Energy Uplift (Operating Reserves)

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

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by $96.3 million or 11.1 percent in 2014 compared to 2013, from $868.4 million to $964.7 million. In 2014, the single largest factor was the $410.4 million increase in balancing operating reserve charges for reliability in the first three months of the year.
- **Energy Uplift Charges Categories:** The increase of $96.3 million in 2014 is comprised of a $25.1 million increase in day-ahead operating reserve charges, a $407.2 million increase in balancing operating reserve charges, a $282.0 million decrease in reactive services charges, a $0.3 million decrease in synchronous condensing charges and a $53.7 million decrease in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.134 per MWh. The balancing operating reserve reliability rates averaged $0.540, $0.018 and $0.008 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $1.159, $0.330 and $0.125 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $1.229 per MWh and the canceled resources rate averaged $0.010 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and PENELEC control zones had the three highest reactive local voltage support rates: $0.395, $0.177 and $0.177 per MWh. The reactive transfer interface support rate averaged $0.001 per MWh.
- **Energy Uplift Costs:** In the Eastern Region, a decrement bid paid an average of $2.424 per MWh, real-time load paid an average of $0.450 per MWh and deviations either from generators, load or interchange paid an average of $2.295 per MWh. In 2014, in the Western Region, a decrement bid paid an average of $2.219 per MWh, real-time load paid an average of $0.439 per MWh and deviations either from generators, load or interchange paid an average of $2.089 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 32.9 percent of all day-ahead generator credits and 56.2 percent of all balancing generator credits. Combustion turbines and diesels received 69.8 percent of the lost opportunity cost credits. Coal units received 83.7 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.6 percent of all credits. The top 10 organizations received 80.7 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4682, balancing operating reserves HHI was 3142, lost opportunity cost HHI was 4070 and reactive services HHI was 7315.
- **Economic and Noneconomic Generation.** In 2014, 87.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2014, 4.1 percent of the total day-ahead generation was scheduled as must run by PJM, of which 35.5 percent received energy uplift payments.

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

2 Other types of energy uplift charges are make whole payments to emergency demand response resources and emergency transaction purchases.

Geography of Charges and Credits

- In 2014, 90.6 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 generation, 2.2 percent by transactions at hubs and aggregates and 7.2 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2014, lost opportunity cost credits increased by $72.8 million compared to 2013. In 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 53.2 percent of all lost opportunity cost credits, 47.3 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 56.2 percent of all day-ahead generation not committed in real time by PJM from those unit types and 66.4 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units.** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $32.6 million, a decrease of $53.7 million compared to 2013.
- **Con Edison – PJM Transmission Service Agreements Support.** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations.** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in 2014, the average rate paid by a DEC in the Eastern Region would have been $0.223 per MWh, which is $2.201 per MWh, or 90.8 percent, lower than the actual average rate paid.

Recommendations

- The MMU recommends that PJM not use closed loop interfaces to set zonal prices, rather than use nodal prices, to accommodate the inadequacies of the demand side resource capacity product or the inability of the LMP model to fully accommodate reactive issues. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that closed loop interfaces be implemented only after such analysis, only after significant advance notice to the markets and only if the result is consistent with energy market fundamentals. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants to be made aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2012. Status: Adopted partially.)
- 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 credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.

(Priority: Medium. First reported 2013. Status: Not adopted.)

- 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. (Priority: High. First reported 2012. Status: Not adopted.)
  - 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. (Priority: Medium. First reported 2012. Status: Not adopted.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Status: Not adopted.)
  - The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends including real-time exports and real-time wheels 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. (Priority: Low. First reported Q2, 2014. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q1, 2014. Status: Not adopted.)

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. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. 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

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>.

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.

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

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

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

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

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 PJM. "Manual 28: Operating Agreement Accounting," Revision 68, Section 5.2.3 Credits for Synchronous Condensing (January 16, 2015).

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 PJM. 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-minute 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-minute 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-minute 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-minute 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-minute 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-minute 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

Day-Ahead	Deviations	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

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

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.

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 11.1 percent in 2014, compared to 2013, to a total of $964.7 million. Table 4-6 shows total energy uplift charges from 1999 through 2014.[11]

Table 4-6 Total energy uplift charges: 1999 through 2014

	Total Energy Uplift Charges (Millions)	Annual Change (Millions)	Annual Percent Change	Energy Uplift as a Percent of Total PJM Billing
1999	$133.9	NA	NA	7.5%
2000	$217.0	$83.1	62.1%	9.6%
2001	$284.0	$67.1	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.5%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.5)	(32.0%)	1.2%
2010	$622.8	$300.1	93.0%	1.8%
2011	$605.0	($17.8)	(2.9%)	1.7%
2012	$640.6	$35.6	5.9%	2.2%
2013	$868.4	$227.8	35.6%	2.6%
2014	$964.7	$96.3	11.1%	1.9%

Total energy uplift charges increased by $96.3 million or 11.1 percent in 2014 compared to 2013. Table 4-7 compares energy uplift charges by category for 2013 and 2014. The increase of $96.3 million in 2014 is comprised of an increase of $25.1 million in day-ahead operating reserve charges, an increase of $407.2 million in balancing operating reserve charges, a decrease of $282.0 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $53.7 million in black start services charges. The increase in total energy uplift charges was a result of high demand, high natural gas costs and high LMPs in the first quarter. High natural gas prices and higher energy offers for units scheduled in the Day-Ahead Energy Market and units committed in real time for conservative operations increased the day-ahead and balancing operating reserve charges. Higher energy prices reduced the energy uplift for coal units providing black start and reactive support in the first quarter. In contrast, low demand and low natural gas prices during the second and third quarters reduced energy uplift charges.

Table 4-7 Energy uplift charges by category: 2013 and 2014

Category	2013 Charges (Millions)	2014 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$86.3	$111.4	$25.1	29.2%
Balancing Operating Reserves	$383.6	$790.8	$407.2	106.2%
Reactive Services	$311.4	$29.4	($282.0)	(90.6%)
Synchronous Condensing	$0.4	$0.1	($0.3)	(73.8%)
Black Start Services	$86.7	$33.0	($53.7)	(61.9%)
Total	$868.4	$964.7	$96.3	11.1%

The increase in energy uplift charges in 2014 was a result of increases in January. Total energy uplift charges increased $486.9 million in January 2014, compared to January 2013, while energy uplift charges decreased by $390.6 million in February through December 2014 compared to February through December 2013. Table 4-8 compares monthly energy uplift charges by category for 2013 and 2014.

11 Table 4-6 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 22, 2015.

Table 4-8 Monthly energy uplift charges: 2013 and 2014

	2013 Charges (Millions)						2014 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$11.1	$79.3	$23.6	$0.0	$8.5	$122.4	$35.8	$565.7	$3.8	$0.1	$4.0	$609.4
Feb	$5.1	$67.1	$17.6	$0.0	$7.0	$96.9	$9.5	$56.1	$1.0	$0.0	$0.9	$67.5
Mar	$6.7	$17.4	$14.4	$0.0	$6.8	$45.2	$5.7	$59.5	$2.7	$0.0	$2.6	$70.5
Apr	$5.7	$23.4	$13.7	$0.0	$9.2	$52.1	$4.2	$9.7	$5.3	$0.0	$2.8	$22.0
May	$12.5	$22.5	$17.2	$0.0	$8.7	$60.9	$6.4	$21.0	$5.3	$0.0	$1.8	$34.5
Jun	$10.1	$17.9	$22.1	$0.0	$8.0	$58.0	$5.3	$15.9	$4.2	$0.0	$2.1	$27.4
Jul	$8.3	$43.5	$19.6	$0.4	$5.9	$77.7	$6.7	$11.5	$2.9	$0.0	$4.4	$25.5
Aug	$4.2	$14.7	$27.8	$0.0	$7.6	$54.2	$5.8	$9.9	$1.0	$0.0	$4.1	$20.8
Sep	$12.0	$31.1	$27.5	$0.0	$7.4	$78.1	$8.0	$12.5	$1.3	$0.0	$3.9	$25.6
Oct	$2.5	$12.8	$41.7	$0.0	$6.7	$63.7	$9.5	$9.8	$0.8	$0.0	$2.6	$22.8
Nov	$2.8	$17.7	$42.7	$0.0	$6.7	$69.9	$5.6	$10.1	$0.5	$0.0	$1.4	$17.6
Dec	$5.3	$36.2	$43.5	$0.0	$4.4	$89.3	$9.0	$9.1	$0.6	$0.0	$2.3	$21.1
Total	$86.3	$383.6	$311.4	$0.4	$86.7	$868.4	$111.4	$790.8	$29.4	$0.1	$33.0	$964.7
Share	9.9%	44.2%	35.9%	0.0%	10.0%	100.0%	11.5%	82.0%	3.1%	0.0%	3.4%	100.0%

Table 4-9 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[12,13] Day-ahead operating reserve charges increased by $25.1 million or 29.2 percent in 2014 compared to 2013. Day-ahead operating reserve charges (excluding unallocated congestion charges) increased by $47.3 million or 74.0 percent in 2014 compared to 2013. This increase was primarily the result of a change in the scheduling/commitment of a set of units in the BGE and Pepco control zones that provided reactive support to the 500 kV transmission system in 2013 and provided congestion relief to thermal constraints in 2014. In addition, higher natural gas prices and higher energy offers in January resulted in higher day-ahead operating reserve charges. There were zero unallocated congestion charges in 2014 compared to $22.2 million in 2013.

Table 4-9 Day-ahead operating reserve charges: 2013 and 2014

Type	2013 Charges (Millions)	2014 Charges (Millions)	Change (Millions)	2013 Share	2014 Share
Day-Ahead Operating Reserve Charges	$64.0	$111.4	$47.4	74.2%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Unallocated Congestion Charges	$22.2	$0.0	($22.2)	25.7%	0.0%
Total	$86.3	$111.4	$25.1	100.0%	100.0%

Table 4-10 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $407.26 million in 2014 compared to 2013. This increase was a result of high balancing operating reserve charges in January. Balancing operating reserve charges increased by $486.4 million in January 2014 compared to January 2013. Balancing operating reserve decreased by $79.2 million from February through December 2014 compared to February through December 2013. This increase was primarily the result of higher natural gas prices and higher energy offers combined with significantly higher conservative operations commitment, lost opportunity cost compensation to generators scheduled in the Day-Ahead Energy Market and not committed in real time, and lost opportunity cost compensation to generators reduced in real time for reliability purposes.

