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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $646.3 million, or 67.3 percent, in 2015 compared to 2014, from $960.5 million to $314.2 million.
- **Energy Uplift Charges Categories.** The decrease of $646.3 million in 2015 is comprised of a $12.6 million decrease in day-ahead operating reserve charges, a $587.0 million decrease in balancing operating reserve charges, an $18.8 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $27.7 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.050 per MWh, a DEC paid $1.187 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.072 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.042 per MWh, a DEC paid $1.151 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.036 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest local voltage support rates: $0.124, $0.056 and $0.027 per MWh. The reactive transfer interface support rate averaged $0.0019 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 24.0 percent of all day-ahead generator credits and 39.1 percent of all balancing generator credits. Combustion turbines and diesels received 85.6 percent of the lost opportunity cost credits. Coal units received 39.6 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 34.2 percent of all credits. The top 10 organizations received 78.0 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5828, balancing operating reserves HHI was 3740, lost opportunity cost HHI was 3788 and reactive services HHI was 9093.
- **Economic and Noneconomic Generation.** In 2015, 88.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2015, 1.9 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 44.0 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.

Geography of Charges and Credits

- In 2015, 88.4 percent of all uplift 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, 3.2 percent by transactions at hubs and aggregates and 8.3 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 68.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 31.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 0.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2015, lost opportunity cost credits decreased by $71.1 million compared to 2014. In 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and ComEd, accounted for 47.1 percent of all lost opportunity cost credits, 41.9 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 39.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 39.0 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 were relied on for their black start capability on a regular basis during periods when the units were not economic. These black start units provided black start service under the ALR option, which means that the units had to run in order to provide black start services even if the units were not economic. PJM replaced all ALR units as black start resources as of April 2015. In 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $27.8 million compared to 2014.
- **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 2015, the average rate paid by a DEC in the Eastern Region would have been $0.149 per MWh under the MMU proposal, which is $1.038 per MWh, or 87.4 percent, lower than the actual average rate paid.

Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. 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 2011. Status: Adopted 2014.)
- 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. Stakeholder process.)
- 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. Stakeholder process.)
- 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 2009. Status: Not adopted. Stakeholder process.)
- 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. Stakeholder process.)
- The MMU recommends seven modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - 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: Adopted 2015.)
  - 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: Adopted 2015.)
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2011. Status: Not adopted. Stakeholder process.)
- 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. Stakeholder process.)

- 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. First reported 2014. Status: Not adopted. Stakeholder process.)
- 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. Stakeholder process.)
- 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. Stakeholder process.)
- 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 solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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 Q2, 2012. Status: Not adopted. Stakeholder process.)

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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

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.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

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'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. 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. 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its price setting logic.

Energy Uplift

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

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

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

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

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

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $646.3 million or 67.3 percent in 2015 compared to 2014. Table 4-3 shows total energy uplift charges in 2001 through 2015.[2]

Table 4-3 Total energy uplift charges: 2001 through 2015

	Total Energy Uplift Charges (Millions)	Annual Change (Millions)	Annual Percent Change	Energy Uplift as a Percent of Total PJM Billing
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)	(31.9%)	1.2%
2010	$623.2	$300.4	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.9	$46.5	7.7%	2.2%
2013	$842.8	$192.9	29.7%	2.5%
2014	$960.5	$117.7	14.0%	1.9%
2015	$314.2	($646.3)	(67.3%)	0.9%

Table 4-4 compares energy uplift charges by category for 2014 and 2015. The decrease of $646.3 million in 2015 is comprised of a decrease of $12.6 million in day-ahead operating reserve charges, a decrease of $587.0 million in balancing operating reserve charges, a decrease of $18.8 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $27.7 million in black start services charges.

