$91,300,915

Allocation Recommendations

Up-to Congestion Transactions

Up-to congestion transactions do not pay energy uplift charges. An up-to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up-to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged energy uplift.

The MMU calculated the impact on energy uplift rates if up-to congestion transactions had paid energy uplift charges based on deviations in the

40 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

same way that increment offers and decrement bids do along with other recommendations that impact the total costs of energy uplift and its allocation.

The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. Up-to congestion transactions would have paid an average rate between $0.215 and $0.879 per MWh in 2013 and between $1.037 and $1.270 per MWh in the first three months of 2014 if the MMU's recommendations regarding energy uplift had been in place.[41,42]

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of balancing operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[43] Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids also incur deviations. These transactions are grouped in the demand and supply categories.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system. Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped into two categories, demand and supply and aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are in the same location at the same hour.[44] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The impact of eliminating the use of internal bilateral transactions in the calculation of deviations use to allocated balancing operating reserve charges has been aggregated with the impacts of other recommendations.

Con Edison – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the wheeling contracts between Con-Ed and PSEG.[45] These units are often run out of merit and receive substantial day-ahead and balancing operating reserve credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

41 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.

42 This analysis assumes that not all costs associated with units providing support to the Con Edison – PSEG wheeling contracts would be reallocated under the MMU's proposal. The *2013 State of the Market Report for PJM* analysis assumed that all such costs would be reallocated. This analysis also assumes that only 50 percent of all cleared up-to congestion transactions would have cleared had this recommendation been in place. The *2013 State of the Market Report for PJM* analysis showed that more than 66.7 percent of up-to congestion transactions would have remained under the MMU proposal.

43 See OATT 3.2.3 (o) for a complete description of how generators deviate.

44 Locations can be control zones, hubs, aggregates and interfaces. See the *2013 State of the Market Report for PJM, Volume II*, Section 4, "Energy Uplift" at "Energy Uplift" pp. 124-129 for a description of balancing operating reserve locations.

45 See the *2013 State of the Market Report for PJM, Volume II*, Section 9, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[46] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In the first three months of 2014, units providing reactive services were paid $0.9 million in balancing operating reserve credits in order to cover their total energy offer. In 2012 and 2013, this misallocation was $26.7 million, for a total of $27.6 million in the last two years and three months.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports in the allocation of the cost of providing reactive support to the 500 kV system or above. Currently only real-time RTO load pays.[47]

Allocation Proposal

The day-ahead operating reserve category elimination and other MMU recommendations require enhancements to the current energy uplift allocation methodology.

46 OATT Attachment K - Appendix § 3.2.3B (f).

47 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

The current methodology allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category shifts these costs to the balancing operating reserve category which could be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules. The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services), which would be allocated to day-ahead load, day-ahead interchange transactions and virtual transactions. All these transaction types have an impact on the outcome of the day-ahead scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time based on the current deviation categories with the addition of up-to congestion and wheeling transactions and the exclusion of offsets based on internal bilateral transactions. These costs should be allocated to the current deviation categories whenever the units receiving energy uplift payments are committed before the operating day.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real-time should be allocated to deviations based on the proposed definition of deviations. LOC paid to units reduced for reliability in real time and payments to canceled resources should be allocated to physical deviations.

The MMU recommends allocating energy uplift payments to units committed during the operating day (CTs) to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources that result in the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load plus real-time exports independently of the timing of the commitment.

Table 4-36 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-36 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Unit Not Scheduled Day Ahead and Committed in Real Time	Balancing Operating Reserve	Committed before the operating day for reliability	Real-Time Load and Real-Time Exports
		Committed before the operating day to meet forecasted load and reserves	Deviations
		Committed during the operating day and LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		Committed during the operating day and LMP > Offer for at least four intervals	Deviations
Units scheduled in the Day-Ahead Energy Market not committed in real time	LOC Credit	NA	Deviations
Units reduced for reliability in real time	LOC Credit	NA	Deviations
Units canceled before coming online	Cancellation Credit	NA	Deviations

Table 4-37 MMU energy uplift allocation proposal

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market and committed in real time	Day-Ahead Segment Make Whole Credit	NA	Day-Ahead Load, Day-Ahead Interchange Transactions and Virtual Transactions
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Real Time Segment Make Whole Credit	Committed before the operating day	Deviations
		Committed during the operating day	Physical Deviations
		Any commitment for reliability	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units scheduled in the Day-Ahead Energy Market not committed in real time	Day-Ahead LOC	NA	Deviations
Units reduced for reliability in real time	Real-Time LOC	NA	Physical Deviations
Units canceled before coming online	Cancellation Credit	NA	Physical Deviations

Table 4-37 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead load, day-ahead interchange transactions and virtual transactions. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Quantifiable Recommendations Impact

The MMU calculated the rates that participants would have paid in 2013 and the first three months of 2014 if all the MMU's recommendations on energy uplift had been in place. In order to avoid the release of confidential information, these impacts cannot be disaggregated by issue. These recommendations have been included in the analysis: day-ahead operating reserve elimination; net regulation revenues offset; implementation of the proposed changes to lost opportunity cost calculations; reallocation of operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts; elimination of internal bilateral transactions from the deviations calculation; allocation of energy uplift charges to up-to congestion transactions and the MMU energy uplift allocation proposal.