12 See PJM. 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.

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

Table 4-10 Balancing operating reserve charges: 2013 and 2014

Type	2013 Charges (Millions)	2014 Charges (Millions)	Change (Millions)	2013 Share	2014 Share
Balancing Operating Reserve Reliability Charges	$55.8	$447.1	$391.3	14.5%	56.5%
Balancing Operating Reserve Deviation Charges	$327.0	$341.7	$14.7	85.2%	43.2%
Balancing Operating Reserve Charges for Load Response	$0.7	$0.0	($0.7)	0.2%	0.0%
Balancing Local Constraint Charges	$0.1	$1.9	$1.8	0.0%	0.2%
Total	$383.6	$790.8	$407.2	100.0%	100.0%

Table 4-11 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In 2014, 52.8 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 20.4 percentage points compared to the share in 2013.

Table 4-11 Balancing operating reserve deviation charges: 2013 and 2014

Charge Attributable To	2013 Charges (Millions)	2014 Charges (Millions)	Change (Millions)	2013 Share	2014 Share
Make Whole Payments to Generators and Imports	$239.2	$180.3	($58.9)	73.2%	52.8%
Energy Lost Opportunity Cost	$87.3	$160.1	$72.8	26.7%	46.9%
Canceled Resources	$0.5	$1.3	$0.9	0.1%	0.4%
Total	$327.0	$341.7	$14.7	100.0%	100.0%

Table 4-12 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $282.0 million in 2014 compared to 2013. Black start services charges decreased by $53.7 million in 2014 compared to 2013. Both categories decreased primarily as a result of the fact that higher energy prices made the units more economic than in 2013. Reduced FMU adders decreased the amount of energy uplift paid to units providing reactive support. The removal of automatic load rejection black start units from must run black start status contributed to the reduction in the amount of energy uplift paid to units providing black start support in 2014.

Table 4-12 Additional energy uplift charges: 2013 and 2014

Type	2013 Charges (Millions)	2014 Charges (Millions)	Change (Millions)	2013 Share	2014 Share
Reactive Services Charges	$311.4	$29.4	($282.0)	78.1%	47.1%
Synchronous Condensing Charges	$0.4	$0.1	($0.3)	0.1%	0.2%
Black Start Services Charges	$86.7	$33.0	($53.7)	21.8%	52.8%
Total	$398.5	$62.5	($336.0)	100.0%	100.0%

Table 4-13 and Table 4-14 show the amount and percentages of regional balancing charges in2013 and 2014. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by real-time load. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2014, regional balancing operating reserve charges increased by $406.1 million compared to 2013. Balancing operating reserve reliability charges increased by $391.3 million or 701.4 percent and balancing operating reserve deviation charges increased by $14.7 million or 4.5 percent.

Table 4-13 Regional balancing charges allocation (Millions): 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$41.8	10.9%	$10.8	2.8%	$1.8	0.5%	$54.4	14.2%
	Real-Time Exports	$1.1	0.3%	$0.3	0.1%	$0.0	0.0%	$1.4	0.4%
	Total	$42.9	11.2%	$11.1	2.9%	$1.8	0.5%	$55.8	14.6%
Deviation Charges	Demand	$121.6	31.8%	$72.3	18.9%	$3.9	1.0%	$197.8	51.7%
	Supply	$32.9	8.6%	$19.2	5.0%	$1.1	0.3%	$53.2	13.9%
	Generator	$49.7	13.0%	$24.3	6.3%	$2.0	0.5%	$76.0	19.9%
	Total	$204.1	53.3%	$115.8	30.3%	$7.0	1.8%	$327.0	85.4%
Total Regional Balancing Charges		$247.0	64.5%	$126.9	33.2%	$8.9	2.3%	$382.8	100%

Table 4-14 Regional balancing charges allocation (Millions): 2014

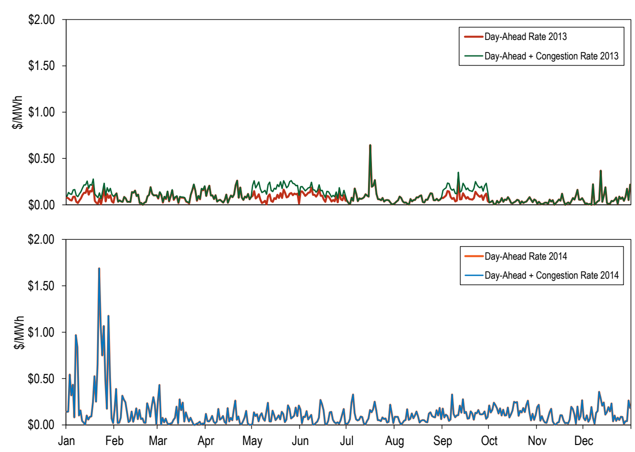
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$429.3	54.4%	$6.7	0.9%	$3.3	0.4%	$439.3	55.7%
	Real-Time Exports	$7.5	1.0%	$0.2	0.0%	$0.1	0.0%	$7.8	1.0%
	Total	$436.8	55.4%	$7.0	0.9%	$3.4	0.4%	$447.1	56.7%
Deviation Charges	Demand	$172.9	21.9%	$12.4	1.6%	$4.8	0.6%	$190.0	24.1%
	Supply	$47.7	6.0%	$3.6	0.5%	$1.0	0.1%	$52.3	6.6%
	Generator	$91.9	11.7%	$5.2	0.7%	$2.3	0.3%	$99.4	12.6%
	Total	$312.4	39.6%	$21.2	2.7%	$8.1	1.0%	$341.7	43.3%
Total Regional Balancing Charges		$749.2	95.0%	$28.2	3.6%	$11.5	1.5%	$788.8	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.[14]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2013 and 2014. The average rate in 2014 was $0.134 per MWh, $0.057 per MWh higher than the average in 2013. The highest rate occurred on January 22, when the rate reached $1.689 per MWh, $1.043 per MWh higher than the $0.646 per MWh reached in 2013, on July 16. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2014.The increase in the day-ahead operating reserve rate on January 22 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 50 percent of their scheduled run time. On January 22, 116 units received day-ahead operating reserve credits, 86 were economic for 50 percent or less of their scheduled run time. That was the highest number of units scheduled noneconomic in the Day-Ahead Energy Market in 2014. Also, on January 22, 60 units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; eight of these units received enough net revenues from day-ahead scheduling reserves to cover their total energy offer (including no load and startup cost), which would have resulted in zero day-ahead operating reserve credits if the net revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[15]

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



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

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

Figure 4-2 shows the RTO and the regional reliability rates for 2013 and 2014. The average daily RTO reliability rate was $0.540 per MWh. The highest RTO reliability rate in 2014 occurred on January 28, when the rate reached $24.593 per MWh, $23.791 per MWh higher than the $0.802 per MWh rate reached in 2013, on January 23. The increases in the RTO reliability rate on January 8 and between January 21 and 29 were the result of the commitment for conservative operations of natural gas fired generators with high offers.[16]

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

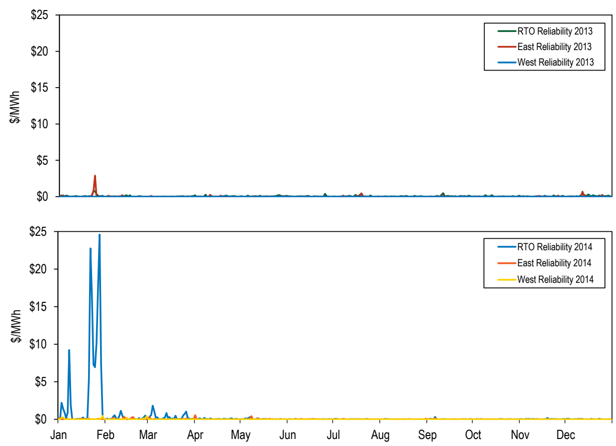


Figure 4-3 shows the RTO and regional deviation rates for 2013 and 2014. The average daily RTO deviation rate was $1.159 per MWh. The highest daily rate in 2014 occurred on January 25, when the RTO deviation rate reached $20.098 per MWh, $9.926 per MWh higher than the $10.172 per MWh rate reached in 2013, on January 23. In 2014, the RTO deviation rate increased while the Eastern Region deviation rate decreased, compared to 2013. In 2013, energy uplift was paid primarily to units committed to provide relief to local transmission constraints in the Eastern Region, while in 2014, energy uplift was paid primarily to units committed to meet overall load and provide reserves for peak hours.

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

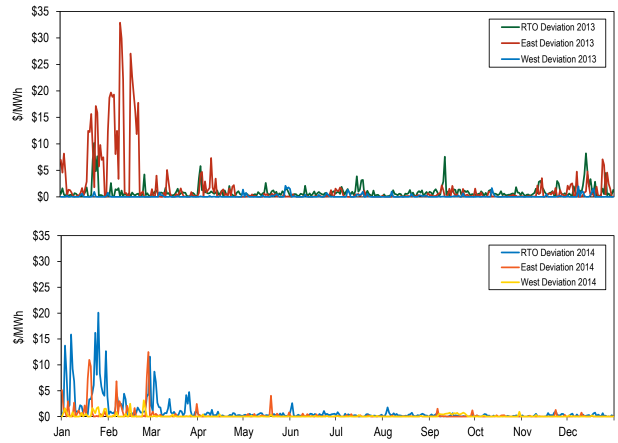
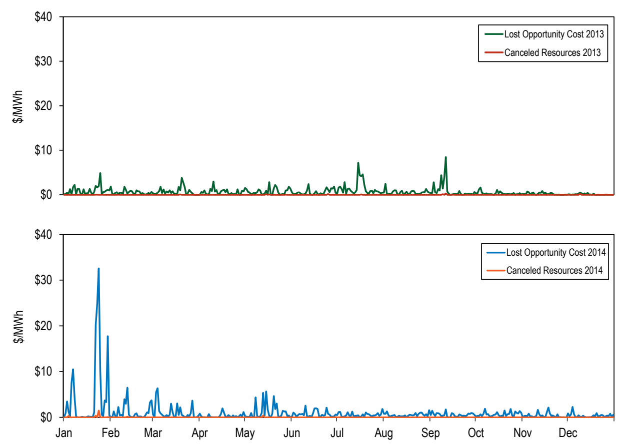


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2013 and 2014. The lost opportunity cost rate averaged $1.229 per MWh. The highest lost opportunity cost rate occurred on January 24, when it reached $32.556 per MWh, $24.078 per MWh higher than the $8.478 per MWh rate reached in 2013, on September 11. On January 24, 2014, 63.5 percent of the lost opportunity cost rate was due to units reduced in real time for reliability purposes.