The decrease in total energy uplift charges was mainly a result of PJM not committing units for conservative operations in advance of the Day-Ahead Energy Market in the 2015 winter, compared to the 2014 winter. PJM still relied on some units committed for congestion in advance of the Day-Ahead Energy Market and during the reliability analysis after the Day-Ahead Energy Market closed, but the impact of these commitments on energy uplift in 2015 was significantly lower than in 2014.

2 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 25, 2016.

Table 4-4 Energy uplift charges by category: 2014 and 2015

Category	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$111.3	$98.7	($12.6)	(11.3%)
Balancing Operating Reserves	$786.7	$199.7	($587.0)	(74.6%)
Reactive Services	$29.5	$10.6	($18.8)	(64.0%)
Synchronous Condensing	$0.1	$0.0	($0.1)	(76.1%)
Black Start Services	$32.9	$5.2	($27.7)	(84.3%)
Total	$960.5	$314.2	($646.3)	(67.3%)

The decrease in energy uplift charges in 2015 was primarily a result of decreases from January 2014. Total energy uplift charges decreased by $561.3 million in January 2015, compared to January 2014, while energy uplift charges decreased by $85.0 million in February through December 2015, compared to February through December 2014. Table 4-5 compares monthly energy uplift charges by category for 2014 and 2015.

Table 4-5 Monthly energy uplift charges: 2014 and 2015

	2014 Charges (Millions)						2015 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$35.8	$562.4	$3.8	$0.1	$4.0	$606.1	$16.8	$24.5	$1.79	$0.0	$1.7	$44.8
Feb	$9.5	$56.0	$1.0	$0.0	$0.9	$67.4	$31.4	$71.0	$2.4	$0.0	$1.1	$105.9
Mar	$5.7	$59.1	$2.7	$0.0	$2.6	$70.1	$7.0	$24.7	$2.1	$0.0	$1.9	$35.8
Apr	$4.2	$9.7	$5.3	$0.0	$2.8	$22.0	$3.1	$8.5	$1.7	$0.0	$0.1	$13.4
May	$6.4	$21.0	$5.3	$0.0	$1.8	$34.5	$5.7	$15.5	$0.7	$0.0	$0.2	$22.1
Jun	$5.3	$15.8	$4.2	$0.0	$2.1	$27.3	$9.1	$8.9	$0.5	$0.0	$0.0	$18.5
Jul	$6.7	$11.4	$2.9	$0.0	$4.4	$25.4	$5.1	$12.3	$0.1	$0.0	$0.0	$17.5
Aug	$5.8	$9.9	$1.0	$0.0	$4.1	$20.8	$4.5	$9.1	$0.1	$0.0	$0.0	$13.6
Sep	$8.0	$12.5	$1.3	$0.0	$3.9	$25.6	$4.1	$9.0	$0.6	$0.0	$0.0	$13.7
Oct	$9.5	$9.8	$0.8	$0.0	$2.6	$22.8	$3.0	$5.5	$0.4	$0.0	$0.1	$9.0
Nov	$5.6	$10.1	$0.5	$0.0	$1.4	$17.6	$4.3	$6.4	$0.2	$0.0	$0.0	$10.9
Dec	$9.0	$9.0	$0.7	$0.0	$2.2	$20.9	$4.6	$4.3	$0.1	$0.0	$0.0	$8.9
Total	$111.3	$786.7	$29.5	$0.1	$32.9	$960.5	$98.7	$199.7	$10.6	$0.0	$5.2	$314.2
Share	11.6%	81.9%	3.1%	0.0%	3.4%	100.0%	31.4%	63.6%	3.4%	0.0%	1.6%	100.0%

Table 4-6 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges that pay 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.[3,4] Day-ahead operating reserve charges decreased by $12.6 million or 11.3 percent in 2015 compared to 2014. Day-ahead operating reserve charges remain high primarily because of uplift payments to units scheduled as must run by PJM. Units are typically scheduled as must run by PJM in the Day-Ahead Energy Market when the day-ahead model does not reflect certain real-time conditions or requirements (for example, reactive or ALR black start) or when units have parameters that extend beyond the 24 hour day-ahead model.

