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 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 services charges.[2]

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by 35.6 percent or $231.4 million in 2013 compared to 2012, from $650.8 million to $882.2 million. This change was the result of an increase of $263.5 million in reactive services charges, an increase of $78.2 million in black start services charges and an increase of $0.2 million in synchronous condensing charges. These increases were partially offset by a decrease of $48.9 million in day-ahead operating reserve charges and a decrease of $61.6 million in balancing operating reserve charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.079 per MWh. The day-ahead operating reserve rate including unallocated congestion charges averaged $0.103 per MWh. The balancing operating reserve reliability rates averaged $0.051, $0.030 and $0.004 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $0.863, $1.868 and $0.122 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $0.705 per MWh and the canceled resources rate averaged $0.003 per MWh.
- **Reactive Services Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $2.538, $1.900 and $0.690 per MWh. The reactive transfer interface support rate averaged $0.224 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 48.8 percent of all day-ahead generator credits and 49.1 percent of all balancing generator credits. Combustion turbines and diesels received 72.7 percent of the lost opportunity cost credits. Coal units received 87.1 percent of all reactive services credits.
- **Economic and Noneconomic Generation.** In 2013, 81.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Charges and Credits

- In 2013, 82.2 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, 5.9 percent by transactions at hubs and aggregates and 11.9 percent by transactions at interfaces.

Energy Uplift Issues

- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 38.0 percent of all credits. The top 10 organizations received 88.4 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5340, balancing operating reserves HHI was 3622, lost opportunity cost HHI was 4390 and reactive services HHI was 3016.
- **Day-Ahead Unit Commitment for Reliability:** In 2013, 4.6 percent of the total day-ahead generation was scheduled as must run by PJM, of which 66.9 percent was made whole.
- **Lost Opportunity Cost Credits:** In 2013, lost opportunity cost credits decreased by $105.1 million compared to 2012. In 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 61.7 percent

1 This section has been renamed Energy Uplift rather than Operating Reserves. Energy uplift is a more accurate description of the topic than operating reserves, which may be confused with the concept of operating reserves for reliability as defined in FERC Order 888.

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.

of all lost opportunity cost credits, 55.0 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 60.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 57.0 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.

- **Lost Opportunity Cost Calculation:** In 2013, lost opportunity cost credits would have been reduced by an additional $22.8 million, or 26.3 percent, if all recommendations proposed by the MMU on this issue had been implemented.
- **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. The relevant 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 2013, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $86.4 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.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in 2013, the average rate paid by a DEC in the Eastern Region would have been $0.202 per MWh, which is 93.9 percent less ($3.099 per MWh) than the actual average rate paid.

2013 Energy Uplift Charges Increase

- **Unallocated Congestion Charges:** In 2013, congestion charges that could not be allocated to FTR holders accounted for a $19.2 million increase in energy uplift charges compared to 2012.
- **Unit Scheduling/Commitment and Allocation Change:** The need to schedule/commit resources as must run for black start and reactive support combined with the unit scheduling/commitment change performed by PJM in September 2012 and the energy uplift charges allocation change filed by PJM in December 2012 resulted in a net $21.1 million increase in energy uplift charges in 2013 compared to 2012. This issue had different impacts in each energy uplift category.
- **FMU Adders:** The impact of FMU adders included in the offers of units providing reactive support was $81.7 million. These units became eligible for FMU adders in 2013 after qualifying for the adder based on the percentage of run hours on which they were offer capped.
- **Reactive Credits Settlement Issue:** PJM announced a settlement issue due to an unintended logging error regarding units scheduled in the Day-Ahead Energy Market for reactive support. The estimated impact of this issue is $26.2 million. A portion or all of these payments might be resettled depending on the underlying reason for dispatching these units in real time.
- **Winter Days:** Energy uplift charges in the winter days of 2013 were $88.0 million more than the energy uplift charges in the winter days of 2012. This increase was primarily a result of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Recommendations

- The MMU recommends that PJM clearly identify, 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 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 also recommends other rule changes regarding the calculation of lost opportunity cost credits to units scheduled in the Day-Ahead Energy Market and not committed in real time:
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be eligible for an LOC compensation when committed or decommitted within an hour.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- 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 to avoid unintended consequences.
- 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 also 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 eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- 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 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 operation results in a lower loss or no loss at all.
- The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
- 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.

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 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.

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>.

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	in RTO, Eastern or Western Region
			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	Zonal Real-Time Load
			Reactive Services Local Constraint	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

Day-Ahead Operating Reserves

Day-ahead operating reserve credits consist of make whole payments to generators, import transactions and load response resources in the Day-Ahead Energy Market.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. In addition any unallocated congestion charges that could not be allocated to FTR holders are allocated as day-ahead operating reserve charges.

Balancing Operating Reserves

Balancing operating reserve credits consist of make whole and lost opportunity cost payments in the balancing market. Balancing operating reserve credits are paid to generators, import transactions and load response resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generators when their output is reduced or suspended at PJM's request for reliability purposes from their economic or self-scheduled output level or when combustion turbines or diesels are scheduled in the Day-Ahead Energy Market and not committed in real time. Balancing operating reserve credits are paid to real-time import transactions, if the real-time LMP at the import pricing point is less than the price specified in the transaction. Balancing operating reserve credits are also paid to resources when canceled before coming online.

The balancing operating reserve charges that result from paying the total balancing operating reserve credits are allocated daily to PJM members in different categories defined by the balancing operating reserve cost allocation rules (BORCA). The rules classify the charges as reliability and deviations. Balancing operating reserve credits paid to units that operate at a loss at the request of a third party are paid by the requesting party.[5]

Reactive Services

Reactive service credits are paid to units committed in real time for the purpose of maintaining the reactive reliability of the PJM region. Units are paid reactive services credits if such units are reduced or suspended at the request of PJM and the LMP at the unit's bus is higher than its offered price or if their output is increased at the request of PJM for the purpose of reactive services and the offered price is higher than the LMP at the unit's bus. Synchronous condensers may also receive reactive service credits by providing synchronous condensing for the purpose of maintaining reactive reliability at the request of PJM.

Reactive services credits are also paid in the form of day-ahead operating reserve credits to units scheduled in the Day-Ahead Energy Market to provide reactive services in real time. These credits consist of make whole payments to units scheduled in Day-Ahead Energy Market to maintain the reactive reliability in real time.[6]

The costs of units committed in real time and scheduled in Day-Ahead Energy Market to maintain the reactive reliability of the PJM region are allocated as reactive services charges. Reactive service charges are allocated daily to real-time load in the control zone or zones where the reactive service was provided.

Synchronous Condensing

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency operation or reactive services.[7]

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions.

Black Start Services

Black start services credits are paid in the form of day-ahead operating reserve credits or balancing operating reserve credits depending on whether the unit was scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service. These credits consist of make whole payments to units capable of providing black start services.[8]

The black start services charges that result from paying day-ahead and balancing operating reserve credits to units providing black start services or performing black start testing are allocated monthly to PJM members in proportion to their zone/non-zone peak transmission use and point to point transmission reservations.[9]

5 Balancing operating reserve charges and credits to units requested by a third party are categorized as balancing local constraint charges and credits in this report.

6 Day-ahead operating reserve credits paid to units scheduled to provide reactive services are categorized as day-ahead reactive services credits in this report.

7 See "Section 5.2.3 Credits for Synchronous Condensing," of "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013).

8 Day-ahead and balancing operating reserve credits paid to units providing black start services or performing black start testing are categorized as day-ahead or balancing black start services credits in this report.

9 See OATT. Schedule 6A for the definition of zone and non-zone peak transmission use.

Balancing Operating Reserve Cost Allocation

Table 4-3 Balancing operating reserve cost allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market**: LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:**Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 4-3 shows the process for identifying balancing operating reserves credits as related either to reliability or deviations. Such credits are assigned to units during two periods, the reliability analysis (performed after the Day-Ahead Energy Market is cleared) and the Real-Time Energy Market.

During PJM's reliability analysis, performed after the Day-Ahead Energy Market is cleared, credits are allocated for conservative operations or to meet forecasted real-time load. Conservative operations mean that units are committed due to conditions that warrant noneconomic actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are also committed to operate to meet the forecasted real-time load plus any operating reserve requirements in addition to the physical units committed in the Day-Ahead Energy Market. The resultant credits are defined as deviation credits.

In the Real-Time Energy Market, credits are also identified as related to either reliability or deviations. Credits are paid to units that are committed by PJM for reliability purposes if the LMP at the unit's bus is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as reliability credits and are allocated to real-time load plus exports.

Credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations.

Reliability and deviations credits are categorized by region based on whether a unit was committed for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500 kV or 765 kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

Determinants and Deviation Categories

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of control zones, hubs/aggregates and interfaces. Table 4-4 shows the composition of the Eastern and Western balancing operating reserve regions.

Table 4-4 Balancing operating reserve regions[10]

Location Type	Eastern Region	Western Region
Control Zones	AECO	AEP
	BGE	AP
	Dominion	ATSI
	DPL	ComEd
	JCPL	DAY
	Met-Ed	DEOK
	PECO	DLCO
	PENELEC	EKPC
	Pepco	
	PPL	
	PSEG	
	RECO	
Hubs / Aggregates	Eastern	AEP - Dayton
	New Jersey	ATSI Generators
	Western	Ohio
Interfaces	CLPE Exp	IMO
	CPLE Imp	MISO
	Duke Exp	NIPSCO
	Duke Imp	Northwest
	Hudson	OVEC
	Linden	
	NCMPA Exp	
	NCMPA Imp	
	Neptune	
	NYIS	
	South Exp	
	South Imp	

Credits paid to generators defined to be operating for reliability purposes are charged to real-time load and exports, credits paid to generators and import transactions defined to be operating to control deviations on the system, paid for energy lost opportunity credits and paid to resources canceled before coming online are charged to deviations. Table 4-5 shows the different types of deviations.