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



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

Table 4-15 shows the average rates for each region in each category in 2013 and 2014.

Table 4-15 Operating reserve rates ($/MWh): 2013 and 2014

Rate	2013 ($/MWh)	2014 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.077	0.134	0.057	73.7%
Day-Ahead with Unallocated Congestion	0.104	0.134	0.030	29.0%
RTO Reliability	0.054	0.540	0.486	900.2%
East Reliability	0.029	0.018	(0.011)	(37.2%)
West Reliability	0.004	0.008	0.003	78.3%
RTO Deviation	0.946	1.159	0.213	22.5%
East Deviation	1.863	0.330	(1.532)	(82.3%)
West Deviation	0.121	0.125	0.004	2.9%
Lost Opportunity Cost	0.710	1.229	0.519	73.1%
Canceled Resources	0.004	0.010	0.007	178.7%

Table 4-16 shows the operating reserve cost of a one MW transaction in 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.424 per MWh with a maximum rate of $43.005 per MWh, a minimum rate of $0.107 per MWh and a standard deviation of $5.031 per MWh. The rates in Table 4-16 include all operating reserve charges including RTO deviation charges. Table 4-16 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 4-16 Operating reserve rates statistics ($/MWh): 2014

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	42.256	2.295	0.010	4.924
	DEC	43.005	2.424	0.107	5.031
	DA Load	1.689	0.129	0.000	0.168
	RT Load	24.630	0.450	0.000	2.358
	Deviation	42.256	2.295	0.010	4.924
West	INC	43.729	2.089	0.010	4.809
	DEC	44.478	2.219	0.107	4.917
	DA Load	1.689	0.129	0.000	0.168
	RT Load	24.652	0.439	0.000	2.358
	Deviation	43.729	2.089	0.010	4.809

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. These charges are separate from the reactive service revenue requirement charges which are a fixed annual charged based on approved FERC filings.

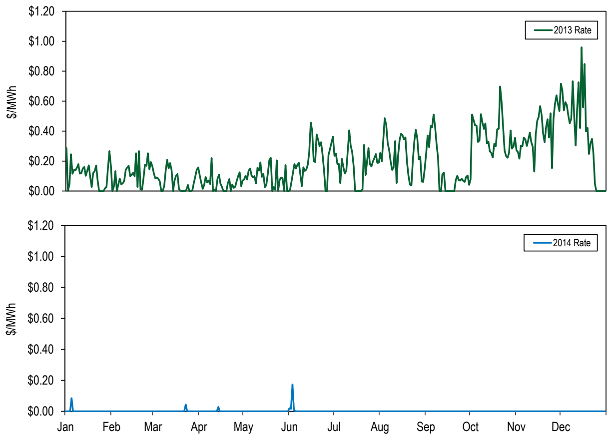
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-17 shows the reactive services rates associated with local voltage support in 2013 and 2014. Table 4-17 shows that in 2014 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.395 per MWh for reactive services associated with local voltage support, $2.058 or 83.9 percent lower than the average rate paid in 2013.

Table 4-17 Local voltage support rates: 2013 and 2014

Control Zone	2013 ($/MWh)	2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.229	0.009	(0.220)	(95.9%)
AEP	0.055	0.006	(0.049)	(89.7%)
AP	0.002	0.005	0.003	169.4%
ATSI	0.680	0.177	(0.503)	(74.0%)
BGE	0.240	0.001	(0.239)	(99.7%)
ComEd	0.001	0.000	(0.001)	(68.7%)
DAY	0.000	0.001	0.001	NA
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.021	0.044	0.024	112.8%
DPL	2.453	0.395	(2.058)	(83.9%)
EKPC	0.006	0.000	(0.006)	(100.0%)
JCPL	0.006	0.001	(0.005)	(89.1%)
Met-Ed	0.346	0.002	(0.344)	(99.4%)
PECO	0.021	0.008	(0.013)	(60.5%)
PENELEC	0.030	0.185	0.155	514.7%
Pepco	1.884	0.001	(1.883)	(100.0%)
PPL	0.011	0.000	(0.011)	(99.5%)
PSEG	0.016	0.008	(0.008)	(47.5%)
RECO	0.182	0.000	(0.182)	(100.0%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2013 and 2014. The average rate in 2014 was $0.001 per MWh, 99.5 percent lower than the $0.194 per MWh average rate in 2013. In 2014, energy uplift was paid to units providing support to the reactive transfer interfaces for only seven days. The significant decrease in reactive services charges allocated across the RTO was a result of the fact that units that were previously scheduled noneconomic to provide reactive services became economic based on higher energy prices and lower offers from the units providing reactive support due to reduced FMU adders, and therefore cleared the Day-Ahead Energy Market based on economics for thermal constraints.

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



Balancing Operating Reserve Determinants

Table 4-18 shows the determinants used to allocate the regional balancing operating reserve charges in 2013 and 2014. Total real-time load and real-time exports were 14,300,277 MWh or 1.8 percent higher in 2014 compared to 2013. Total deviations summed across the demand, supply, and generator categories were 7,294,607 MWh or 5.9 percent higher in 2014 compared to 2013.

Table 4-18 Balancing operating reserve determinants (MWh): 2013 and 2014

		Reliability Charge Determinants			Deviation Charge Determinants			
		Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2013	RTO	773,789,714	21,004,033	794,793,747	72,878,134	19,569,028	30,495,661	122,942,823
	East	366,566,019	9,763,023	376,329,041	38,923,609	9,796,083	13,468,589	62,188,281
	West	407,223,695	11,241,010	418,464,705	31,767,749	9,188,844	17,027,072	57,983,665
2014	RTO	780,507,569	28,586,455	809,094,024	78,153,451	19,991,280	32,092,699	130,237,430
	East	366,534,760	10,893,403	377,428,163	37,923,959	11,159,910	15,115,732	64,199,601
	West	413,972,809	17,693,052	431,665,861	39,347,050	8,427,298	16,976,967	64,751,315
Difference	RTO	6,717,855	7,582,422	14,300,277	5,275,316	422,252	1,597,038	7,294,607
	East	(31,258)	1,130,380	1,099,122	(999,650)	1,363,827	1,647,143	2,011,321
	West	6,749,114	6,452,042	13,201,156	7,579,301	(761,546)	(50,105)	6,767,650

Deviations fall into three categories, demand, supply and generator deviations. Table 4-19 shows the different categories by the type of transactions that incurred deviations. In 2014, 21.1 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 78.9 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 4-19 Deviations by transaction type: 2014

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	336,247	191,938	144,309	0.3%	0.3%	0.2%
	DECs Only	11,419,063	3,862,100	6,676,624	8.8%	6.0%	10.3%
	Exports Only	5,582,178	3,352,015	2,230,162	4.3%	5.2%	3.4%
	Load Only	51,771,741	25,520,684	26,251,057	39.8%	39.8%	40.5%
	Combination with DECs	5,879,828	3,750,745	2,126,979	4.5%	5.8%	3.3%
	Combination without DECs	3,164,394	1,246,476	1,917,918	2.4%	1.9%	3.0%
Supply	Bilateral Purchases Only	379,403	251,854	127,549	0.3%	0.4%	0.2%
	Imports Only	9,255,098	6,326,946	2,928,152	7.1%	9.9%	4.5%
	INCs Only	7,616,994	3,100,646	4,112,276	5.8%	4.8%	6.4%
	Combination with INCs	2,628,596	1,382,335	1,246,261	2.0%	2.2%	1.9%
	Combination without INCs	111,189	98,130	13,059	0.1%	0.2%	0.0%
Generators		32,092,699	15,115,732	16,976,967	24.6%	23.5%	26.2%
Total		130,237,430	64,199,601	64,751,315	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-20 shows the totals for each credit category in 2013 and 2014. During 2014, 82.0 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 36.6 percentage points from 45.3 percent in 2013.