Table 4-38 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2013 and the first three months of 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.439 and $0.635 per MWh in the 2013 and the first three months of 2014, $2.946 and $5.928 per MWh less than the actual average rate paid. Up-to congestion transactions sourced in the Eastern Region and sinking in the Western Region would have paid an average rate of $0.547 and $1.154 per MWh in 2013 and the first three months of 2014. Table 4-38 shows the current and proposed averages energy uplift rates for all transactions.

Table 4-38 Current and proposed average energy uplift rate by transaction: 2013 and January through March 2014[48]

		2013		Jan - Mar 2014	
	Transaction	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Current Rates ($/MWh)	Proposed Rates ($/MWh)
East	INC	3.283	0.439	6.351	0.635
	DEC	3.385	0.439	6.563	0.635
	DA Load	0.102	0.019	0.212	0.089
	RT Load	0.076	0.059	1.697	1.652
	Deviation	3.283	1.205	6.351	3.245
West	INC	1.650	0.107	5.593	0.518
	DEC	1.752	0.107	5.805	0.518
	DA Load	0.102	0.019	0.212	0.089
	RT Load	0.056	0.039	1.682	1.637
	Deviation	1.650	0.690	5.593	3.042
UTC	East to East	NA	0.879	NA	1.270
	West to West	NA	0.215	NA	1.037
	East to/from West	NA	0.547	NA	1.154

January through March 2014 Energy Uplift Charges Increase

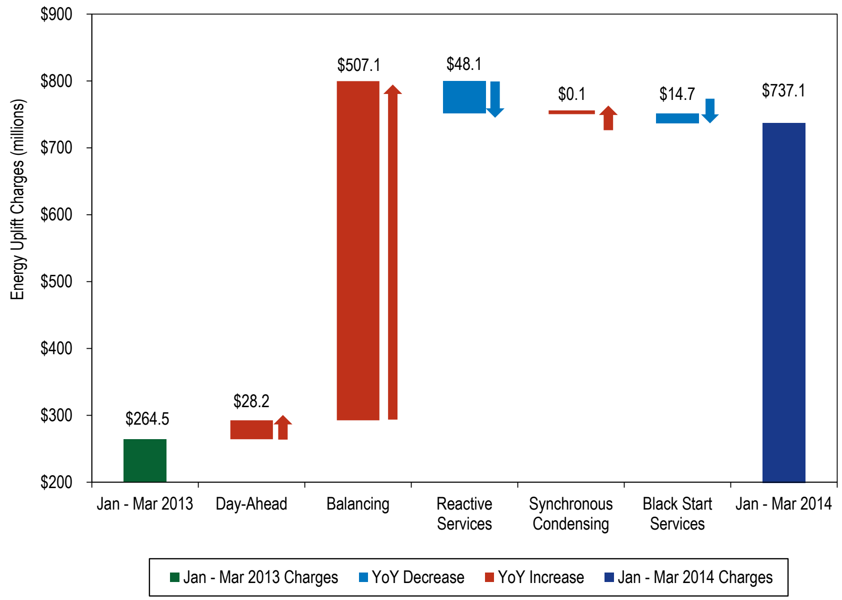
Energy uplift charges increased by $472.6 million, from $264.5 million in the first three months of 2013 to $737.1 million in the first three months of 2014. This change resulted from an increase of $507.1 million in balancing operating reserve charges, an increase of $28.2 million in day-ahead operating reserve charges and an increase of $0.1 million in synchronous condensing charges. These increases were partially offset by a decrease of $48.1 million in reactive services charges and a decrease of $14.7 million in black start services charges.

Figure 4-6 shows the net impact of each category on the change in total energy uplift charges from the first three months of 2013 level to the first three months of 2014 level. The outside bars show the first three months of 2013 total energy uplift charges (left side) and the first three months of 2014 total energy uplift charges (right side). The other bars show the change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in the first three months

48 The deviation transaction means load, interchange transactions, generators and DR deviations.

of 2014 compared to the first three months of 2013 (an increase of $28.0 million).

Figure 4-6 Energy uplift charges change from January through March 2013 to January through March 2014 by category



The combination of high natural gas prices, increased forced outage rates, natural gas supply inflexibility and PJM's need to operate the system in a conservative manner during the cold weather events resulted in high energy uplift charges in January 2014. These factors impacted both day-ahead and balancing operating reserve charges.