Table 4-6 Day-ahead operating reserve charges: 2014 and 2015

Type	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Day-Ahead Operating Reserve Charges	$111.3	$98.5	($12.8)	100.0%	99.8%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.2	$0.2	0.0%	0.2%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$111.3	$98.7	($12.6)	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $587.0 million in 2015 compared to 2014. This decrease was a result of lower balancing operating reserve charges in the 2015 winter compared to the 2014 winter. Balancing operating reserve charges decreased by $557.3 million in January, February and March of 2015 compared to January, February and March of 2014.

3 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.

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

Table 4-7 Balancing operating reserve charges: 2014 and 2015

Type	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Balancing Operating Reserve Reliability Charges	$447.1	$41.1	($405.9)	56.8%	20.6%
Balancing Operating Reserve Deviation Charges	$337.5	$157.5	($180.0)	42.9%	78.9%
Balancing Operating Reserve Charges for Load Response	$0.2	$0.2	($0.0)	0.0%	0.1%
Balancing Local Constraint Charges	$1.9	$0.9	($1.1)	0.2%	0.4%
Total	$786.7	$199.7	($587.0)	100.0%	100.0%

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In 2015, 46.1 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 7.3 percentage points compared to the share in 2014.

Table 4-8 Balancing operating reserve deviation charges: 2014 and 2015

Charge Attributable To	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Make Whole Payments to Generators and Imports	$180.3	$72.6	($107.7)	53.4%	46.1%
Energy Lost Opportunity Cost	$155.8	$84.8	($71.1)	46.2%	53.8%
Canceled Resources	$1.4	$0.2	($1.2)	0.4%	0.1%
Total	$337.5	$157.5	($180.0)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $18.8 million in 2015 compared to 2014. Black start services charges decreased by $27.7 million in 2015 compared to 2014 as a result of the replacement of black start units under the ALR (automatic load rejection) option in the second quarter of 2015.

Table 4-9 Additional energy uplift charges: 2014 and 2015

Type	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Reactive Services Charges	$29.5	$10.6	($18.8)	47.2%	67.1%
Synchronous Condensing Charges	$0.1	$0.0	($0.1)	0.2%	0.2%
Black Start Services Charges	$32.9	$5.2	($27.7)	52.7%	32.7%
Total	$62.5	$15.8	($46.7)	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in 2014 and 2015. 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 demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2015, regional balancing operating reserve charges decreased by $585.9 million compared to 2014. Balancing operating reserve reliability charges decreased by $405.9 million or 90.8 percent and balancing operating reserve deviation charges decreased by $180.0 million or 53.3 percent.

Table 4-10 Regional balancing charges allocation (Millions): 2014

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$429.2	54.7%	$6.7	0.9%	$3.3	0.4%	$439.2	56.0%
	Real-Time Exports	$7.5	1.0%	$0.2	0.0%	$0.1	0.0%	$7.8	1.0%
	Total	$436.7	55.7%	$7.0	0.9%	$3.4	0.4%	$447.1	57.0%
Deviation Charges	Demand	$170.7	21.8%	$12.4	1.6%	$4.8	0.6%	$187.9	23.9%
	Supply	$47.0	6.0%	$3.6	0.5%	$1.0	0.1%	$51.7	6.6%
	Generator	$90.5	11.5%	$5.2	0.7%	$2.3	0.3%	$98.0	12.5%
	Total	$308.3	39.3%	$21.2	2.7%	$8.1	1.0%	$337.5	43.0%
Total Regional Balancing Charges		$745.0	95.0%	$28.2	3.6%	$11.4	1.5%	$784.6	100%