Table 4-20 Energy uplift credits by category: 2013 and 2014

Category	Type	2013 Credits (Millions)	2014 Credits (Millions)	Change	Percent Change	2013 Share	2014 Share
Day-Ahead	Generators	$64.1	$111.4	$47.3	73.9%	7.6%	11.5%
	Imports	$0.0	$0.0	($0.0)	(74.0%)	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	(85.9%)	0.0%	0.0%
Balancing	Canceled Resources	$0.5	$1.3	$0.9	195.2%	0.1%	0.1%
	Generators	$295.0	$627.3	$332.3	112.7%	34.9%	65.0%
	Imports	$0.0	$0.1	$0.1	173.7%	0.0%	0.0%
	Load Response	$0.7	$0.0	($0.7)	(95.7%)	0.1%	0.0%
	Local Constraints Control	$0.1	$1.9	$1.8	1,295.0%	0.0%	0.2%
	Lost Opportunity Cost	$87.3	$160.1	$72.8	83.4%	10.3%	16.6%
Reactive Services	Day-Ahead	$291.8	$24.9	($266.9)	(91.5%)	34.5%	2.6%
	Local Constraints Control	$0.1	$0.0	($0.1)	(61.8%)	0.0%	0.0%
	Lost Opportunity Cost	$0.5	$0.2	($0.3)	(55.1%)	0.1%	0.0%
	Reactive Services	$18.7	$3.4	($15.3)	(81.9%)	2.2%	0.4%
	Synchronous Condensing	$0.4	$0.9	$0.5	114.7%	0.0%	0.1%
Synchronous Condensing		$0.4	$0.1	($0.3)	(73.8%)	0.0%	0.0%
Black Start Services	Day-Ahead	$84.1	$27.5	($56.6)	(67.3%)	9.9%	2.8%
	Balancing	$2.2	$5.2	$2.9	132.5%	0.3%	0.5%
	Testing	$0.4	$0.4	($0.0)	(2.2%)	0.0%	0.0%
Total		$846.2	$964.7	$118.5	14.0%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-21 shows the distribution of total energy uplift credits by unit type in 2013 and 2014. The increase in energy uplift in 2014 compared to 2013 was due to credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal). Credits to these units increased $385.3 million or 100.5 percent mainly because these units' offers were impacted by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $266.2 million.

Table 4-21 Energy uplift credits by unit type: 2013 and 2014

Unit Type	2013 Credits (Millions)	2014 Credits (Millions)	Change	Percent Change	2013 Share	2014 Share
Combined Cycle	$192.0	$399.1	$207.0	107.8%	22.7%	41.4%
Combustion Turbine	$148.8	$260.4	$111.6	75.0%	17.6%	27.0%
Diesel	$6.5	$3.1	($3.4)	(51.8%)	0.8%	0.3%
Hydro	$0.7	$1.6	$1.0	145.2%	0.1%	0.2%
Nuclear	$0.1	$0.3	$0.1	87.1%	0.0%	0.0%
Solar	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Steam - Coal	$443.8	$182.7	($261.0)	(58.8%)	52.5%	18.9%
Steam - Other	$42.5	$109.2	$66.6	156.7%	5.0%	11.3%
Wind	$10.9	$8.1	($2.8)	(25.6%)	1.3%	0.8%
Total	$845.4	$964.6	$119.1	14.1%	100.0%	100.0%

Table 4-22 shows the distribution of energy uplift credits by category and by unit type in 2014. Combined cycle units received 32.9 percent of the day-ahead generator credits in 2014, 16.6 percentage points lower than the share received in 2013. Combined cycle units received 56.2 percent of the balancing generator credits in 2014, 9.2 percentage points higher than the share received in 2013. Combustion turbines and diesels received 69.8 percent of the lost opportunity cost credits in 2014, 2.4 percentage points lower than the share received in 2013.

Table 4-22 Energy uplift credits by unit type: 2014

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	32.9%	56.2%	0.0%	1.1%	5.3%	5.0%	0.0%	0.0%
Combustion Turbine	14.6%	20.6%	0.5%	52.8%	69.1%	9.4%	99.9%	1.1%
Diesel	0.1%	0.3%	0.0%	1.2%	0.7%	0.7%	0.0%	0.0%
Hydro	0.3%	0.0%	98.5%	0.0%	0.0%	0.0%	0.1%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	49.6%	6.1%	1.0%	42.5%	19.6%	83.7%	0.0%	98.9%
Steam - Others	2.6%	16.8%	0.0%	0.2%	0.2%	1.2%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	2.2%	5.0%	0.0%	0.0%	0.0%
Total (Millions)	$111.4	$627.3	$1.3	$1.9	$160.1	$29.4	$0.1	$33.0

Table 4-22 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In 2014, coal units received 83.7 percent of all reactive services credits, 2.8 percentage points lower than the share received in 2013. Coal units received 98.9 percent of all black start services credits.

Concentration of Energy Uplift Credits

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

The concentration of energy uplift credits is first examined by analyzing the characteristics of the top 10 units, top 50 and top 100 units receiving energy uplift credits and units receiving 90 percent of all energy uplift credits. Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 33.6 percent of total energy uplift credits in 2014, compared to 37.3 percent in 2013. In 2014, 228 units received 90 percent of all energy uplift credits, compared to 153 units in 2013.

Figure 4-6 Cumulative share of energy uplift credits in 2013 and 2014 by unit

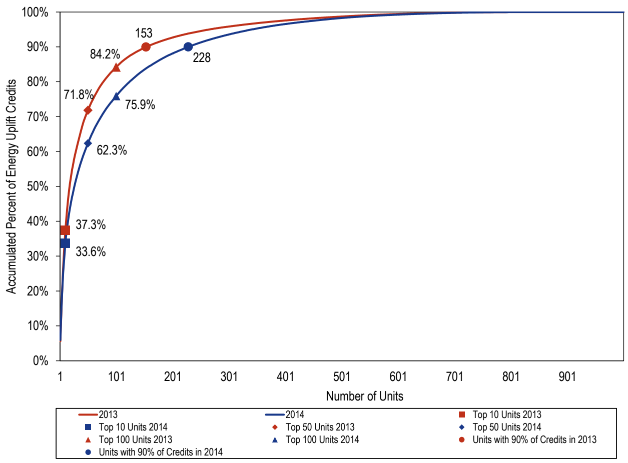


Table 4-23 shows the historical share of energy uplift credits paid to the top 10 units.

Table 4-23 Top 10 energy uplift credits units (By percent of total system): 2001 through 2014

	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	37.3%	0.7%
2014	33.6%	0.7%

Table 4-24 Top 10 units and organizations energy uplift credits: 2014

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$63.6	57.1%	$99.0	88.9%
Balancing	Canceled Resources	$1.3	100.0%	$1.3	100.0%
	Generators	$302.0	48.1%	$548.2	87.4%
	Local Constraints Control	$1.5	80.5%	$1.9	99.4%
	Lost Opportunity Cost	$32.1	20.0%	$120.6	75.3%
Reactive Services		$22.3	75.8%	$29.0	98.4%
Synchronous Condensing		$0.1	90.8%	$0.1	100.0%
Black Start Services		$29.8	90.2%	$33.0	100.0%
Total		$323.9	33.6%	$778.5	80.7%

Table 4-24 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-25 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2014, 14.9 percent of all credits paid to these units were allocated to deviations while the remaining 85.1 percent were paid for reliability reasons.

Table 4-25 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2014

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$257.1	$0.0	$0.0	$33.5	$11.4	$0.0	$302.0
Share	85.1%	0.0%	0.0%	11.1%	3.8%	0.0%	100.0%

In 2014, concentration in all energy uplift credit categories was high.[17,18] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-26 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 4682, for balancing operating reserve credits to generators was 3142, for lost opportunity cost credits was 4070 and for reactive services credits was 7315.

17 See *State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

18 Table 4-23 excludes local constraints control categories.

Table 4-26 Daily energy uplift credits HHI: 2014

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	4682	1080	10000	100.0%	30.6%
	Imports	10000	10000	10000	100.0%	92.9%
	Load Response	9920	9520	10000	100.0%	93.3%
Balancing	Canceled Resources	9348	6054	10000	100.0%	94.7%
	Generators	3142	793	9440	97.1%	24.1%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	59.4%
	Lost Opportunity Cost	4070	545	10000	100.0%	16.5%
Reactive Services		7315	2544	10000	100.0%	43.0%
Synchronous Condensing		10000	10000	10000	100.0%	51.2%
Black Start Services		6208	2906	10000	100.0%	98.9%
Total		1626	506	6725	81.7%	16.0%

Economic and Noneconomic Generation[19]

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 4-27 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 2014, 36.5 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 34.5 percent of the real-time generation was eligible for balancing operating reserve credits.[20]

Table 4-27 Day-ahead and real-time generation (GWh): 2014

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	828,682	302,489	36.5%
Real-Time	807,987	278,599	34.5%

Table 4-28 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In 2014, 87.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.9 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 4-28 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

19 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.

20 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 4-28 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2014

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	264,081	38,408	87.3%	12.7%
Real-Time	203,005	75,594	72.9%	27.1%

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 4-29 shows the generation receiving day-ahead and balancing operating reserve credits. In 2014, 6.7 percent of the day-ahead generation eligible for operating reserve credits received credits and 4.7 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-29 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2014

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	302,489	20,229	6.7%
Real-Time	278,599	12,968	4.7%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[21] 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.[22] Units scheduled as must run by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-30 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In 2014, 4.1 percent of the total day-ahead generation was scheduled as must run by PJM, 0.5 percentage points lower than in 2013.

Table 4-30 Day-ahead generation scheduled as must run by PJM (GWh): 2013 and 2014

	2013			2014		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	72,681	2,907	4.0%	81,479	2,627	3.2%
Feb	65,632	2,474	3.8%	70,942	3,404	4.8%
Mar	67,940	3,178	4.7%	72,681	2,894	4.0%
Apr	57,570	2,522	4.4%	60,688	2,825	4.7%
May	61,169	2,848	4.7%	61,919	2,808	4.5%
Jun	68,452	3,724	5.4%	70,230	3,421	4.9%
Jul	78,639	4,395	5.6%	75,606	3,733	4.9%
Aug	73,783	3,678	5.0%	73,003	2,778	3.8%
Sep	64,757	3,162	4.9%	65,066	2,792	4.3%
Oct	62,134	2,940	4.7%	61,223	2,444	4.0%
Nov	63,827	2,675	4.2%	64,991	1,857	2.9%
Dec	73,112	2,612	3.6%	70,853	2,023	2.9%
Total	809,695	37,115	4.6%	828,682	33,608	4.1%

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

Table 4-31 shows the total day-ahead generation scheduled as must run by PJM by category. In 2014, 35.5 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 9.8 percent was generation from units scheduled to provide black start services, 5.3 percent was generation from units scheduled to provide reactive services and 20.4 percent was generation paid normal day-ahead operating reserve credits. The remaining 64.5 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

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

22 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version January 9, 2015) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-31 Day-ahead generation scheduled as must run by PJM by category (GWh): 2014

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	216	157	232	2,022	2,627
Feb	84	30	428	2,862	3,404
Mar	242	162	325	2,166	2,894
Apr	333	243	442	1,807	2,825
May	235	238	564	1,772	2,808
Jun	251	328	506	2,336	3,421
Jul	374	241	685	2,434	3,733
Aug	395	54	760	1,569	2,778
Sep	404	54	805	1,530	2,792
Oct	306	140	801	1,197	2,444
Nov	194	44	468	1,151	1,857
Dec	266	79	855	822	2,023
Total	3,299	1,771	6,871	21,667	33,608
Share	9.8%	5.3%	20.4%	64.5%	100.0%

Total day-ahead operating reserve credits in 2014 were $111.4 million, of which $60.7 million or 54.5 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify and classify all reasons for paying operating reserve credits in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to inform all market participants of the reason for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.[23] The overall goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Geography of Charges and Credits

Table 4-32 shows the geography of charges and credits in 2014. Table 4-32 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.2 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 0.7 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 4.6 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 13.8 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had a 22.1 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-32 also shows that 90.6 percent of all charges were allocated in control zones, 2.2 percent in hubs and aggregates and 7.2 percent in interfaces.