Table 4-5 Operating reserve deviations

	Deviations	
Day-Ahead		Real-Time
Day-Ahead Demand Bid	Demand (Withdrawal)	Real-Time Load
Day-Ahead Bilateral Sales	(RTO, East, West)	Real-Time Bilateral Sales
Day-Ahead Export Transactions		Real-Time Export Transactions
Decrement Bids		
Day-Ahead Bilateral Purchases	Supply (Injection)	Real-Time Bilateral Purchases
Day-Ahead Import Transactions	(RTO, East, West)	Real-Time Import Transactions
Increment Offers		
Day-Ahead Scheduled Generation	Generator (Unit)	Real-Time Generation

Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by control zone, hub/aggregate, or interface. Each hourly deviation absolute value is totaled for the day for daily deviation. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared day-ahead load plus day-ahead exports plus day-ahead bilateral sale transactions; and b) the sum of real-time load plus real-time bilateral sale transactions plus real-time exports.
- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports plus day-ahead bilateral purchase transactions; and b) the sum of the real-time bilateral purchase transactions plus real-time imports.
- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted. A deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

10 Only two hubs include buses in both the Eastern and Western regions: the Dominion Hub and the Western Interface Hub.

Demand and supply deviations are netted by control zone, hub/aggregate, or interface. For example, a negative deviation at a bus can be offset by a positive deviation at another bus in the same control zone.

The sum of each organization's netted deviations by control zone, hub/aggregate, or interface is assigned to either the Eastern or Western Region, depending on the location of the control zone, hub/aggregate, or interface. The RTO Region deviations are the sum of an organization's Eastern and Western regions deviations, plus deviations that occurred at hubs/aggregates that include buses in both regions. Generating units that deviate from real-time dispatch may offset deviations by another generating unit at the same bus if that unit is electrically equivalent and owned by the same participant.

An organization's total daily balancing operating reserve charges based on deviations are the sum of the three deviation categories, by region (including the RTO), for the day, multiplied by each regional deviation rate plus lost opportunity cost and canceled resources rates.

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges increased by 35.6 percent in 2013 compared to 2012, to a total of $882.2 million. Table 4-6 shows total energy uplift charges from 1999 through 2013.[11]

Table 4-6 Total energy uplift charges: 1999 through 2013

	Total Energy Uplift Charges	Annual Change	Annual Percentage Change	Energy Uplift as a Percent of Total PJM Billing
1999	$133,897,428	NA	NA	7.5%
2000	$216,985,147	$83,087,719	62.1%	9.6%
2001	$284,046,709	$67,061,562	30.9%	8.5%
2002	$273,718,553	($10,328,156)	(3.6%)	5.8%
2003	$376,491,514	$102,772,961	37.5%	5.4%
2004	$537,587,821	$161,096,307	42.8%	6.1%
2005	$712,601,789	$175,013,968	32.6%	3.1%
2006	$365,572,034	($347,029,755)	(48.7%)	1.7%
2007	$503,279,869	$137,707,835	37.7%	1.6%
2008	$474,268,500	($29,011,369)	(5.8%)	1.4%
2009	$322,729,996	($151,538,504)	(32.0%)	1.2%
2010	$622,843,365	$300,113,369	93.0%	1.8%
2011	$605,017,353	($17,826,013)	(2.9%)	1.7%
2012	$650,777,886	$45,760,533	7.6%	2.2%
2013	$882,219,896	$231,442,009	35.6%	2.6%

11 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 January 20, 2014.

Total energy uplift charges increased by $231.4 million or 35.6 percent in 2013 compared to 2012. Table 4-7 compares energy uplift charges by category for 2012 and 2013. The increase of $231.4 million in 2013 is comprised of a decrease of $48.9 million in day-ahead operating reserve charges, a decrease of $61.6 million in balancing operating reserve charges, an increase of $263.5 million in reactive services charges, an increase of $0.2 million in synchronous condensing charges and an increase of $78.2 million in black start services charges. The change in total energy uplift charges was due to several factors that impacted all categories. These factors were unallocated congestion charges, reactive and black start unit scheduling/commitment change, energy uplift charges allocation change associated with units needed for black start and reactive support, improvement in combustion turbines commitment, colder winter weather, FMU adders and reactive services credits settlement issue.

Table 4-7 Energy uplift charges by category: 2012 and 2013

Category	2012	2013	Change	Percentage Change
Day-Ahead Operating Reserves	$134,445,132	$85,588,105	($48,857,027)	(36.3%)
Balancing Operating Reserves	$431,789,677	$370,159,625	($61,630,052)	(14.3%)
Reactive Services	$76,010,175	$339,482,039	$263,471,864	346.6%
Synchronous Condensing	$148,250	$396,377	$248,127	167.4%
Black Start Services	$8,384,651	$86,593,749	$78,209,098	932.8%
Total	$650,777,886	$882,219,896	$231,442,009	35.6%

Table 4-8 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges attributable to unallocated congestion charges.[12,13,14] Day-ahead operating reserve charges decreased 36.3 percent or $48.9 million in 2013 compared to 2012. Day-ahead operating reserve charges (excluding unallocated congestion charges) decreased by $68.1 million in 2013 compared to 2012. This decrease was mainly due to the December 1, 2012, allocation change for day-ahead operating reserve

12 Attributable means that these charges are the result of credits paid to the identified resources.

13 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, of which 74.6 percent was charged in 2013.

14 See Section 13, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

charges associated with units scheduled in the Day-Ahead Energy Market to provide black start and reactive support. These units started to be scheduled in the Day-Ahead Energy Market in September 2012. Between September and November 2012, day-ahead operating reserve credits to units providing black start and reactive support were allocated as day-ahead operating reserve charges. Between September and November 2013, day-ahead operating reserve charges decreased by $58.3 million when compared to the same three month period of 2012. The change in the remaining nine months was a decrease of $9.8 million. Unallocated congestion charges increased by $19.2 in 2013 compared to 2012. Day-ahead operating reserve charges are paid by day-ahead demand, day-ahead exports and decrement bids.

Table 4-8 Day-ahead operating reserve charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Day-Ahead Operating Reserve Charges	$133,614,503	$65,116,984	($68,497,518)	99.4%	76.1%
Day-Ahead Operating Reserve Charges for Load Response	$107	$442,597	$442,490	0.0%	0.5%
Unallocated Congestion Charges	$830,522	$20,028,523	$19,198,001	0.6%	23.4%
Total	$134,445,132	$85,588,105	($48,857,027)	100.0%	100.0%

Table 4-9 Balancing operating reserve charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Balancing Operating Reserve Reliability Charges	$75,763,342	$53,475,908	($22,287,434)	17.5%	14.4%
Balancing Operating Reserve Deviation Charges	$348,174,780	$316,054,920	($32,119,860)	80.6%	85.4%
Balancing Operating Reserve Charges for Load Response	$236,202	$552,379	$316,177	0.1%	0.1%
Balancing Local Constraint Charges	$7,615,353	$76,419	($7,538,934)	1.8%	0.0%
Total	$431,789,677	$370,159,625	($61,630,052)	100.0%	100.0%

Table 4-9 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $61.6 million in 2013 compared to 2012. This decrease was mainly a result of the change in allocation of energy uplift credits to units providing black start support. These units started to be scheduled in the Day-Ahead Energy Market in September 2012. Before September 2012, these units were committed in real time and any associated energy uplift charges were allocated as balancing operating reserve charges for reliability in the Western Region. West reliability charges decreased by $46.3 million in 2013 compared to 2012. Another factor that contributed to the decrease of balancing operating reserve charges was lower lost opportunity cost (LOC) credits. In 2013, LOC and canceled resources related charges decreased by $108.2 million compared to 2012. This occurred in part because PJM began scheduling units in the Day-Ahead Energy Market for black start and reactive support and PJM's implementation of the combustion turbine optimizer tool (CTO).[15] In spite of these reductions in balancing operating reserve charges, the cold weather of 2013 compared to 2012 had an increasing effect on total balancing operating reserve charges. In the 2013 winter days, balancing operating reserve charges (excluding west reliability charges, LOC and canceled resources related charges) increased by $88.0 compared to the 2012 winter days. This increase was mainly a result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. Balancing local constraint charges decreased by $7.5 million in 2013 compared to 2012, these charges are directly allocated to the third-party that requested the operation of a unit or units to provide relief to constraints not under PJM's responsibility.

Table 4-10 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In 2013, 72.5 percent of

15 See "Commitment Decision Making," PJM Presentation to the Energy Market Uplift Senior Task Force (August 20, 2013) for more detail on the combustion turbine optimizer tool. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130820/20130820-bor-commitment-education.ashx>.

all balancing operating reserve deviation charges were attributable to make whole payments to generators and import transactions, an increase of 28.5 percentage points compared to the share in 2012. The increase was primarily due to higher deviation credits to generators in central and northeastern New Jersey during the 2013 winter days and lower balancing operating reserve deviation charges attributable to energy lost opportunity cost and canceled resources.

Table 4-10 Balancing operating reserve deviation charges: 2012 and 2013

Charge Attributable To	2012	2013	Change	2012 Share	2013 Share
Make Whole Payments to Generators and Imports	$152,983,924	$229,063,509	$76,079,585	43.9%	72.5%
Energy Lost Opportunity Cost	$191,756,987	$86,635,563	($105,121,424)	55.1%	27.4%
Canceled Resources	$3,433,870	$355,849	($3,078,021)	1.0%	0.1%
Total	$348,174,780	$316,054,920	($32,119,860)	100.0%	100.0%

RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2013, regional balancing operating reserve charges decreased by $54.4 million compared to 2012. Balancing operating reserve reliability charges decreased by $22.3 million or 29.4 percent and balancing operating reserve deviation charges decreased by $32.1 million or 9.2 percent. Total balancing operating reserve deviation charges decreased in 2013 compared to 2012, but in 2013,

Table 4-11 Additional energy uplift charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Reactive Services Charges	$76,010,175	$339,482,039	$263,471,864	89.9%	79.6%
Synchronous Condensing Charges	$148,250	$396,377	$248,127	0.2%	0.1%
Black Start Services Charges	$8,384,651	$86,593,749	$78,209,098	9.9%	20.3%
Total	$84,543,077	$426,472,166	$341,929,089	100.0%	100.0%

Table 4-12 Regional balancing charges allocation: 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18,820,641	4.4%	$8,015,395	1.9%	$46,269,752	10.9%	$73,105,788	17.2%
	Real-Time Exports	$594,759	0.1%	$169,794	0.0%	$1,893,001	0.4%	$2,657,554	0.6%
	Total	$19,415,400	4.6%	$8,185,189	1.9%	$48,162,753	11.4%	$75,763,342	17.9%
Deviation Charges	Demand	$186,403,740	44.0%	$16,506,118	3.9%	$4,777,995	1.1%	$207,687,853	49.0%
	Supply	$56,154,963	13.2%	$4,579,688	1.1%	$1,263,970	0.3%	$61,998,621	14.6%
	Generator	$71,003,792	16.7%	$5,263,176	1.2%	$2,221,339	0.5%	$78,488,306	18.5%
	Total	$313,562,495	74.0%	$26,348,982	6.2%	$8,263,304	1.9%	$348,174,780	82.1%
Total Regional Balancing Charges		$332,977,895	78.5%	$34,534,171	8.1%	$56,426,056	13.3%	$423,938,122	100%

Table 4-11 shows reactive services, synchronous condensing and black start services charges. Black start services charges were introduced in December 2012. Reactive services charges increased by $263.5 million in 2013 compared to 2012. This increase was mainly a result of the unit scheduling/commitment change for reactive support, the impact of FMU adders and a dispatch logging issue that impacted the reactive services charges settlement in the second half of 2013.