Figure 4-7 shows the net impact of different categories of day-ahead operating reserve. The outside bars show the first three months of 2013 day-ahead operating reserve charges (left side) and the first three months of 2014 day-ahead operating reserve charges (right side). The other bars show the change in each category. For example, the second bar from the left shows the change in unallocated congestion charges in the first three months of 2014 compared to the first three months of 2013 (a decrease of $5.8 million).

The largest impact on day-ahead operating reserves was from units that cleared in the Day-Ahead Energy Market and were economic for less than 50 percent of their scheduled run time, the rest of the time in each day the units were scheduled to run at a loss in the day-ahead market which resulted in energy uplift costs. In the first three months of 2014, day-ahead operating reserve credits paid to such units increased by $21.3 million from $3.7 million in the first three months of 2013.

The second largest impact on day-ahead operating reserve charges was the energy uplift payments to units that are regularly scheduled as must run by PJM in the Day-Ahead Energy Market in order to better match expected real time conditions. The high natural gas prices in January 2014 resulted in the increase in energy uplift payments to these units by $8.1 million in the first three months of 2014 compared to the first three months of 2013.

Figure 4-7 Day-ahead operating reserve charges change from January through March 2013 to January through March 2014 by category

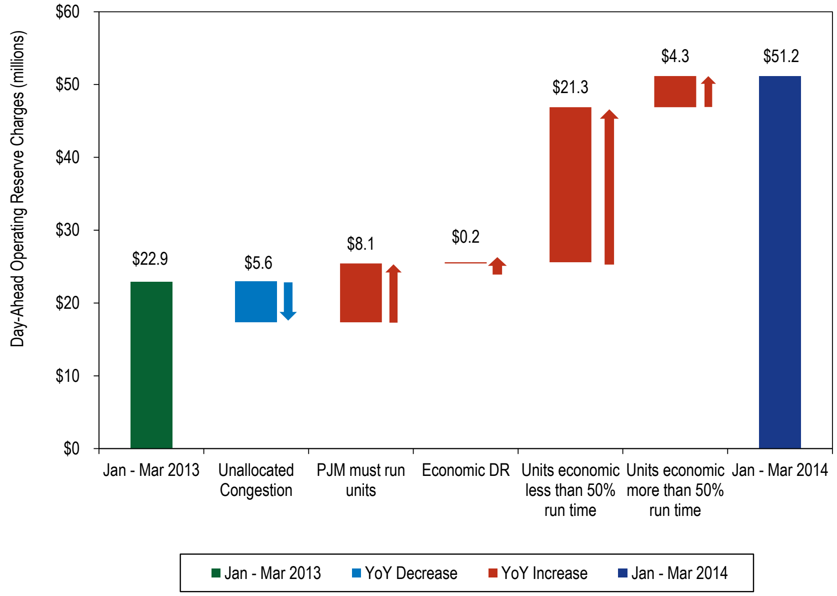
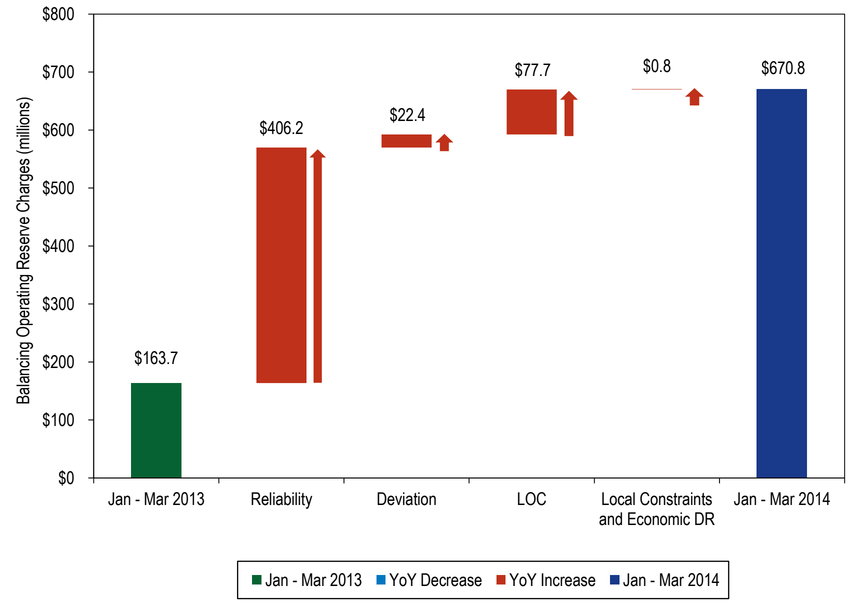


Figure 4-8 shows the net impact of different categories of balancing operating reserve. The outside bars show the first three months of 2013 balancing operating reserve charges (left side) and the first three months of 2014 balancing operating reserve charges (right side). The other bars show the change in each category. For example, the second bar from the left shows the change in balancing reliability charges in the first three months of 2014 compared to the first three months of 2013 (an increase of $406.2 million).