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

Table 4-32 Geography of regional charges and credits: 2014[24]

Location		Charges (Millions)	Credits (Millions)	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$11.0	$8.2	($2.8)	1.2%	0.9%	0.7%	0.0%
	AEP - EKPC	$153.6	$41.8	($111.7)	17.1%	4.6%	29.6%	0.0%
	AP - DLCO	$64.1	$27.5	($36.7)	7.1%	3.1%	9.7%	0.0%
	ATSI	$62.8	$20.8	($42.1)	7.0%	2.3%	11.1%	0.0%
	BGE - Pepco	$70.3	$85.4	$15.1	7.8%	9.5%	0.0%	4.0%
	ComEd - External	$92.7	$40.4	($52.3)	10.3%	4.5%	13.8%	0.0%
	DAY - DEOK	$49.9	$3.6	($46.2)	5.5%	0.4%	12.2%	0.0%
	Dominion	$93.7	$131.2	$37.5	10.4%	14.6%	0.0%	9.9%
	DPL	$22.8	$52.7	$29.9	2.5%	5.9%	0.0%	7.9%
	JCPL	$22.6	$67.7	$45.1	2.5%	7.5%	0.0%	11.9%
	Met-Ed	$17.9	$63.2	$45.3	2.0%	7.0%	0.0%	12.0%
	PECO	$41.5	$90.9	$49.4	4.6%	10.1%	0.0%	13.1%
	PENELEC	$23.5	$25.6	$2.1	2.6%	2.8%	0.0%	0.6%
	PPL	$46.8	$116.7	$69.9	5.2%	13.0%	0.0%	18.5%
	PSEG	$41.0	$124.5	$83.5	4.6%	13.8%	0.0%	22.1%
	RECO	$1.4	$0.0	($1.4)	0.2%	0.0%	0.4%	0.0%
	All Zones	$815.4	$900.1	$84.7	90.6%	100.0%	77.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$7.2	$0.0	($7.2)	0.8%	0.0%	1.9%	0.0%
	Dominion	$1.6	$0.0	($1.6)	0.2%	0.0%	0.4%	0.0%
	Eastern	$0.3	$0.0	($0.3)	0.0%	0.0%	0.1%	0.0%
	New Jersey	$0.7	$0.0	($0.7)	0.1%	0.0%	0.2%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$0.5	$0.0	($0.5)	0.1%	0.0%	0.1%	0.0%
	Western	$9.2	$0.0	($9.2)	1.0%	0.0%	2.4%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$19.6	$0.0	($19.6)	2.2%	0.0%	5.2%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$1.7	$0.0	($1.7)	0.2%	0.0%	0.4%	0.0%
	IMO	$6.6	$0.0	($6.6)	0.7%	0.0%	1.8%	0.0%
	Linden	$1.5	$0.0	($1.5)	0.2%	0.0%	0.4%	0.0%
	MISO	$14.3	$0.0	($14.3)	1.6%	0.0%	3.8%	0.0%
	Neptune	$3.1	$0.0	($3.1)	0.3%	0.0%	0.8%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.0%	0.0%	0.0%	0.0%
	NYIS	$11.0	$0.0	($11.0)	1.2%	0.0%	2.9%	0.0%
	OVEC	$3.7	$0.0	($3.7)	0.4%	0.0%	1.0%	0.0%
	South Exp	$4.8	$0.0	($4.8)	0.5%	0.0%	1.3%	0.0%
	South Imp	$18.4	$0.0	($18.4)	2.0%	0.0%	4.9%	0.0%
	All Interfaces	$65.3	$0.1	($65.2)	7.3%	0.0%	17.3%	0.0%
	Total	$900.0	$900.0	$0.0	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 4-33 shows the geography of reactive services charges. In 2014, 97.0 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 0.2 percent were paid by real-time load in multiple zones and 2.8 percent were paid by real-time load across the entire RTO. In 2014, the top three zones accounted for 80.1 percent of all the reactive services charges allocated to single zones.

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

Table 4-33 Geography of reactive services charges: 2014[25]

Location	Charges (Millions)	Share of Charges
Single Zone	$28.5	97.0%
Multiple Zones	$0.1	0.2%
Entire RTO	$0.8	2.8%
Total	$29.4	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 98.9 percent of all the black start services costs in 2014. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in four control zones accounted for all synchronous condensing costs in 2014.

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[26] 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 2014, LOC credits increased by $72.8 million or 83.4 percent compared to 2013. The increase of $72.8 million is comprised of an increase of $48.7 million in day-ahead LOC and an increase of $24.1 million in real-time LOC. Table 4-34 shows the monthly composition of LOC credits in 2013 and 2014. The increase in LOC credits was primarily a result of higher real-time energy prices in January during hours for which the units had been scheduled day ahead and should have been called in real time but were not and units that were manually dispatched down in order to maintain system reliability during periods of high energy prices. Lost opportunity cost credits increased by $66.0 in January 2014, compared to January 2013. The impact of high real-time energy prices was partially offset by less generation receiving LOC credits in 2014 compared to 2013. In 2014, 23.7 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 7.0 percentage points lower than in 2013.

Table 4-34 Monthly lost opportunity cost credits (Millions): 2013 and 2014

	2013			2014		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$8.7	$2.8	$11.5	$47.6	$29.9	$77.5
Feb	$2.0	$2.7	$4.7	$6.0	$5.4	$11.5
Mar	$4.8	$2.3	$7.1	$8.8	$4.1	$12.8
Apr	$3.9	$1.9	$5.8	$1.6	$1.4	$3.0
May	$5.3	$3.3	$8.5	$10.5	$2.5	$13.0
Jun	$6.2	$0.8	$7.0	$7.2	$1.2	$8.4
Jul	$16.3	$3.2	$19.5	$6.3	$0.3	$6.5
Aug	$5.4	$0.2	$5.7	$5.2	$0.1	$5.3
Sep	$6.4	$4.8	$11.1	$5.3	$0.7	$6.0
Oct	$2.5	$0.6	$3.1	$5.6	$1.5	$7.1
Nov	$1.4	$0.8	$2.1	$4.0	$0.7	$4.7
Dec	$0.5	$0.6	$1.1	$4.1	$0.2	$4.3
Total	$63.4	$23.9	$87.3	$112.1	$48.0	$160.1
Share	72.6%	27.4%	100.0%	70.0%	30.0%	100.0%

Table 4-35 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. Table 4-35 shows that while day-ahead scheduled generation from CTs and diesels increased 1,628 GWh or 12.5 percent in 2014 compared to 2013, the generation that received LOC credits was reduced by 525 GWh or 13.1 percent.

25 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 11 (May 29, 2014).

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

Table 4-35 Day-ahead generation from combustion turbines and diesels (GWh): 2013 and 2014

	2013			2014		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	886	633	561	2,150	846	358
Feb	430	206	173	763	304	153
Mar	809	395	282	976	234	126
Apr	684	325	256	438	170	47
May	1,032	387	260	1,206	617	387
Jun	1,284	696	440	1,363	559	357
Jul	2,951	947	748	1,657	534	370
Aug	1,772	778	544	1,791	637	453
Sep	1,219	480	295	1,550	536	396
Oct	929	451	267	1,380	573	427
Nov	578	213	120	683	285	134
Dec	426	109	49	671	342	259
Total	13,001	5,620	3,994	14,628	5,636	3,469
Share	100.0%	43.2%	30.7%	100.0%	38.5%	23.7%

In 2014, the top three control zones in which generation received LOC credits, AEP, Dominion and PENELEC, accounted for 53.2 percent of all LOC credits, 47.3 percent of all the day-ahead generation from combustion turbines and diesels, 56.2 percent of all day-ahead generation not committed in real time by PJM from those unit types and 66.4 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled day ahead to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for LOC credits for hours 10, 11, 17 and 18. Table 4-36 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 4-36 shows that in 2014, $62.2 million or 55.5 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 10.8 percentage points lower than 2013.

Table 4-36 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2013 and 2014

	2013			2014		
	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total
Jan	$8.1	$0.6	$8.7	$21.1	$26.4	$47.6
Feb	$1.9	$0.2	$2.0	$3.7	$2.4	$6.0
Mar	$3.0	$1.8	$4.8	$3.6	$5.2	$8.8
Apr	$2.5	$1.4	$3.9	$0.8	$0.8	$1.6
May	$3.6	$1.7	$5.3	$8.3	$2.2	$10.5
Jun	$4.8	$1.4	$6.2	$5.4	$1.8	$7.2
Jul	$7.5	$8.8	$16.3	$3.8	$2.5	$6.3
Aug	$3.4	$2.1	$5.4	$3.7	$1.6	$5.2
Sep	$4.2	$2.2	$6.4	$3.0	$2.2	$5.3
Oct	$2.2	$0.3	$2.5	$3.3	$2.3	$5.6
Nov	$0.8	$0.5	$1.4	$2.9	$1.1	$4.0
Dec	$0.2	$0.3	$0.5	$2.6	$1.5	$4.1
Total	$42.0	$21.4	$63.4	$62.2	$49.9	$112.1
Share	66.3%	33.7%	100.0%	55.5%	44.5%	100.0%

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-37 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 4-37 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2014, 58.6 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 41.4 percent was noneconomic.