Table 4-12 and Table 4-13 show the amount and percentages of regional balancing charges allocation for 2012 and 2013. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the

deviation charges in the Eastern Region increased by $89.6 million compared to 2012, as a result of payments to units providing relief to transmission constraints in north/central New Jersey and units providing support to the Con Edison – PSEG wheeling contracts.[16,17] The remaining two deviation categories decreased by $121.8 million.

16 See "Selected MMU Market Issues," MMU Presentation to the Members Committee (February 25, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mc/20130225-webinar/20130225-item-08-imm-flowchart.ashx>.

17 See "Winter 2012-2013: Balancing Operating Reserve Rates," PJM Presentation at the Market Implementation Committee (March 6, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-10-winter-2012-2013-bor-rates.ashx>.

Table 4-13 Regional balancing charges allocation: 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$39,446,593	10.7%	$10,903,811	3.0%	$1,782,049	0.5%	$52,132,453	14.1%
	Real-Time Exports	$989,139	0.3%	$309,122	0.1%	$45,195	0.0%	$1,343,455	0.4%
	Total	$40,435,731	10.9%	$11,212,932	3.0%	$1,827,244	0.5%	$53,475,908	14.5%
Deviation Charges	Demand	$115,143,323	31.2%	$72,417,440	19.6%	$3,904,232	1.1%	$191,464,995	51.8%
	Supply	$31,112,602	8.4%	$19,274,386	5.2%	$1,094,445	0.3%	$51,481,434	13.9%
	Generator	$46,765,077	12.7%	$24,298,419	6.6%	$2,044,995	0.6%	$73,108,491	19.8%
	Total	$193,021,002	52.2%	$115,990,246	31.4%	$7,043,673	1.9%	$316,054,920	85.5%
Total Regional Balancing Charges		$233,456,733	63.2%	$127,203,178	34.4%	$8,870,917	2.4%	$369,530,828	100%

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.[18]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2012 and 2013. The average rate in 2013 was $0.079 per MWh, $0.082 per MWh lower than the average in 2012. The highest rate occurred on July 16, when the rate reached $0.646 per MWh, 41.3 percent lower than the $1.100 per MWh reached in 2012, on October 30. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. The average rate in 2013, including unallocated congestion charges, was $0.103 per MWh, 30.8 percent higher than the day-ahead operating reserve rate without unallocated congestion charges.

The increase in the day-ahead operating reserve rate on July 16 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 25 percent of their scheduled run time. On July 16, 86 units received day-ahead operating reserve credits, 46 were noneconomic for their entire scheduled run time and four were economic for 25 percent or less of their scheduled run time. That was the highest number of units scheduled noneconomic in the Day-Ahead Energy Market in 2013. On July 16, 43 units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; 32 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.[19] The day-ahead operating reserve rate for July 16 would have been $0.148 per MWh or 22.9 percent lower if the offset had been credited. Similar circumstances occurred on July 17, 18, 19 and September 11.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2012 and 2013[20]

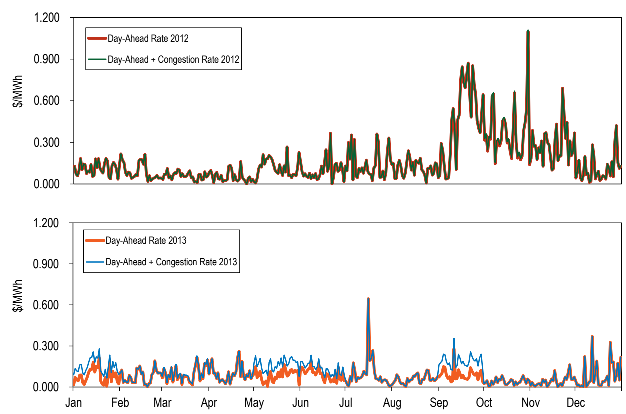


Figure 4-2 shows the RTO and the regional reliability rates for 2012 and 2013. The average daily RTO reliability rate was $0.051 per MWh. The highest RTO reliability rate in 2013 occurred on January 23, when the rate reached $0.802 per MWh. The average daily Eastern Region reliability rate was $0.030 per MWh. The highest Eastern Region reliability rate in 2013 occurred on January 24, when the rate reached $2.887 per MWh.

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

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

20 On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation of certain operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market. 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.

The spikes in both rates were the result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. The transmission constraints were the result of issues with the 500 kV system which resulted in overloads on the 230 kV system. The issues on the 500 kV system were a combination of unplanned outages and unforeseen outages resulting from damage due to Hurricane Sandy. Cold weather in the region resulted in an increase in the Transco Zone 6 NY natural gas price index in January and February 2013 compared to previous months and compared to January and February 2012. The units committed to provide relief for the transmission constraints only set the LMP during short periods of time in comparison to their minimum run times, which increased the costs of operating reserves during periods when the units continue operating out of merit as a result of their operating parameters.[21]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2012 and 2013

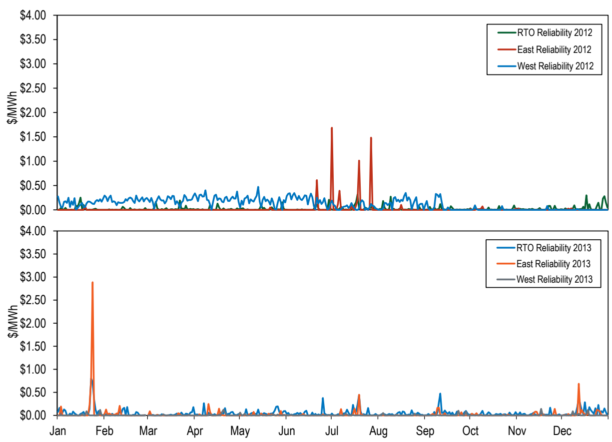


Figure 4-3 shows the RTO and regional deviation rates for 2012 and 2013. The average daily RTO deviation rate was $0.863 per MWh. The highest daily rate in 2013 occurred on January 23, when the RTO deviation rate reached $10.172 per MWh. Between January 1 and February 21, 2013, the Eastern Region deviation rate averaged $8.982 per MWh, reaching its highest rate on February 9, when it reached $32.876 per MWh. Prior to the 2012 – 2013 winter, the highest daily eastern region deviation rate since the creation of this rate on December 2008 occurred on December 18, 2012 when it reached $5.735 per MWh. The spikes in the eastern deviation rate in early January and from mid-January until the end of February were caused by the same issues that caused the RTO and eastern reliability rates to spike on January 25, a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Current balancing operating reserve rules allocate the costs of operating reserves in real time for reliability or deviations according to when the units are committed (before or during the operating day) and the number of intervals the units were operating noneconomic (more or less than four intervals). The spike in the RTO deviation rate on September 11 was mainly a result of the commitment in real time of combustion turbines that did not clear the Day-Ahead Energy Market and did not recover their total offer through energy and ancillary services revenues. This commitment was triggered by the issuance of a maximum generation action on that day.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2012 and 2013

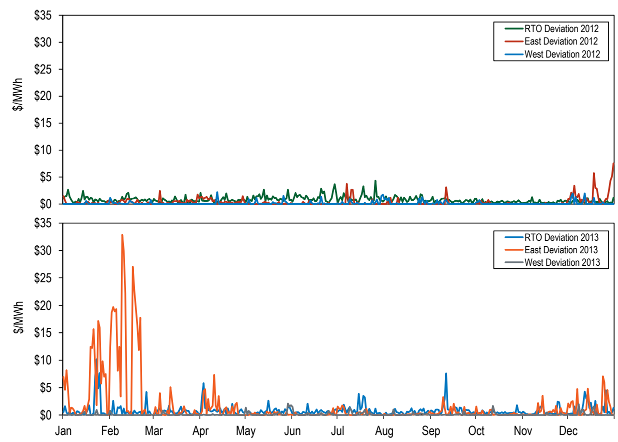


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2012 and 2013. The lost opportunity rate averaged $0.705 per MWh. The highest lost opportunity cost rate occurred on September 11, when it reached $8.509 per MWh.

The LOC rate has shown smaller spikes in 2013 compared to 2012. In 2013, the top 10 daily LOC rates averaged $4.837 per MWh, $3.482 per MWh less than the average of the top 10 daily LOC rates in 2012. The top LOC rates in 2013 occurred between July 16 and

21 The relevant parameters are minimum run time, minimum down time, maximum daily starts and maximum weekly starts.

July 18 and between September 10 and 11. The main reasons for these high rates continue to be combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not committed in real time. Another reason was the need to reduce the output of steam units due to transmission line limits. On September 11, the manual dispatch of a small number of units in the ATSI Control Zone was responsible for 54.0 percent of the LOC rate on that day, the units were manually dispatched down because of a constraint within ATSI during hours when the ATSI interface was binding and demand resources were setting ATSI prices at $1,800 per MWh.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2012 and 2013

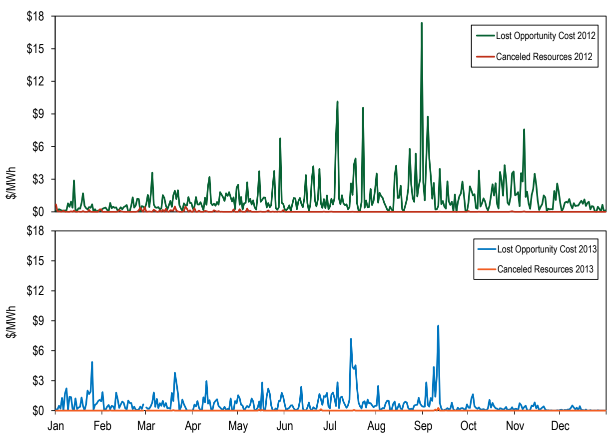


Table 4-14 shows the average rates for each region in each category for 2012 and 2013.