The largest impact on balancing operating reserve charges was credits paid to units committed for conservative operations with offers significantly higher than the LMP, primarily as a result of high natural gas prices. Energy uplift payments to units committed for reliability purposes before the operating day during the reliability analysis are allocated as balancing operating reserve charges for reliability.

The second largest impact on balancing operating reserve charges was credits for lost opportunity cost (LOC) to units scheduled in the Day-Ahead Energy Market and not committed in real time or to units reduced in real time. LOC compensation increased by $77.2 million in the first three months of 2014 compared to the first three months of 2013.

Figure 4-8 Balancing operating reserve charges change from January through March 2013 to January through March 2014 by category



Energy Uplift and Conservative Operations

PJM dispatchers committed a substantial number of units for conservative operations during the high load days of January 2014. In the first three months of 2014, 834.7 GWh were committed during the reliability analysis (before the operating day) for conservative operations on 23 days, 773.9 GWh or 12.7 times more than the 60.8 GWh committed for the same purposes in the first three months of 2013.

These units in the first three months of 2014 had high offers as a result of high natural gas prices and 97 percent of these units are located in the Eastern Region of PJM. During the peak hours of January these units were needed either to meet load, to provide additional reserves or to reduce operational uncertainty in general. During the peak hours, the units that received make whole payments were noneconomic by an average of $277.43 per MWh and by an average of $439.40 per MWh during off peak hours.[49,50] PJM's decision to keep running these units even when they were substantially noneconomic included uncertainty as to whether the units would restart, uncertainty about the ability of the units to procure natural gas and the inflexibility of natural gas procurement.

Figure 4-9 shows the average output in MW (on and off peak) on several critical January days from units committed for conservative operations and the average output in MW of other unit types. The figure shows (top figure) that on January 28, during peak hours, units committed for conservative operations produced 7,418 MW on average and reduced on average by only 1,748 MW to 5,671 MW during off peak hours, even though the units were noneconomic. The figure shows (middle figure) that on the same day, during peak hours, conventional thermal units (excluding hydro, nuclear, solar and wind and units committed for conservative operations) produced 81,899 MW on average, but were reduced on average by 7,248 MW to 74,651 MW during the off peak hours. The figure shows (bottom figure) that on the same day, during peak hours, hydro, nuclear, solar and wind units produced 38,043 MW on average and reduced on average by 1,636 MW to 36,408 MW during off peak hours.

The sum of the MW in each bar in the top, middle and bottom figures equals the average output produced by units internal to PJM for each day during peak and off peak periods.

A substantial part of the energy uplift associated with units committed for conservative operations was a result of the fact that these units were not flexible. These expensive, gas-fired units were not turned off during off peak hours when the units were not needed and the uplift payments were very large. If the units committed for conservative operations had been more flexible (for example, decommitting these units during off peak hours) the energy uplift cost in January would have been reduced. This explanation does not take account for output reductions due to forced outages or transmission constraints.

49 For the purposes of these analysis peak hours were defined as HE 8 through HE 11 and HE 18 through HE 21. The remaining 16 hours were defined as off peak hours.

50 The spread is calculated as the difference between the energy revenues plus net revenues used in the balancing operating reserve credit calculation subtracted by the hourly offer. The critical days used in this analysis were January 7, 8, 22, 23, 24, 25, and 28.

Figure 4-9 Critical January days peak and off peak output

Lost Opportunity Cost Credits

In 2013, LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not committed in real time began to decrease as a result of less generation from this type of units scheduled in day ahead in combination with PJM's implementation of a new tool to improve the commitment of combustion turbines (combustion turbine optimizer or CTO).

In January 2014, the commitment of units in the Day-Ahead Energy Market for conservative operations even when these units did not clear the Day-Ahead Energy Market increased the amount of generation from combustion turbines and diesels scheduled in the Day-Ahead Energy Market. Figure 4-10 shows the amount of generation in GWh committed by PJM before or during the operating day without having been scheduled in the Day-Ahead Energy Market and that also was paid balancing operating reserve credits. Figure 4-10 also shows the generation in GWh scheduled in the Day-Ahead Energy Market from combustion turbines and diesels that were not committed in real time and were paid lost opportunity cost credits. The figure shows for example that on January 22, 153.7 GWh were committed by PJM in real time (without being scheduled in the Day-Ahead Energy Market) while 67.4 GWh scheduled in the Day-Ahead Energy Market were not committed in real time.

Figure 4-10 BOR and LOC Generation: January through March 2014