Table 4-37 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2013 and 2014[27]

	2013			2014		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	544	121	664	365	359	725
Feb	171	53	224	134	159	293
Mar	269	144	413	128	105	233
Apr	225	93	318	66	114	180
May	228	129	357	374	198	572
Jun	364	272	635	336	168	504
Jul	713	202	915	334	145	480
Aug	436	275	711	336	281	617
Sep	293	166	459	332	192	524
Oct	256	175	431	355	208	564
Nov	131	64	195	97	160	257
Dec	35	59	94	234	96	330
Total	3,665	1,753	5,418	3,092	2,186	5,278
Share	67.6%	32.4%	100.0%	58.6%	41.4%	100.0%

Black Start Service Units

Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the automatic load rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option can remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[28]

In 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone decreased by $53.7 million compared to 2013. In 2014, the cost of the noneconomic operation of these units was $32.6 million, and 94.4 percent of these costs was paid by peak transmission use in the AEP Control Zone while the remaining 5.6 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP Control Zone. Load in the AEP Control Zone paid an average of $3.70 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.02 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP Control Zone. PJM awarded all viable solutions from the last RFP.[29] PJM also approved new rules concerning black start service procurement. Resources selected through the new process are expected to provide black start service as of April 1, 2015.[30,31]

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. PJM also plans to use closed loop interfaces to set the real-time LMP with emergency DR resources and PJM has done so. These closed loop interfaces would be used

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

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

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

30 See the *2014 State of the Market Report for PJM*, Volume II, Section 10, "Ancillary Services" at "Black Start Service".

31 See PJM. Manual 14D: Generator Operational Requirement, Revision 33 (February 5, 2015) at "Section 10: Black Start Generation Procurement."

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. Table 4-38 shows the closed loop interfaces that PJM has defined.

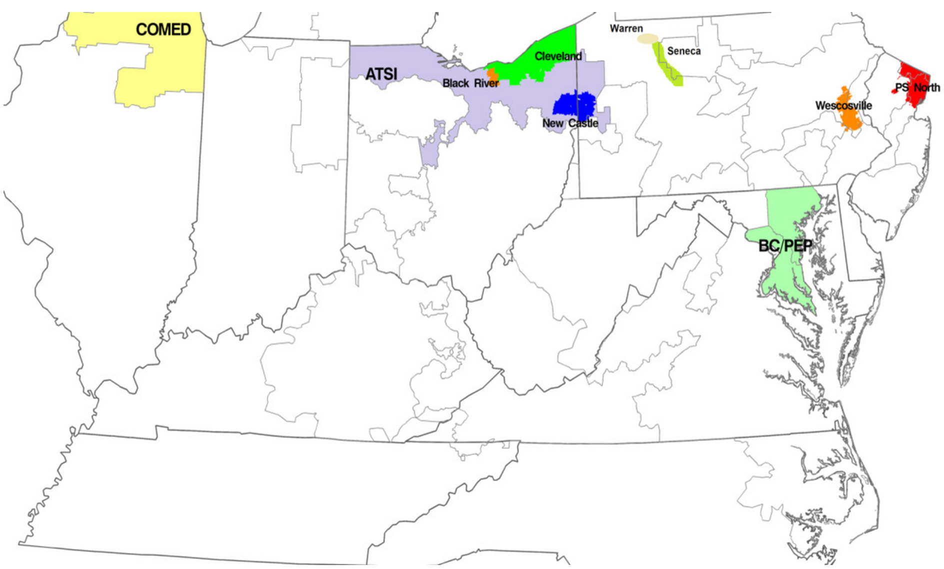
not needed for energy, by adjusting the limit of the closed loop interface. This would create congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by making these units marginal to the extent possible, hence reducing energy uplift costs.[35]

Table 4-38 PJM Closed Loop Interfaces[32,33,34]

Interface	Control Zone(s)	Objective
ATSI	ATSI	Allow emergency DR resources set real-time LMP
BC/PEPCO	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area
Black River	ATSI	Allow emergency DR resources set real-time LMP
Cleveland	ATSI	Reactive Interface (IROL)
ComEd	ComEd	Reactive Interface (IROL)
New Castle	ATSI	Allow emergency DR resources set real-time LMP
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP
Wescosville	PPL	Allow emergency DR resources set real-time LMP

Figure 4-7 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-7 PJM Closed Loop Interfaces Map



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

32 See PJM. Manual 3: Transmission Operations, Revision 46 (December 1, 2014) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.

33 See the ATSI, Black River, New Castle, Seneca, Warren and Wescosville interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.

34 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

35 See "PJM Price-Setting Changes" at <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx>

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 not use closed loop interfaces to set zonal prices, rather than use nodal prices, to accommodate the inadequacies of the demand side resource capacity product or the inability of the LMP model to fully accommodate reactive issues. Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals.

The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that closed loop interfaces be implemented only after such analysis, only after significant advance notice to the markets and only if the result is consistent with energy market fundamentals.

AP South / Bedington – Black Oak Reactive Support

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

On December 24, 2013, PJM began to schedule less generation from these units in order to reduce energy uplift costs associated with the reactive support to the 500 kV transmission lines that comprise the AP South and Bedington – Black Oak reactive transfer interfaces.[36] These units reduced their FMU adders, which reduced the level of payments.[37] At the same time, PJM began again to model the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy Markets. These actions reduced energy uplift costs for the noneconomic operation of units and, in combination with the system conditions of the last nine months of 2014, shifted most of the energy uplift costs from the reactive services category to the day-ahead operating reserve category.

In the last nine months of 2014, PJM reduced the commitment of units from the set of units in the BGE and Pepco control zones previously selected to provide reactive support. In the last nine months of 2014, PJM committed an average of 6.4 units compared to 7.6 units in the last nine months of 2013.

In 2014, energy uplift credits paid to these units decreased 69.4 percent compared to the amount paid in 2013, including a decrease of 99.7 percent in reactive service related uplift, offset by an increase of 88.0 percent of day-ahead and balancing operating reserve credits not allocated as reactive. These units were more economic in 2014, primarily as a result of higher LMPs in the first three months of 2014.[38] Reduced FMU adders for these reactive units also significantly reduced the offers and energy uplift credits of these units. The more efficient commitment of these units and the market conditions in 2014 shifted the allocation of the uplift costs associated with these units from reactive services to day ahead operating reserves.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Current confidentiality rules do not allow posting data for three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[39]

Energy uplift charges are out of market, non-transparent payments made to resources operating at PJM's direction. Energy uplift charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons

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

37 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.

38 See *State of the Market Report for PJM*, Volume II: Section 3, "Energy Market" at "Prices" for the components of the day-ahead and real-time LMP and their contribution in 2013 and 2014.

39 See OA. "Manual 33: Administrative Services for the PJM Interconnection Operating Agreement," Revision 11 (May 29, 2014), Market Data Posting.

and locations of these payments, making it difficult for other participants to compete with the resources receiving energy uplift payments. Uplift charges are not included in the transmission planning process meaning that transmission solutions are not considered. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and the absence of relevant information creates a barrier to entry. The MMU recommends that PJM revise the current energy uplift confidentiality rules in order to allow the disclosure of energy uplift credits by zone, by owner and by resource.

Energy Uplift Recommendations

Credits Recommendations

Day-Ahead Operating Reserve Elimination

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

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[40]

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

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

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine

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

if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units the MMU recommended enhancing the day-ahead operating reserve credits calculation to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[41] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[42] The elimination of the day-ahead operating reserve category also ensures that units are always made whole based on their actual operation and actual revenues. The MMU supports the PJM proposal of eliminating the day-ahead operating reserve category.

The MMU calculated the impact of this recommendation in 2013 and 2014. In 2013 and 2014, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $100.2 million or 14.0 percent ($10.7 million paid to units providing reactive support, $16.2 million paid to units providing black start support and $73.3 million paid to units as day-ahead and balancing operating reserves).

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

Net Regulation Revenues Offset

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

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

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

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2013 and 2014, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $24.4 million, of which $19.6 million or 80.4 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.[43]

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

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

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

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[44] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled are price takers in both the Day-Ahead and Real-Time Energy Markets unless self-scheduled units elect to submit a fixed energy amount per hour or a minimum must run amount from which the unit may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

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

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommends four modifications.[45]

- **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 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.

44 See "PJM eMkt Users Guide," Section Managing Unit Data (version January 9, 2015) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

45 See "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>.

- **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 lost opportunity cost 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.
- **Segmented Calculation:** Current rules calculate LOC on an hourly basis. This means that units receive an LOC payment during hours in which it is economic for them run and receive the benefit of not being called on during hours in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment. This is not the intent of LOC payments. LOC should be paid to resources to

ensure that they operate following PJM's direction and not lose their profit. In the case of hourly calculations, units are not made indifferent, but are overcompensated compared to the compensation they would have received had they run. The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

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 4-39 shows the impact that each of these changes would have had on the LOC credits in the Energy Market in 2014, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $37.2 million, or 23.3 percent, if all these changes had been implemented.[46]

Table 4-39 Impact on energy market lost opportunity cost credits of rule changes (Millions): 2014

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$48.0	$112.1	$160.1
Impact 1: Committed Schedule	$1.5	$11.6	$13.0
Impact 2: Using Offer Curve	($1.5)	$7.4	$5.9
Impact 3: Including No Load Cost	NA	($29.7)	($29.7)
Impact 4: Including Startup Cost	NA	($10.6)	($10.6)
Impact 5: Segmented Calculation	NA	($15.9)	($15.9)
Net Impact	($0.0)	($37.2)	($37.2)
Credits After Changes	$47.9	$74.9	$122.9

Allocation Recommendations

Up-to Congestion Transactions

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

The MMU calculated the impact on energy uplift rates if up-to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do along with other recommendations that impact the total costs of energy uplift and its allocation.