Table 4-14 Operating reserve rates ($/MWh): 2012 and 2013

Rate	2012 ($/MWh)	2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.161	0.079	(0.082)	(51.1%)
Day-Ahead with Unallocated Congestion	0.162	0.103	(0.059)	(36.5%)
RTO Reliability	0.025	0.051	0.026	107.2%
East Reliability	0.022	0.030	0.008	35.9%
West Reliability	0.115	0.004	(0.111)	(96.2%)
RTO Deviation	0.820	0.863	0.043	5.2%
East Deviation	0.333	1.868	1.535	460.8%
West Deviation	0.127	0.122	(0.006)	(4.6%)
Lost Opportunity Cost	1.329	0.705	(0.623)	(46.9%)
Canceled Resources	0.024	0.003	(0.021)	(87.8%)

Table 4-15 shows the operating reserve cost of a one MW transaction during 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $3.301 per MWh with a maximum rate of $33.056 per MWh, a minimum rate of $0.147 per MWh and a standard deviation of $5.029 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-15 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 4-15 Operating reserve rates statistics ($/MWh): 2013

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	33.024	3.198	0.024	5.028
	DEC	33.056	3.301	0.147	5.029
	DA Load	0.646	0.103	0.000	0.076
	RT Load	3.610	0.073	0.000	0.226
	Deviation	33.024	3.198	0.024	5.028
West	INC	16.429	1.561	0.024	1.804
	DEC	16.785	1.664	0.116	1.825
	DA Load	0.646	0.103	0.000	0.076
	RT Load	0.802	0.053	0.000	0.087
	Deviation	16.429	1.561	0.024	1.804

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. Even though reactive services rates are not published, a local voltage support rate for each control zone can be calculated, also a reactive transfer interface support rate can calculated for the entire RTO.

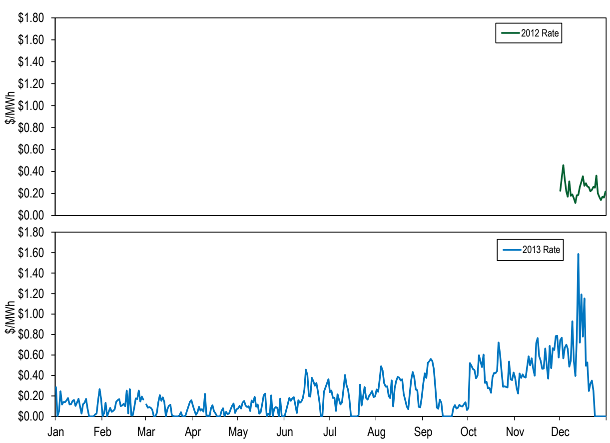
Table 4-16 shows the reactive services rates associated with local voltage support 2012 and 2013. Table 4-16 shows that in 2013 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $2.538 per MWh for reactive services associated with local voltage support, $1.568 or 161.8 percent higher than the average rate paid in 2012.

Table 4-16 Local voltage support rates: 2012 and 2013

Control Zone	2012 ($/MWh)	2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.132	0.227	0.095	71.6%
AEP	0.005	0.057	0.051	943.2%
AP	0.002	0.002	(0.001)	(24.1%)
ATSI	0.219	0.690	0.472	215.4%
BGE	0.174	0.305	0.130	74.6%
ComEd	0.001	0.001	0.000	58.0%
DAY	0.003	0.000	(0.003)	(100.0%)
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.001	0.000	(0.001)	(100.0%)
Dominion	0.015	0.022	0.007	48.8%
DPL	0.969	2.538	1.568	161.8%
EKPC	NA	0.006	NA	NA
JCPL	0.199	0.346	0.147	73.7%
Met-Ed	0.092	0.021	(0.071)	(77.3%)
PECO	0.099	0.030	(0.068)	(69.4%)
PENELEC	0.508	1.900	1.392	274.2%
Pepco	0.145	0.011	(0.134)	(92.3%)
PPL	0.154	0.016	(0.138)	(89.6%)
PSEG	0.211	0.183	(0.029)	(13.6%)
RECO	0.084	0.001	(0.083)	(98.3%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2012 and 2013. PJM began allocating these operating reserve charges to reactive services on December 1, 2012. This rate is charged to real-time load in the entire RTO. The average rate in 2013 was $0.224 per MWh. The increase in this reactive rate in the second half of 2013 has been in part a result of the inclusion of FMU adders in the cost-based offers of some of the units routinely used for this service. These units are eligible for FMU adders because they are being offer capped.[22]

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2012 and 2013



22 See OATT Attachment K - Appendix § 6.4.

Balancing Operating Reserve Determinants

Table 4-17 shows the determinants used to allocate the regional balancing operating reserve charges for 2012 and 2013. Total real-time load and real-time exports were 3,943,503 MWh or 0.5 percent higher in 2013 compared to 2012. Total deviations summed across the demand, supply, and generator categories were 21,482,468 MWh or 14.9 percent lower in 2013 compared to 2012.

Table 4-17 Balancing operating reserve determinants (MWh): 2012 and 2013

		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
2012	RTO	764,248,367	26,601,926	790,850,293	85,045,749	26,275,474	32,986,724	144,307,947
	East	362,985,584	10,425,635	373,411,219	48,968,172	14,730,071	15,390,340	79,088,583
	West	401,262,783	16,176,291	417,439,074	35,792,061	11,477,683	17,596,384	64,866,127
2013	RTO	773,789,714	21,004,083	794,793,797	72,881,402	19,570,481	30,373,596	122,825,478
	East	366,566,019	9,763,023	376,329,041	38,926,826	9,797,593	13,357,715	62,082,133
	West	407,223,695	11,241,060	418,464,755	31,767,799	9,188,787	17,015,882	57,972,467
Difference	RTO	9,541,347	(5,597,843)	3,943,503	(12,164,347)	(6,704,993)	(2,613,128)	(21,482,468)
	East	3,580,434	(662,612)	2,917,822	(10,041,346)	(4,932,479)	(2,032,625)	(17,006,450)
	West	5,960,912	(4,935,231)	1,025,681	(4,024,262)	(2,288,896)	(580,502)	(6,893,660)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-18 shows the different categories by the type of transactions that incur deviations. In 2013, 19.5 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 80.5 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 4-18 Deviations by transaction type: 2013

Deviation Category		Deviation (MWh)			Share		
	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	1,015,262	502,953	512,309	0.8%	0.8%	0.9%
	DECs Only	7,743,083	3,032,612	2,523,694	6.3%	4.9%	4.4%
	Exports Only	5,505,601	3,115,186	2,390,415	4.5%	5.0%	4.1%
	Load Only	47,522,671	27,807,763	19,714,908	38.7%	44.8%	34.0%
	Combination with DECs	5,729,451	3,094,113	2,635,338	4.7%	5.0%	4.5%
	Combination without DECs	5,365,333	1,374,199	3,991,135	4.4%	2.2%	6.9%
Supply	Bilateral Purchases Only	1,297,947	828,666	469,281	1.1%	1.3%	0.8%
	Imports Only	7,708,563	4,011,345	3,697,218	6.3%	6.5%	6.4%
	INCs Only	5,900,154	1,837,538	3,478,515	4.8%	3.0%	6.0%
	Combination with INCs	4,579,475	3,045,942	1,533,534	3.7%	4.9%	2.6%
	Combination without INCs	84,342	74,103	10,239	0.1%	0.1%	0.0%
Generators		30,373,596	13,357,715	17,015,882	24.7%	21.5%	29.4%
Total		122,825,478	62,082,133	57,972,467	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-19 shows the totals for each credit category for 2012 and 2013. During 2013, 42.9 percent of total energy uplift credits were in the balancing operating reserve category. This percentage decreased 23.5 percentage points from 66.4 percent in. This decrease was in part due to the reallocation of energy uplift credits paid to units providing black start services and reactive services. In 2013, the percent of total energy uplift credits in the reactive services category increased to 39.4 percent, 27.7 percentage points higher than 2012.

Table 4-19 Energy uplift credits by category: 2012 and 2013

Category	Type	2012	2013	Change	Percentage Change	2012 Share	2013 Share
Day-Ahead	Generators	$133,613,948	$65,116,975	($68,496,972)	(51.3%)	20.6%	7.6%
	Imports	$554	$9	($545)	(98.3%)	0.0%	0.0%
	Load Response	$108	$442,597	$442,490	411,077.8%	0.0%	0.1%
Balancing	Canceled Resources	$3,433,872	$355,849	($3,078,023)	(89.6%)	0.5%	0.0%
	Generators	$228,590,056	$282,494,308	$53,904,252	23.6%	35.2%	32.8%
	Imports	$159,564	$45,112	($114,452)	(71.7%)	0.0%	0.0%
	Load Response	$236,077	$552,212	$316,135	133.9%	0.0%	0.1%
	Local Constraints Control	$7,615,353	$76,419	($7,538,934)	(99.0%)	1.2%	0.0%
	Lost Opportunity Cost	$191,756,979	$86,635,564	($105,121,415)	(54.8%)	29.5%	10.0%
Reactive Services	Day-Ahead	$24,234,095	$290,687,063	$266,452,968	1,099.5%	3.7%	33.7%
	Local Constraints Control	$37,266	$106,287	$69,022	185.2%	0.0%	0.0%
	Lost Opportunity Cost	$2,458,300	$5,130,166	$2,671,866	108.7%	0.4%	0.6%
	Reactive Services	$49,134,480	$43,171,412	($5,963,068)	(12.1%)	7.6%	5.0%
	Synchronous Condensing	$146,035	$387,111	$241,076	165.1%	0.0%	0.0%
Synchronous Condensing		$148,250	$396,377	$248,127	167.4%	0.0%	0.0%
Black Start Services	Day-Ahead	$8,204,976	$84,121,142	$75,916,167	925.2%	1.3%	9.8%
	Balancing	$190,568	$2,277,634	$2,087,066	1,095.2%	0.0%	0.3%
	Testing	$0	$363,916	$363,916	NA	0.0%	0.0%
Total		$649,960,482	$862,360,155	$212,399,674	32.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-20 shows the distribution of total energy uplift credits by unit type for 2012 and 2013. Credits paid to combined cycle units increased 142.7 percent or $113.0 million, mainly due to units providing relief for transmission constraints and supporting the Con Edison – PSEG wheeling contracts during days with high natural gas prices. In 2013, 22.3 percent of all operating reserve credits paid to units were paid to combined cycle units, 10.1 percentage points more than the share in 2012.