The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. Up-to congestion transactions would have paid an average rate between $0.208 and $0.961 per MWh in 2013 and between $0.369 and $0.446 per MWh in 2014 if the MMU's recommendations regarding energy uplift had been in place.[47,48]

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.[49] 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

46 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.

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

48 This analysis assumes that not all costs associated with units providing support to the Con Edison – PJM Transmission Service Agreements would be reallocated under the MMU's proposal. The *2013 State of the Market Report for PJM* analysis assumed that all such costs would be reallocated. This analysis also assumes that only 50 percent of all cleared up-to congestion transactions would have cleared had this recommendation been in place prior September 8, 2014 and all cleared up-to congestion transactions would have cleared after September 8, 2014. The *2013 State of the Market Report for PJM* analysis showed that more than 66.7 percent of up-to congestion transactions would have remained under the MMU proposal.

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

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.[50] 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.

Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[51] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels.

Con Edison – PJM Transmission Service Agreements Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts.[52] 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 Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[53] 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

50 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" in this section for a description of balancing operating reserve locations.

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

52 See the *2014 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.

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

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 2014, units providing reactive services were paid $2.2 million in balancing operating reserve credits in order to cover their total energy offer. In 2013, this misallocation was $7.2 million, for a total of $9.4 million in the 2013 and 2014.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above. Currently, only real-time RTO load pays.[54]

Allocation Proposal

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

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

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time but before the operating day to the current deviation categories with the addition of up-to congestion, wheels and units that clear the Day-Ahead Scheduling Reserve Market but do not perform.

The MMU recommends the exclusion of offsets based on internal bilateral transactions. These costs should be allocated to the current deviation categories whenever the units receiving energy uplift payments are committed before the operating day.

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

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

54 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>.

commitment should be allocated to real-time load, real-time exports and real-time wheels independently of the timing of the commitment.

Table 4-40 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-40 Current energy uplift allocation

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

Table 4-41 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead transactions and resources. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-41 MMU energy uplift allocation proposal

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

Quantifiable Recommendations Impact

Table 4-42 shows energy uplift charges based on the current allocation and energy uplift charges based on the MMU allocation proposal including the MMU recommendations regarding energy uplift credit calculations. Total charges (excluding black start and reactive services charges) would have been reduced by $161.6 million or 12.0 percent in 2013 and 2014 if three recommendations regarding energy uplift credit calculations proposed by the MMU had been implemented. The elimination of the day-ahead operating reserve credit would have resulted in a decrease of $73.2 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $65.1 million and the use of net regulation revenues offset would have resulted in a decrease of $23.3 million.[55] Table 4-42 shows that deviations charges would have been reduced by $402.8 million or 60.2 percent. The reason for this change is that, besides the reduction in the overall charges, under the MMU proposal, a subset of charges is reallocated to a new physical deviation category (based on the timing of the commitment of the resource being paid energy uplift) and another subset of charges is allocated to real-time load, real-time exports and real-time wheels (based on reliability actions).

Table 4-42 Current and proposed energy uplift charges by allocation (Millions): 2013 and 2014[56]

Allocation	2013	2014	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$64.0	$111.4	$175.4
Real-Time Load and Real-Time Exports	$55.8	$447.1	$502.9
Deviations	$327.0	$341.7	$668.7
Total	$446.8	$900.2	$1,347.0
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$23.4	$46.5	$69.9
Real-Time Load and Real-Time Exports	$84.6	$456.2	$540.8
Deviations	$154.7	$111.1	$265.9
Physical Deviations	$104.5	$204.3	$308.8
Total	$367.3	$818.1	$1,185.4
Impact			
Impact ($)	($79.5)	($82.1)	($161.6)
Impact (%)	(17.8%)	(9.1%)	(12.0%)

Table 4-43 Current and proposed average energy uplift rate by transaction: 2013 and 2014[57]

		2013			2014		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	3.286	0.480	1.121	2.295	0.223	0.698
	DEC	3.391	0.480	1.121	2.424	0.223	0.698
	DA Load	0.105	0.010	0.013	0.129	0.019	0.024
	RT Load	0.076	0.109	0.109	0.450	0.460	0.460
	Deviation	3.286	1.234	1.873	2.295	1.316	1.787
West	INC	1.653	0.104	0.343	2.089	0.184	0.584
	DEC	1.758	0.104	0.343	2.219	0.184	0.584
	DA Load	0.105	0.010	0.013	0.129	0.019	0.024
	RT Load	0.056	0.099	0.099	0.439	0.460	0.460
	Deviation	1.653	0.667	0.903	2.089	1.231	1.626
UTC	East to East	NA	0.961	2.242	NA	0.446	1.397
	West to West	NA	0.208	0.685	NA	0.369	1.168
	East to/from West	NA	0.585	1.464	NA	0.407	1.282

The MMU calculated the rates that participants would have paid in 2013 and 2014 if all the MMU's recommendations on energy uplift had been in place. These recommendations have been included in the analysis: day-ahead operating reserve elimination; net regulation revenues offset; implementation of the proposed changes to lost opportunity

55 The total impact of the elimination of the day-ahead operating reserve credit and the impact of net regulation revenues offset is greater because they also impact black start and reactive services charges.
56 These energy uplift charges do not include black start and reactive services charges.
57 The deviation transaction means load, interchange transactions, generators and DR deviations.

cost calculations; reallocation of operating reserve credits paid to units scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services); reallocation of operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements;; elimination of internal bilateral transactions from the deviations calculation; allocation of energy uplift charges to up-to congestion transactions and the MMU energy uplift allocation proposal.

Table 4-43 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2013 and 2014. Table 4-43 assumes two scenarios under the MMU proposal. The first scenario assumes that 50 percent of all up-to congestion transactions cleared volume would have remained prior to September 8, 2014 and all up-to congestion transactions cleared volume would have remained after September 8, 2104. The second scenario assumes zero volume of up-to congestion transactions in 2013 and 2014. Table 4-43 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.480 and $0.223 per MWh in the 2013 and 2014, under the first scenario, $2.911 and $2.201 per MWh less than the actual average rate paid. Up-to congestion transactions sourced in the Eastern Region and sinking in the Western Region would have paid an average rate of $0.585 and $0.407 per MWh in 2013 and 2014 under the first scenario. Table 4-43 shows the current and proposed averages energy uplift rates for all transactions.

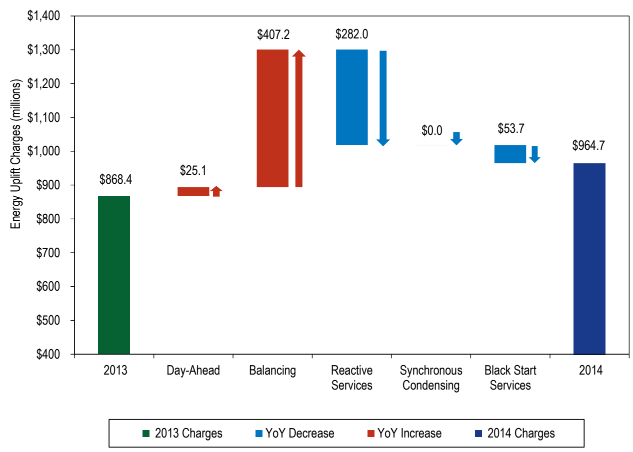
Year Over Year Energy Uplift Charges Analysis

Energy uplift charges increased by $96.3 million (11.1 percent), from $868.4 million in 2013 to $964.7 million in 2014. This increase was primarily the result of charges in the first three months of 2014. Energy uplift charges increased by $482.9 million (182.5 percent), from $264.5 million in the first three months of 2013 to $747.4 million in the first three months of 2014. Energy uplift charges decreased by $386.6 million (64.0 percent), from $603.9 million in the last nine months of 2013 to $217.3 million in the last nine months of 2014.

The energy uplift charges increase of $96.3 million in 2014 compared to 2013 resulted from an increase of $25.1 million in day-ahead operating reserve charges and an increase of $407.2 million in balancing operating reserve charges. These increases were partially offset by a decrease of $282.0 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $53.7 in black start services charges.

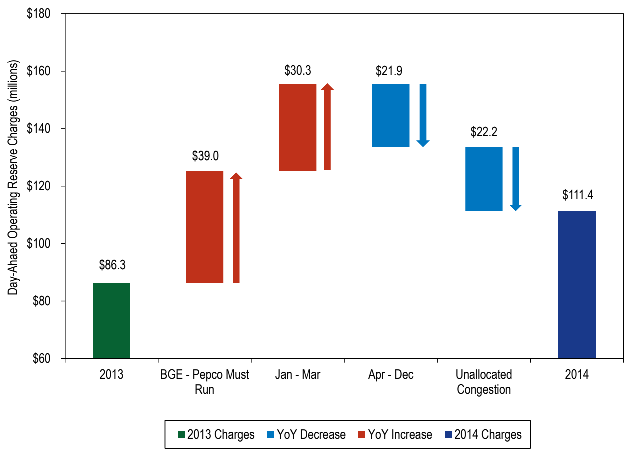
Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the 2013 level to 2014 level. The outside bars show the 2013 total energy uplift charges (left side) and the 2014 total energy uplift charges (right side). The other bars show the change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in 2014 compared to 2013 (an increase of $25.1 million).