Table 4-20 Energy uplift credits by unit type: 2012 and 2013

Unit Type	2012	2013	Change	Percentage Change	2012 Share	2013 Share
Combined Cycle	$79,199,434	$192,201,505	$113,002,071	142.7%	12.2%	22.3%
Combustion Turbine	$226,859,986	$149,523,385	($77,336,601)	(34.1%)	34.9%	17.4%
Diesel	$3,728,045	$6,525,487	$2,797,442	75.0%	0.6%	0.8%
Hydro	$294,991	$555,413	$260,422	88.3%	0.0%	0.1%
Nuclear	$1,655,968	$136,961	($1,519,006)	(91.7%)	0.3%	0.0%
Steam - Coal	$284,453,370	$458,937,387	$174,484,017	61.3%	43.8%	53.3%
Steam - Other	$44,681,160	$42,891,533	($1,789,626)	(4.0%)	6.9%	5.0%
Wind	$8,691,224	$10,548,551	$1,857,327	21.4%	1.3%	1.2%
Total	$649,564,178	$861,320,224	$211,756,046	32.6%	100.0%	100.0%

Table 4-21 shows the distribution of energy uplift credits by category and by unit type in 2013. Combined cycle units received 48.8 percent of the day-ahead generator credits in 2013, 32.4 percentage points higher than the share received in 2012. Combined cycle units received 49.1 percent of the balancing generator credits in 2013, 31.1 percentage points higher than the share received in 2012. Combustion turbines and diesels received 72.7 percent of the lost opportunity cost credits in 2013, 14.0 percentage points lower than the share received in 2012.

Table 4-21 Energy uplift credits by unit type: 2013

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	48.8%	49.1%	0.0%	13.5%	7.1%	4.6%	0.0%	0.0%
Combustion Turbine	10.7%	24.0%	8.8%	59.5%	72.5%	3.2%	100.0%	0.4%
Diesel	0.1%	0.4%	0.0%	16.0%	0.1%	1.6%	0.0%	0.0%
Hydro	0.3%	0.0%	62.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Steam - Coal	35.9%	16.5%	9.1%	10.0%	7.7%	87.1%	0.0%	99.6%
Steam - Others	4.3%	10.0%	19.8%	0.0%	0.2%	3.4%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	1.0%	12.1%	0.0%	0.0%	0.0%
Total	$65,116,975	$282,494,308	$355,849	$76,419	$86,635,563	$339,482,040	$396,377	$86,762,692

Table 4-21 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In 2013, coal units received 87.1 percent of all reactive services credits, 11.9 percentage points higher than the share received in 2012. Synchronous condensing was only provided by combustion turbines. Coal units received 99.6 percent of all black start services credits.

Economic and Noneconomic Generation[23]

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 4-22 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating 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 2013, 32.6 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 31.5 percent of the real-time generation was eligible for balancing operating reserve credits.[24]

Table 4-22 Day-ahead and real-time generation (GWh): 2013

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	809,695	263,755	32.6%
Real-Time	797,100	250,907	31.5%

Table 4-23 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In 2013, 81.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 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 4-23 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

23 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.

24 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.

Table 4-23 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2013

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	215,263	48,492	81.6%	18.4%
Real-Time	167,363	83,544	66.7%	33.3%

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 4-24 shows the generation receiving day-ahead and balancing operating reserve credits. In 2013, 13.2 percent of the day-ahead generation eligible for operating reserve credits received credits and 8.3 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-24 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2013

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	263,755	34,805	13.2%
Real-Time	250,907	20,732	8.3%

Geography of Charges and Credits

Table 4-25 shows the geography of charges and credits in 2013. Table 4-25 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 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 1.4 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 6.5 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 37.4 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had an 85.1 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-25 also shows that 82.2 percent of all charges were allocated in control zones, 5.9 percent in hubs and aggregates and 11.9 percent in interfaces.

Table 4-25 Geography of regional charges and credits: 2013[25]

Location		Charges	Credits	Balance	Shares Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$6,236,329	$4,015,220	($2,221,109)	1.4%	0.9%	1.4%	0.0%
	AEP - EKPC	$41,489,378	$29,746,951	($11,742,427)	9.5%	6.8%	7.4%	0.0%
	AP - DLCO	$23,274,970	$17,055,594	($6,219,376)	5.4%	3.9%	3.9%	0.0%
	ATSI	$19,723,093	$20,575,022	$851,929	4.5%	4.7%	0.0%	0.5%
	BGE - Pepco	$39,873,096	$41,149,212	$1,276,116	9.2%	9.5%	0.0%	0.8%
	ComEd - External	$34,984,178	$22,708,351	($12,275,827)	8.0%	5.2%	7.8%	0.0%
	DAY - DEOK	$15,367,451	$2,403,483	($12,963,968)	3.5%	0.6%	8.2%	0.0%
	Dominion	$40,129,662	$48,809,888	$8,680,226	9.2%	11.2%	0.0%	5.5%
	DPL	$12,138,887	$16,876,401	$4,737,514	2.8%	3.9%	0.0%	3.0%
	JCPL	$13,687,678	$17,285,344	$3,597,665	3.1%	4.0%	0.0%	2.3%
	Met-Ed	$10,284,379	$5,619,746	($4,664,633)	2.4%	1.3%	3.0%	0.0%
	PECO	$25,019,877	$7,049,433	($17,970,445)	5.8%	1.6%	11.4%	0.0%
	PENELEC	$17,666,232	$6,609,420	($11,056,812)	4.1%	1.5%	7.0%	0.0%
	PPL	$27,762,768	$32,091,195	$4,328,427	6.4%	7.4%	0.0%	2.7%
	PSEG	$28,409,227	$162,607,436	$134,198,208	6.5%	37.4%	0.0%	85.1%
	RECO	$1,079,633	$0	($1,079,633)	0.2%	0.0%	0.7%	0.0%
	All Zones	$357,126,839	$434,602,696	$77,475,857	82.2%	100.0%	50.9%	100.0%
Hubs and Aggregates	AEP - Dayton	$2,367,043	$0	($2,367,043)	0.5%	0.0%	1.5%	0.0%
	Dominion	$3,020,526	$0	($3,020,526)	0.7%	0.0%	1.9%	0.0%
	Eastern	$349,106	$0	($349,106)	0.1%	0.0%	0.2%	0.0%
	New Jersey	$918,228	$0	($918,228)	0.2%	0.0%	0.6%	0.0%
	Ohio	$112,200	$0	($112,200)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$1,459,083	$0	($1,459,083)	0.3%	0.0%	0.9%	0.0%
	Western	$17,421,845	$0	($17,421,845)	4.0%	0.0%	11.0%	0.0%
	RTEP B0328 Source	$189	$0	($189)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$25,648,219	$0	($25,648,219)	5.9%	0.0%	16.3%	0.0%
Interfaces	CPLE Imp	$0	$0	$0	0.0%	0.0%	0.0%	0.0%
	Hudson	$483,810	$0	($483,810)	0.1%	0.0%	0.3%	0.0%
	IMO	$5,954,434	$0	($5,954,434)	1.4%	0.0%	3.8%	0.0%
	Linden	$1,873,295	$0	($1,873,295)	0.4%	0.0%	1.2%	0.0%
	MISO	$6,895,321	$0	($6,895,321)	1.6%	0.0%	4.4%	0.0%
	Neptune	$1,084,662	$0	($1,084,662)	0.2%	0.0%	0.7%	0.0%
	NIPSCO	$34,330	$0	($34,330)	0.0%	0.0%	0.0%	0.0%
	Northwest	$189,945	$0	($189,945)	0.0%	0.0%	0.1%	0.0%
	NYIS	$8,845,643	$0	($8,845,643)	2.0%	0.0%	5.6%	0.0%
	OVEC	$1,520,343	$0	($1,520,343)	0.3%	0.0%	1.0%	0.0%
	South Exp	$6,231,249	$0	($6,231,249)	1.4%	0.0%	4.0%	0.0%
	South Imp	$18,759,729	$0	($18,759,729)	4.3%	0.0%	11.9%	0.0%
	All Interfaces	$51,872,760	$45,122	($51,827,639)	11.9%	0.0%	32.9%	0.0%
	Total	$434,647,818	$434,647,818	$0	100.0%	100.0%	100.0%	100.0%

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 4-26 shows the geography of reactive services charges. In 2013, 46.2 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 2.7 percent were paid by real-time load in multiple zones and 51.1 percent were paid by real-time load across the entire RTO. In 2013, resources in two control zones accounted for 99.8 percent of all reactive services costs allocated across the entire RTO.

Table 4-26 Geography of reactive services charges: 2013[26]

Location	Charges	Share of Charges
Single Zone	$156,669,607	46.2%
Multiple Zones	$9,203,271	2.7%
Entire RTO	$173,502,875	51.1%
Total	$339,375,753	100.0%

In 2013, the top three zones accounted for 68.3 percent of all the reactive services charges allocated to single zones.

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone

25 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-25 does not include synchronous condensing, local constraint control, black start services and reactive services charges and credits since these are allocated zonally.

26 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 09 (July 22, 2010).

accounted for 99.6 percent of all the black start services costs in 2013. 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 six control zones accounted for all synchronous condensing costs in 2013.

Energy Uplift Issues

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 dynamic payments.

Table 4-27 Top 10 energy uplift credits units (By percent of total system): 2001 through 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%
2012	22.7%	0.7%
2013	38.0%	0.7%

Table 4-28 Top 10 units and organizations energy uplift credits: 2013

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$39,068,884	60.0%	$58,869,965	90.4%
Balancing	Canceled Resources	$348,850	98.0%	$355,849	100.0%
	Generators	$149,278,224	52.8%	$250,054,898	88.5%
	Local Constraints Control	$71,358	93.4%	$76,419	100.0%
	Lost Opportunity Cost	$23,048,824	26.6%	$72,187,429	83.3%
Reactive Services		$235,940,926	69.5%	$330,586,143	97.4%
Synchronous Condensing		$161,775	40.8%	$396,377	100.0%
Black Start Services		$66,768,005	77.0%	$86,738,688	100.0%
Total		$327,278,403	38.0%	$761,093,145	88.4%

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 and it increased in 2013 compared to 2012. Table 4-27 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 38.0 percent of total energy uplift credits in 2013, compared to 22.7 percent in 2012. The increase in the concentration of energy uplift credits was in part the result of lower lost opportunity cost credits paid to combustion turbines and diesels in 2013 compared to 2012, which increased the share of credits paid to the top 10 units receiving day-ahead operating reserve, balancing operating reserve, reactive services and black start services credits.

Table 4-28 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators. The shares of the top 10 organizations in all categories separately were above 83.0 percent.

Table 4-29 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2013, 89.0 percent of all credits paid to these units were allocated to deviations while the remaining 11.0 percent were paid for reliability reasons.

Table 4-29 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2013

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$13,853,952	$2,528,270	$0	$42,266,138	$90,629,864	$0	$149,278,224
Share	9.3%	1.7%	0.0%	28.3%	60.7%	0.0%	100.0%

In 2013, concentration in all energy uplift credit categories was high.[27,28] The HHI for energy uplift credits was calculated based on each organization's daily credits for each category. Table 4-30 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 5340, for balancing operating reserve credits to generators was 3622, for lost opportunity cost credits was 4390 and for reactive services credits was 3016.

Table 4-30 Daily energy uplift credits HHI: 2013

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	5340	899	10000	100.0%	55.2%
	Imports	10000	10000	10000	100.0%	38.1%
	Load Response	10000	10000	10000	100.0%	99.2%
Balancing	Canceled Resources	10000	10000	10000	100.0%	62.2%
	Generators	3622	931	9888	99.4%	43.7%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9993	9724	10000	100.0%	97.5%
	Lost Opportunity Cost	4390	627	10000	100.0%	23.1%
Reactive Services		3016	1105	10000	100.0%	62.0%
Synchronous Condensing		8587	4133	10000	100.0%	74.0%
Black Start Services		9165	3696	10000	100.0%	110.2%
Total		1675	413	7279	85.1%	29.2%

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 seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[29] Participants can submit 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.[30] Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for day-ahead operating reserve credits.

Table 4-31 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In 2013, 4.6 percent of the total day-ahead generation was scheduled as must run by PJM, 1.2 percentage points higher than 2012.[31]

Table 4-31 Day-ahead generation scheduled as must run by PJM (GWh): 2012 and 2013

	2012			2013		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,152	1,312	1.8%	72,681	2,907	4.0%
Feb	63,642	1,191	1.9%	65,632	2,474	3.8%
Mar	60,513	1,109	1.8%	67,940	3,178	4.7%
Apr	55,999	1,099	2.0%	57,570	2,522	4.4%
May	62,986	1,944	3.1%	61,169	2,848	4.7%
Jun	69,190	1,841	2.7%	68,452	3,724	5.4%
Jul	82,984	3,618	4.4%	78,639	4,395	5.6%
Aug	76,161	2,438	3.2%	73,783	3,678	5.0%
Sep	63,535	2,902	4.6%	64,757	3,162	4.9%
Oct	60,656	3,509	5.8%	62,134	2,940	4.7%
Nov	62,985	3,542	5.6%	63,827	2,675	4.2%
Dec	68,759	2,347	3.4%	73,112	2,612	3.6%
Total	798,561	26,851	3.4%	809,695	37,115	4.6%

27 See Section 3, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

28 Table 4-30 excludes the local constraints control categories.

29 See "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>.

30 See "PJM eMkt Users Guide," Section Managing Unit Data (version November 11, 2013) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

31 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.

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. The only reason for having a day-ahead operating reserve credit is to enable the allocation of these uplift costs to transactions in the Day-Ahead Energy Market.

Table 4-32 shows the total day-ahead generation scheduled as must run by PJM by category. In 2013, 66.9 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 13.8 percent was generation from units scheduled to provide black start services, 42.0 percent was generation from units scheduled to provide reactive services and 11.1 percent was generation paid normal day-ahead operating reserve credits. The remaining 33.1 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-32 Day-ahead generation scheduled as must run by PJM by category (GWh): 2013

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	433	1,271	250	954	2,907
Feb	430	1,356	206	481	2,474
Mar	424	909	490	1,354	3,178
Apr	451	840	439	792	2,522
May	429	1,058	346	1,016	2,848
Jun	484	1,601	459	1,181	3,724
Jul	420	1,616	234	2,124	4,395
Aug	465	1,644	387	1,182	3,678
Sep	338	1,461	453	911	3,163
Oct	493	1,358	317	772	2,940
Nov	437	1,287	192	760	2,675
Dec	325	1,197	330	760	2,612
Total	5,130	15,597	4,104	12,285	37,116
Share	13.8%	42.0%	11.1%	33.1%	100.0%

Total day-ahead operating reserve credits in 2013 were $65.1 million, of which $34.9 million or 53.6 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, 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 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.[32] 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.

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.[33] 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 2013, LOC credits decreased by $105.1 million or 54.8 percent compared to 2012. The decrease of $105.1 million is comprised of a decrease of $104.6 million in day-ahead LOC and a decrease of $0.5 million in real-time LOC. Table 4-35 shows the monthly composition of LOC credits in 2012 and 2013. The reduction in LOC credits was mainly a result of lower day-ahead scheduled generation from combustion turbines and diesels that could have resulted in day-ahead LOC credits. Day-ahead scheduled generation from combustion turbines and diesels decreased by 7,259 GWh or 35.8 percent in 2013 compared to 2012.

This reduction appears to be primarily the result of the reduction in day-ahead scheduled generation in

32 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.

33 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market subtracted by 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 in balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

combination with PJM's implementation of a new tool to improve the commitment of combustion turbines (combustion turbine optimizer or CTO) which reduced the amount of generation from combustion turbines and diesels that was scheduled in the Day-Ahead Energy Market but that was not committed in real time. In 2013, 30.7 percent of the day-ahead scheduled generation from combustion turbines and diesels received LOC credits for being scheduled in the Day-Ahead Energy Market and not committed in real time, 22.2 percentage points lower than 2012.

Table 4-33 Monthly lost opportunity cost credits: 2012 and 2013

	2012			2013		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$5,165,871	$236,780	$5,402,651	$8,728,322	$2,752,980	$11,481,302
Feb	$4,523,969	$107,118	$4,631,087	$2,049,518	$2,681,143	$4,730,662
Mar	$10,523,644	$221,695	$10,745,339	$4,803,277	$2,324,036	$7,127,313
Apr	$11,843,133	$635,839	$12,478,972	$3,893,268	$1,567,916	$5,461,184
May	$15,665,485	$3,607,291	$19,272,775	$5,266,582	$3,247,955	$8,514,538
Jun	$14,570,930	$466,323	$15,037,254	$6,200,721	$807,362	$7,008,083
Jul	$27,629,292	$3,067,390	$30,696,682	$16,300,953	$3,188,446	$19,489,398
Aug	$25,561,031	$1,200,612	$26,761,643	$5,449,177	$210,367	$5,659,544
Sep	$19,962,559	$1,549,391	$21,511,950	$6,377,820	$4,579,815	$10,957,635
Oct	$12,437,131	$7,899,960	$20,337,091	$2,455,137	$619,446	$3,074,584
Nov	$14,771,088	$3,802,458	$18,573,547	$1,365,945	$701,949	$2,067,894
Dec	$5,334,673	$973,316	$6,307,989	$503,846	$559,582	$1,063,428
Total	$167,988,807	$23,768,172	$191,756,979	$63,394,565	$23,240,998	$86,635,564
Share	87.6%	12.4%	100.0%	73.2%	26.8%	100.0%

Although day-ahead LOC credits (payments to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not requested in real time) decreased in 2013 compared to 2012, it continues to comprise the majority of LOC credits. In 2013, day-ahead LOC were 73.2 percent of all LOC credits. Combustion turbines and diesels are only eligible for day-ahead lost opportunity cost if the units are scheduled in day ahead and follow PJM instructions in real time.[34] Table 4-34 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.

34 Combustion turbines and diesels with lead times of two hours or less are automatically eligible for lost opportunity cost credits. Combustion turbines and diesels with lead times greater than two hours are assumed to be committed in real time for the duration of their day-ahead schedule unless instructed not to run by PJM.

Table 4-34 Day-ahead generation from combustion turbines and diesels (GWh): 2012 and 2013

	2012			2013		
	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	579	437	375	886	633	561
Feb	758	587	546	430	206	173
Mar	1,392	1,070	918	809	395	282
Apr	1,872	1,429	1,247	684	325	256
May	1,928	1,248	1,045	1,031	387	260
Jun	2,588	1,613	1,227	1,284	696	440
Jul	3,900	1,412	979	2,950	947	748
Aug	2,358	1,380	1,119	1,772	778	544
Sep	1,635	1,167	1,031	1,219	480	295
Oct	1,079	892	796	929	451	267
Nov	1,319	1,012	819	578	213	120
Dec	851	677	624	426	109	47
Total	20,258	12,925	10,727	12,999	5,620	3,992
Share	100.0%	63.8%	53.0%	100.0%	43.2%	30.7%

In 2013, the top three control zones in which generation received LOC credits, AEP, ComEd and Dominion, accounted for 61.7 percent of all LOC credits, 55.0 percent of all the day-ahead generation from combustion turbines and diesels, 60.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 57.0 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Table 4-35 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012 and 2013

	2012			2013		
	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	$4,816,244	$349,627	$5,165,871	$8,081,096	$647,226	$8,728,322
Feb	$4,382,996	$140,973	$4,523,968	$1,860,546	$188,972	$2,049,518
Mar	$9,645,950	$877,694	$10,523,644	$2,985,098	$1,818,180	$4,803,277
Apr	$10,830,247	$1,012,886	$11,843,133	$2,476,452	$1,416,816	$3,893,268
May	$12,906,912	$2,758,573	$15,665,485	$3,615,804	$1,650,778	$5,266,582
Jun	$12,446,658	$2,124,272	$14,570,930	$4,758,076	$1,442,645	$6,200,721
Jul	$13,813,602	$13,815,690	$27,629,292	$7,462,411	$8,838,541	$16,300,952
Aug	$22,148,176	$3,412,855	$25,561,031	$3,378,510	$2,070,667	$5,449,177
Sep	$17,776,726	$2,185,833	$19,962,559	$4,200,542	$2,177,278	$6,377,820
Oct	$11,167,613	$1,269,518	$12,437,131	$2,167,106	$288,031	$2,455,137
Nov	$12,671,035	$2,100,053	$14,771,088	$846,109	$519,836	$1,365,945
Dec	$4,974,333	$360,340	$5,334,673	$192,456	$311,390	$503,846
Total	$137,580,491	$30,408,315	$167,988,806	$42,024,206	$21,370,359	$63,394,565
Share	81.9%	18.1%	100.0%	66.3%	33.7%	100.0%

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled 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 4-35 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 4-35 shows that in 2013, $42.0 million or 66.3 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 15.6 percentage points lower than 2012.