Figure 4-8 Energy uplift charges change from 2013 to 2014 by category



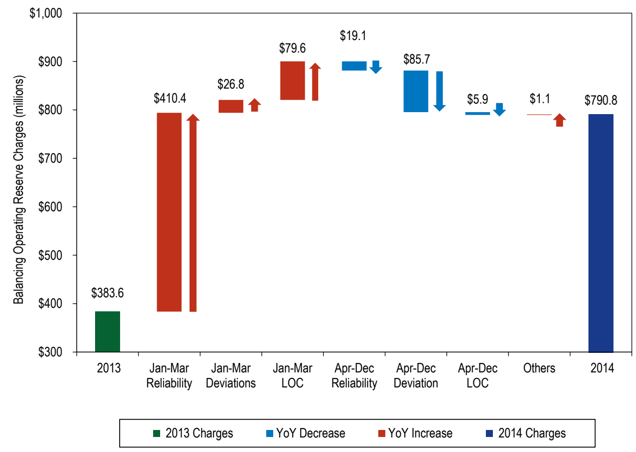
The increase in day-ahead operating reserve charges was mainly a result of the change in scheduling/commitment of a set of units in the BGE and Pepco control zones that provided reactive support to the 500 kV transmission system. In 2014, day-ahead operating reserve charges increased by $39.0 million because of this change compared to 2013. The increase of $30.3 million in day-ahead operating reserve charges in the first three months of 2014 compared to the first three months of 2013 was partially offset by the decrease of $21.9 million during the last nine months of 2014 compared to the last nine months of 2013. These changes exclude day-ahead operating reserve charges associated with the reactive units in BGE and Pepco. Finally, in 2014 there was zero negative balancing congestion allocated to day-ahead operating reserve charges compared to $22.2 million in 2013. Figure 4-9 shows the net change in day-ahead operating reserve charges.

Figure 4-9 Day-ahead operating reserve charges change from 2013 to 2014



The increase in balancing operating reserve charges was mainly a result of units committed for conservative operations during the first three months of 2014 compared to the first three months of 2013. These units had offers significantly higher than the LMP, primarily as a result of high natural gas prices and their inflexible operating parameters. Energy uplift costs associated with reliability increased by $410.4 million in the first three months of 2014 compared to the first three months of 2013. Energy uplift costs as a result of lost opportunity cost payments increased by $79.6 million in the first three months of 2014 compared to the first three months of 2013. Figure 4-10 shows the net change in balancing operating reserve charges.

Figure 4-10 Balancing operating reserve charges change from 2013 to 2014



The decrease in reactive services charges had several contributing factors. These factors included the change in unit scheduling/commitment of a set of units in the BGE and Pepco control zones that provided reactive support to the 500 kV transmission system in 2013 and a set of units in the DPL Control Zone that provided local reactive support, the reduction of FMU adders to all units providing reactive support, high energy prices in the first three months of 2014 compared to the first three months of 2013 and higher energy prices due to the use of closed loop interfaces in the PENELEC Control Zone. Figure 4-11 shows the net change in reactive services charges by allocation. The main contributing factor to the reduction of reactive services charges in 2014 was the reduction in the charges allocated across the entire RTO. In 2013, the cost of reactive service support to the 500 kV transmission system was allocated to all real-time load across the entire RTO.[58]

58 See "AP South / Bedington – Black Oak Reactive Support" in this section for further explanation of the change in scheduling/commitment and energy uplift payments to a set of units in the BGE and Pepco control zones.

Figure 4-11 Reactive services charges change from 2013 to 2014

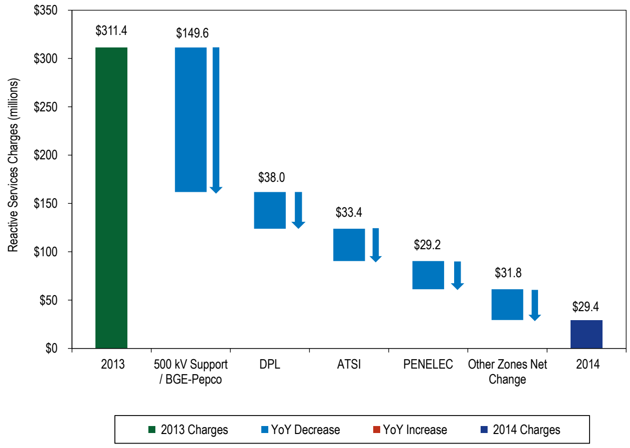
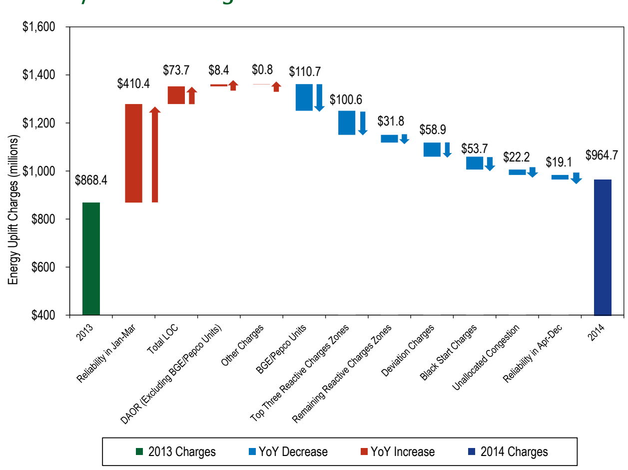


Figure 4-12 shows the contributions of multiple factors to the change in total energy uplift charges from 2013 to 2014. The increase in balancing operating reserve charges for reliability in the first three months of the year had the largest positive impact while the change in energy uplift payments to a set of units in the BGE and Pepco control zones had the largest negative impact.

Figure 4-12 Energy uplift charges change from 2013 to 2014 by contributing factor



Energy Uplift and Conservative Operations

PJM dispatchers committed a substantial number of units for conservative operations during the high load days of January 2014. Balancing operating reserve charges increased by $418.8 million in January 2014 compared to January 2013. This increase was mainly due to payments to units committed for conservative operations before the operating day. In January 2014, $331.4 million was paid to these units, $325.6 million higher than the payments for the same reason in January 2013. This increase represented 77.7 percent of the January 2014 increase in balancing operating reserve charges.

Within January 2014, the increase in balancing operating reserve charges was concentrated in 10 days. These 10 days accounted for 97.4 percent of all payments to units committed for conservative operations before the operating day.[59]

During these 10 days, 14.7 units on average were committed during the reliability analysis (before the operating day) for conservative operations, the highest number of units was 27 on January 28. The average output of these units as a group was 3,748 MW, the highest average output of these units as a group was 6,603 MW on January 28.

The units committed for conservative operations in January 2014 were mainly located in the Eastern Region of PJM and had high energy offers as a result of high natural gas prices in the area. During the peak hours of January these units were needed either to meet load, to provide additional reserves or to reduce operational uncertainty in general. During the peak hours of these 10 days in January, the units that received make whole payments were noneconomic by an average of $285.90 per MWh and by an average of $428.95 per MWh during off peak hours.[60] PJM's decision to keep running these units even when they were substantially noneconomic included uncertainty as to whether the units would restart, uncertainty about the ability of the units to procure natural gas and the inflexibility of natural gas

59 The 10 days were January 8 and January 21 through January 29.

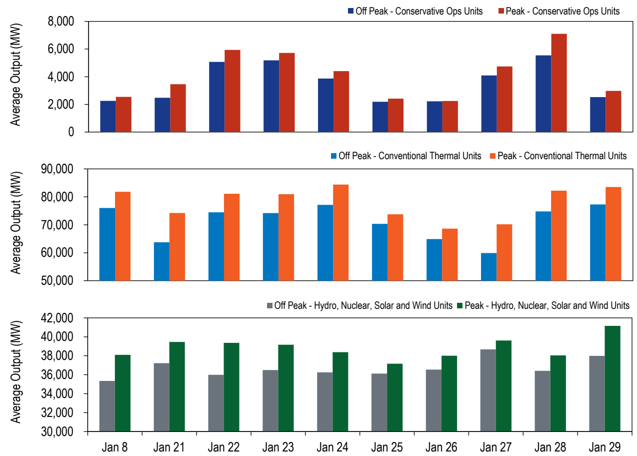
60 For the purposes of these analysis peak hours were defined as HE 8 through HE 11 and HE 18 through HE 21. The remaining 16 hours were defined as off peak hours.

procurement arrangements as asserted by unit operators to PJM dispatchers.

Figure 4-13 shows, for these 10 days in January, the average output in MW (on and off peak) from units committed for conservative operations and the average output in MW of other unit types. The figure shows (top figure) that on January 28, during peak hours, units committed for conservative operations produced 7,099 MW on average and reduced on average by only 1,554 MW to 5,545 MW during off peak hours, even though these units were noneconomic. The figure shows (middle figure) that on the same day, during peak hours, conventional thermal units (excluding hydro, nuclear, solar and wind and units committed for conservative operations) produced 82,219 MW on average, but were reduced on average by 7,442 MW to 74,776 MW during the off peak hours. The figure shows (bottom figure) that on the same day, during peak hours, hydro, nuclear, solar and wind units produced 38,043 MW on average and reduced on average by 1,636 MW to 36,408 MW during off peak hours. The sum of the average output in each bar in the top, middle and bottom figures equals the average output produced by units internal to PJM for each day during peak and off peak periods.

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

Figure 4-13 Peak and off peak output during high balancing operating reserve charges days



Lost Opportunity Cost Credits

In 2013, LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not committed in real time began to decrease as a result of less generation from this type of units being scheduled in day ahead in combination with PJM's implementation of a new tool to improve the commitment of combustion turbines (combustion turbine optimizer or CTO). In January 2014, the commitment of units in the Day-Ahead Energy Market for conservative operations even when these units did not clear the Day-Ahead Energy Market increased the amount of generation from combustion turbines and diesels scheduled in the Day-Ahead Energy Market that received lost opportunity cost credits. Figure 4-14 shows the average output of units committed by PJM before or during the operating day without having been scheduled in the Day-Ahead Energy Market and which were paid balancing operating reserve credits. Figure 4-14 also shows the average output of units scheduled in the Day-Ahead Energy Market from combustion turbines and diesels that were not committed in real time and were paid lost opportunity cost credits. The figure shows for example that on January 22, an average of 6,404 MW were committed by PJM in real time (without being scheduled in the Day-Ahead Energy Market) and paid balancing operating reserve credits while 2,810 MW scheduled in the Day-Ahead Energy Market were not committed in real time and paid lost opportunity cost credits.

Figure 4-14 BOR and LOC Generation: January 2014