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 4-36 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 4-36 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) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2013, 67.6 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 32.4 percent was noneconomic.

Table 4-36 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2012 and 2013[35]

	2012			2013		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	308	136	444	544	121	664
Feb	422	246	668	171	53	224
Mar	800	287	1,087	269	144	413
Apr	1,125	329	1,455	225	93	318
May	874	361	1,235	228	129	357
Jun	829	662	1,491	364	272	635
Jul	823	400	1,222	713	202	915
Aug	943	397	1,340	436	275	711
Sep	880	304	1,184	293	166	459
Oct	710	191	901	256	175	431
Nov	781	276	1,057	131	64	195
Dec	434	298	732	34	59	92
Total	8,931	3,886	12,817	3,663	1,753	5,416
Share	69.7%	30.3%	100.0%	67.6%	32.4%	100.0%

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs (LOC) calculations consistent throughout the PJM rules.[36] PJM and the MMU jointly proposed two specific modifications.[37] The MMU also believes that two additional modifications would be appropriate but the MMU did not formally recommend these to the MIC for consideration although they were brought to the attention of the MIC.

- **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 than the day-ahead LMP. In the Day-Ahead Energy

35 The total generation in Table 4-36 is lower than the day-ahead generation not requested in real time in Table 4-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-36 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

36 See "Meeting Minutes," from the Market Implementation Committee (February 17, 2012). <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>.

37 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>.

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 4-37 shows the impact that each of these changes would have had on the LOC credits in the Energy Market in 2013, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $22.8 million, or 26.3 percent, if all these changes had been implemented.[38]

Table 4-37 Impact on energy market lost opportunity cost credits of rule changes: 2013

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$23,240,998	$63,394,565	$86,635,563
Impact 1: Committed Schedule	$1,186,428	$18,944,558	$20,130,986
Impact 2: Eliminating DA LMP	NA	($453,018)	($453,018)
Impact 3: Using Offer Curve	($1,198,276)	$7,553,265	$6,354,989
Impact 4: Including No Load Cost	NA	($37,440,979)	($37,440,979)
Impact 5: Including Startup Cost	NA	($11,353,697)	($11,353,697)
Net Impact	($11,848)	($22,749,871)	($22,761,719)
Credits After Changes	$23,229,150	$40,644,694	$63,873,844

The MMU is also proposing other rule changes regarding the calculation of LOC credits to units scheduled in the Day-Ahead Energy Market and not committed in real time.

- **Intra-hour LOC:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. Market settlements in PJM are based on hourly integrated values. The hourly integrated value of generation is the average power produced within an hour. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units are scheduled in the Day-Ahead Energy Market when their cleared output is greater than zero. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero, the unit was committed during that hour. In real time, a unit may be committed for part of

38 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.

an hour. The LOC compensation calculation does not take into account the exact time at which the unit was turned on. For example, a unit does not receive LOC compensation if it is scheduled in the Day-Ahead Energy Market for one specific hour and that unit is committed in real time for only the last five minutes of the hour. The MMU recommends that the calculation of LOC for units scheduled in the Day-Ahead Energy Market and not committed in real time account for committed or decommitted status within the hour.

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 could 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.[39]

In 2013, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $86.4 million, and 95.0 percent of these costs was paid by peak transmission use in the AEP Control Zone while the remaining 5.0 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 $9.65 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 $0.06 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.[40] PJM also approved new rules concerning black start service procurement, and the new selection process will be effective on April 1, 2015.[41,42]

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

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.[43] 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.

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 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.[44,45]

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

40 See "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>.

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

42 See PJM.Manual 14D: Generator Operational Requirement, Revision 26 (November 1, 2013) at "Section 10: Black Start Generation Procurement".

43 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.

44 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.

45 See the ATSI Interface definition at <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>.

the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift attributable to 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.[46]

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 energy uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.

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.

At the end of December 2013, PJM began to schedule fewer units in the BGE and Pepco control zones for reactive support.[47] 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 for reactive units.[48] These actions eliminated energy uplift costs attributable to the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 26, 2013. As these actions were just a few days before the end of 2013 and system conditions were unusual in January 2014, additional analysis is needed for a better assessment.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[49] 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 2013, units providing reactive services were paid $8.2 million in balancing operating reserve credits in order to cover their total energy offer. In 2012, this misallocation was $18.6 million, for a total of $26.7 million in the last two years.

On October 10, 2012 and November 7, 2012, the MMU presented this issue at PJM's Market Implementation

46 See "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>

47 See "Reactive Charges Update," PJM Presentation at the Market Implementation Committee (January 8, 2014) <http://www.pjm.com/committees-and-groups/committees/mic.aspx>.

48 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.

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

Committee (MIC).[50] [51] The MIC endorsed the issue charge and approved merging this issue with the long term solution for the allocation of the cost of day-ahead operating reserves for reliability.[52]

The MMU had previously proposed changes to the way reactive services credits are calculated and how reactive services charges are allocated. The MMU continues to recommend that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also continues to recommend 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.[53]

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.[54] 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.[55] 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.

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on operating reserve rates if up-to congestion transactions had paid operating reserve charges based on deviations in the same way that increment offers and decrement

50 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," MMU Problem Statement to the Market Implementation Committee (October 10, 2012). <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>.

51 See "Minutes," from the Market Implementation Committee (November 7, 2012). <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx>.

52 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}>.

53 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>

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

55 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" at "Energy Uplift" for a full description of balancing operating reserve locations.

bids do, while accounting for the impact of such payments on the profitability of the transactions.

In 2013, 53.1 percent of all up-to congestion transactions were profitable.

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied and the other identified quantifiable recommendations had been implemented. It was assumed that up-to congestion transactions would have maintained the same shares of profitable and unprofitable transactions after paying operating reserve charges as when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, 66.7 percent of all up-to congestion transactions would have been made. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. Up-to congestion transactions would have paid an average rate between \$0.276 and \$0.377 per MWh in 2013 if the MMU's recommendations regarding operating reserves had been in place.[56]

Quantifiable Recommendations Impact

The MMU calculated the impact that all quantifiable recommendations would have had on the operating reserve rates paid by participants in the RTO, Eastern and Western regions. For reasons of confidentiality, these impacts cannot be disaggregated by issue. Five recommendations have been aggregated in this analysis: reallocation of operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts; reallocation of no load and startup costs of units providing reactive services; implementation of the proposed changes to lost opportunity cost calculations; elimination of internal bilateral transactions from the deviations calculation; and the allocation of operating reserve charges to up-to congestion transactions.

Table 4-38 shows the combined impact that these recommendations would have had on all operating reserve rates in 2013. The reduction in the rates is due to a decrease of 41.7 percent of the credits used to calculate these rates and a weighted average increase of 655.3 percent in the denominator used to calculate these rates.[57]

Table 4-38 MMU recommendations impact on operating reserve rates: 2013

	Current Rates (\$/MWh)	Proposed Rates (\$/MWh)	Difference (\$/MWh)	Percentage Difference
Day-Ahead	0.079	0.027	(0.052)	(65.8%)
RTO Reliability	0.051	0.036	(0.015)	(29.9%)
East Reliability	0.030	0.030	0.000	0.0%
West Reliability	0.004	0.004	0.000	0.0%
RTO Deviations	0.863	0.058	(0.805)	(93.2%)
East Deviations	1.868	0.061	(1.807)	(96.7%)
West Deviations	0.122	0.012	(0.110)	(90.3%)
Lost Opportunity Cost	0.705	0.052	(0.653)	(92.6%)
Canceled Resources	0.003	0.000	(0.003)	(90.0%)

Table 4-39 shows the operating reserve cost of a 1 MW transaction had these recommendations been implemented in 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of \$0.202 per MWh, \$3.099 per MWh or 93.9 percent less than the actual average rate paid. Any up-to congestion transactions sourced in the Eastern Region and sinking at the Western Region would have been charged an average rate of \$0.327 per MWh. Table 4-39 illustrates the current and proposed average operating reserve rates for all transactions.

Table 4-39 Current and proposed average operating reserve rate by transaction: 2013

	Transaction	Current Rates (\$/MWh)	Proposed Rates (\$/MWh)	Change (\$/MWh)	Change (%)
East	INC	3.198	0.176	(3.022)	(94.5%)
	DEC	3.301	0.202	(3.099)	(93.9%)
	DA Load	0.103	0.026	(0.077)	(74.6%)
	RT Load	0.073	0.057	(0.016)	(22.5%)
	Deviation	3.198	0.176	(3.022)	(94.5%)
West	INC	1.561	0.125	(1.436)	(92.0%)
	DEC	1.664	0.151	(1.513)	(90.9%)
	DA Load	0.103	0.026	(0.077)	(74.6%)
	RT Load	0.053	0.036	(0.016)	(31.4%)
	Deviation	1.561	0.125	(1.436)	(92.0%)
UTC	East to East	NA	0.377		
	West to West	NA	0.276		
	East to/from West	NA	0.327		

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

57 The weighted average was calculated based on the total charges by rate.

Confidentiality of Energy Uplift Information

PJM rules require all data posted publicly by PJM or the MMU to comply with existing confidentiality rules. Current confidentiality rules do not appear to allow posting data containing three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[58]

Energy uplift are out of market, non-transparent payments made to resources operating on the behalf of PJM to provide transmission constraint relief or other reliability services. 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. 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 very effective barrier to entry. The MMU recommends that PJM revise the current energy uplift operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for energy uplift payments in the PJM region. This information would include the publication of energy uplift information by zone, by owner and by resource.

Operating Reserve Credits Recommendations

Day-Ahead Operating Reserve Credits

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. 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.[59]

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. In the same way, if units are dispatched in real time by PJM below their day-ahead scheduled output, they could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss because real-time LMP is greater than the day-ahead LMP or they could be paid energy uplift in the form of lost opportunity cost credits if by decreasing their output units lose profit because real-time LMP is greater than their offers. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their profits in real time.

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 generation is lower than their day-ahead scheduled generation which

58 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 9 (July 22, 2012), Market Data Posting.

59 Balancing operating reserve credit calculation uses the net DASR revenues, net synchronized reserve revenues, net non-synchronized reserve revenues and reactive services revenues.

subsequently results in reduced losses do not have a reduction in 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 or not, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM 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.

The MMU recommends 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 when their operation results in reduced losses. The MMU calculated the impact of this recommendation in 2013 and estimated a decrease of $25.5 million in day-ahead operating reserve credits or 5.8 percent ($13.4 million paid to units providing reactive support and $5.0 million paid to units providing black start support, the remaining $7.1 were normal day-ahead operating reserves) and an increase of $0.2 million in balancing operating reserve credits. This estimate was calculated using the current settlement database which is not structured to account for this rule change.

Net DASR Revenues Offset

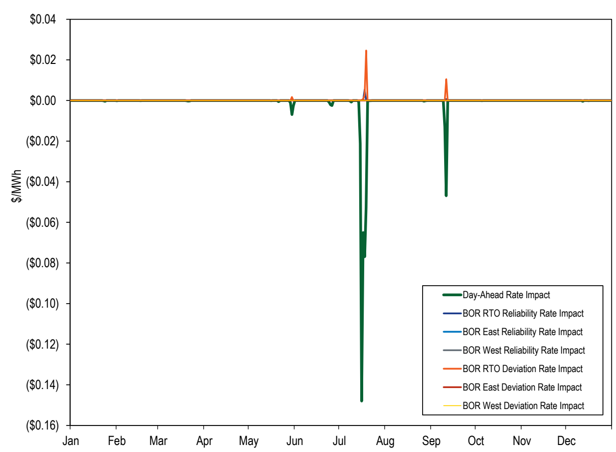
Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM at a loss. The current rules determine whether a unit is scheduled at a loss by comparing units' total offers (including no load and startup costs) to the units' day-ahead energy revenues. If day-ahead energy revenues are not enough to cover the total offer then units are made whole through day-ahead operating reserve credits.

This determination of whether a unit is scheduled at a loss is inaccurate because it does not take into account all the revenues received in the Day-Ahead Energy Market. The PJM Day-Ahead Energy Market includes a joint procurement of energy and day-ahead scheduling reserves (DASR).[60] The current rules governing day-ahead operating reserve credits do not include the net revenues from the DASR Market in units' revenues. The net DASR revenues equal gross DASR revenues minus DASR offer (which includes lost opportunity cost). The current rules do include net DASR revenues in the balancing operating reserve credit calculation.

The result of not including the net DASR revenues in the day-ahead operating reserve credit calculation is that resources scheduled to provide day-ahead scheduling reserves may appear to be scheduled to operate at a loss when they are not. This issue only becomes relevant whenever the DASR clearing price is above zero. In 2013, the DASR price reached $1 per MW or more during 114 hours or 1.3 percent of the time.

The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits. In 2013, this recommendation would have had a net impact of a $1.2 million reduction, comprised of a $1.3 million decrease in day-ahead operating reserve credits and an increase of $0.1 million increase in balancing operating reserve credits. Balancing operating reserve credits increase because the current rules ensure that resources do not operate at a loss, which means that if revenues from the Day-Ahead Energy Market, plus revenues or charges from the Balancing Energy Market, net revenues from a subset of ancillary services are not enough to cover a units offer based on their real-time operation, such units are made whole to their offers. Figure 4-6 shows the impact this recommendation would have had on the day-ahead operating reserve and balancing operating reserve rates.

Figure 4-6 Impact of net DASR net revenues offset change on daily operating reserve rates ($/MWh): 2013



60 See *2013 State of the Market Report for PJM*, Section 10, "Ancillary Service Markets," at "Day-Ahead Scheduling Reserve (DASR)," for an explanation of this service.

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. 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.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2013, 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 $13.0 million, of which $11.7 million or 89.7 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.

Self-Startup

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[61] 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. Self-scheduled units may 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 not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. This issue was not significant in 2013 since it only had an impact of $0.2 million among a small number of units, but it is important to establish rules that properly compensate resources.

2013 Energy Uplift Charges Increase

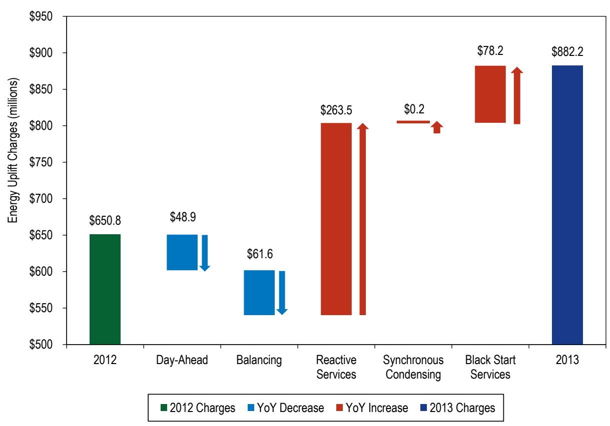
Energy uplift charges increased by $231.4 million, from $650.8 million in 2012 to $882.2 million in 2013. This change resulted from an increase of $263.5 million in reactive services charges, an increase of $78.2 million in black start services charges and an increase of $0.2 million in synchronous condensing charges. These

61 See "PJM eMkt Users Guide," Section Managing Unit Data (version November 11, 2013) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

increases were partially offset by a decrease of $48.9 million in day-ahead operating reserve charges and a decrease of $61.6 million in balancing operating reserve charges.

Figure 4-7 shows the net impact of each category on the change in total energy uplift charges from the 2012 level to the 2013 level. The outside bars show the 2012 total energy uplift charges (left side) and the 2013 total energy uplift charges (right side). The bars in between show the year over year change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in 2013 compared to 2012 (a decrease of $48.9 million).

Figure 4-7 Energy uplift charges change from 2012 to 2013 by category



The main contributing factors of the $231.4 million increase in energy uplift charges in 2013 compared to 2012 were the impact of FMU adders included in the offers of units providing reactive support ($81.7 million) and colder winter days in 2013 compared to 2012 ($88.0 million). Even though these were the two most relevant factors for the increase in energy uplift charges, the change in unit scheduling/commitment and allocation of energy uplift charges related to black start and reactive support had different impacts on each category of energy uplift. Day-ahead and balancing operating reserve charges were significantly reduced while reactive services and black start services charges increased. The net impact of the change in unit scheduling/commitment and allocation was an increase of $21.1 million.

In September 2012, PJM began to schedule in the Day-Ahead Energy Market units out of merit (must run) needed for black start and reactive support in real time. Before September 2012, these units were being committed out of merit in real time after PJM, through the reliability assessment commitment run (RAC), identified that these units were needed for those services. Because the day-ahead energy model does not capture the need to schedule units for black start or reactive support, these units were not normally scheduled in the Day-Ahead Energy Market but committed in real time.[62] The MMU supported the concept of PJM's change in unit scheduling/commitment since it improved market efficiency.

The change in unit scheduling/commitment had a significant impact on the allocation of the energy uplift charges associated with units needed for black start and reactive support. The unit scheduling/commitment change shifted substantial energy uplift charges from the balancing operating reserves and reactive services to day-ahead operating reserves. That shift was significant because balancing operating reserve charges, reactive services charges and day-ahead operating reserve charges are allocated differently. Balancing operating reserve charges are paid by real-time load and real-time exports or by deviations from the day ahead depending on the allocation process. Balancing operating reserve charges are allocated across three different regions. Reactive services charges are paid by real-time load on a zonal level. Day-ahead operating reserve charges are paid by day-ahead load, day-ahead exports and decrement bids across the entire RTO Region.

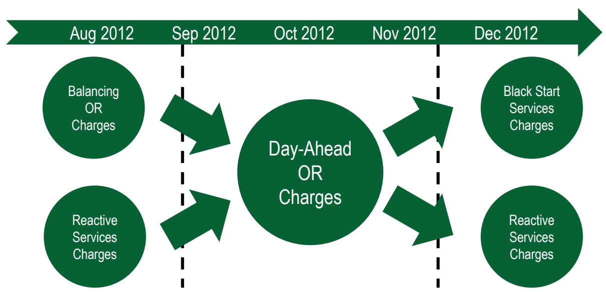
In December 2012, PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for black start and reactive support.[63] The proposed revisions allocated the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide black start service as determined by Schedule 6A of the OATT and the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide reactive service or transfer interface

62 These units would clear the Day-Ahead Energy Market normally only when they are economic.
63 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

control would be allocated zonally in proportion to the real-time deliveries of energy to load.

Figure 4-8 shows a diagram of how the energy uplift charges related to units needed for black start and reactive support changed in 2012. Before September 2012, these charges were allocated as balancing operating reserve charges or reactive services charges. Between September and November 2012, these charges were allocated as day-ahead operating reserve charges. After November 2012 these costs are being allocated as black start services charges or reactive services charges.

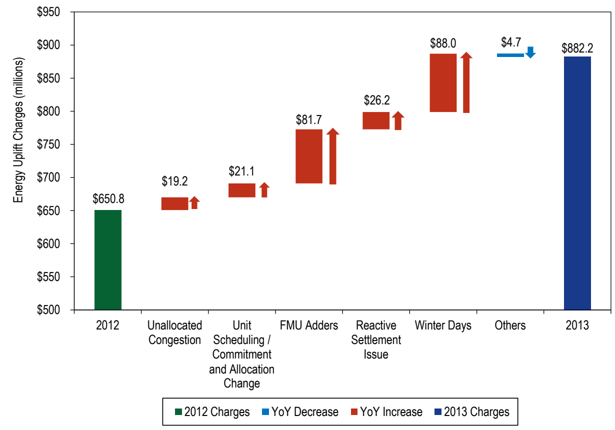
Figure 4-8 Allocation changes of energy uplift charges associated with units needed for black start and reactive support



Other factors that contributed to the increase in energy uplift charges were unallocated congestion charges and the reactive services credits settlement issue.[64] Unallocated congestion charges increased by $19.2 million, from $0.8 million in 2012 to $20.0 million in 2013. PJM also announced a settlement issue created due to an unintended logging error regarding units scheduled in the Day-Ahead Energy Market for reactive support in the second half of 2013, the estimated impact of this issue is $26.2 million.

Figure 4-9 shows the impact that each issue had on the change in energy uplift charges from 2012 to 2013. For example, the second bar from the left shows that unallocated congestion charges increased energy uplift charges by $19.2 million in 2013 when compared to 2012.

Figure 4-9 Energy uplift charges change from 2012 to 2013 by issue



64 See "Item 03 – Reactive Charges Update," PJM Presentation to the Energy Market Uplift Senior Task Force (January 16, 2014) for more detail on the reactive credit settlement issue. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140116/20140116-item-03-reactive-charges-update.ashx>