Table 4-11 Regional balancing charges allocation (Millions): 2015

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$35.2	17.7%	$4.0	2.0%	$1.1	0.5%	$40.3	20.3%
	Real-Time Exports	$0.7	0.4%	$0.1	0.1%	$0.0	0.0%	$0.9	0.4%
	Total	$35.9	18.1%	$4.2	2.1%	$1.1	0.5%	$41.1	20.7%
Deviation Charges	Demand	$86.8	43.7%	$2.8	1.4%	$1.2	0.6%	$90.8	45.7%
	Supply	$25.6	12.9%	$0.9	0.4%	$0.4	0.2%	$26.9	13.5%
	Generator	$38.3	19.3%	$1.2	0.6%	$0.4	0.2%	$39.9	20.1%
	Total	$150.7	75.9%	$4.8	2.4%	$1.9	1.0%	$157.5	79.3%
Total Regional Balancing Charges		$186.7	94.0%	$9.0	4.5%	$3.0	1.5%	$198.7	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.[5]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2014 and 2015. The average rate in 2015 was $0.120 per MWh, $0.014 per MWh lower than the average in 2014. The highest rate in 2015 occurred on February 16, when the rate reached $1.600 per MWh, $0.088 per MWh lower than the $1.689 per MWh reached in 2014, on January 22. 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 and 2015.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2014 and 2015

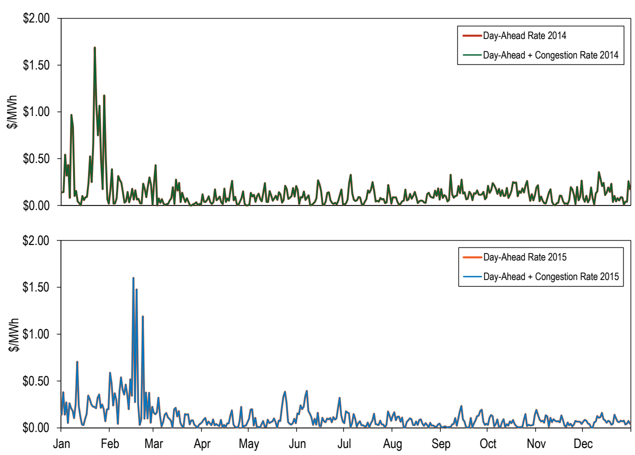


Figure 4-2 shows the RTO and the regional reliability rates for 2014 and 2015. The average daily RTO reliability rate was $0.045 per MWh. The highest RTO reliability rate in 2015 occurred on February 19, when the rate reached $0.772 per MWh, $23.821 per MWh lower than the $24.593 per MWh rate reached in 2014, on January 28.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2014 and 2015

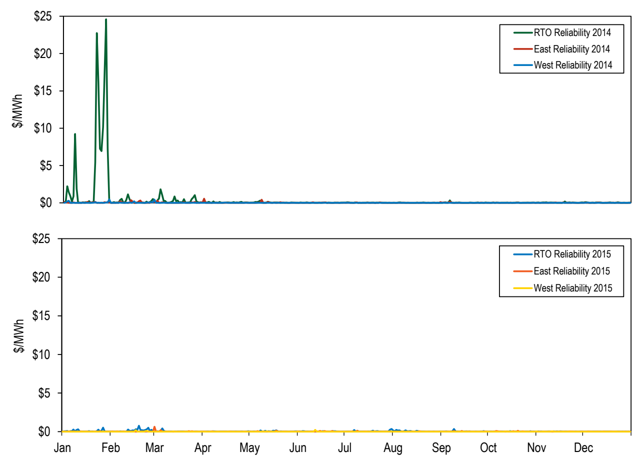


Figure 4-3 shows the RTO and regional deviation rates for 2014 and 2015. The average daily RTO deviation rate was $0.481 per MWh. The highest daily rate in 2015 occurred on February 17, when the RTO deviation rate reached $12.507 per MWh, $7.590 per MWh lower than the $20.097 per MWh rate reached in 2014, on January 25.

5 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.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2014 and 2015

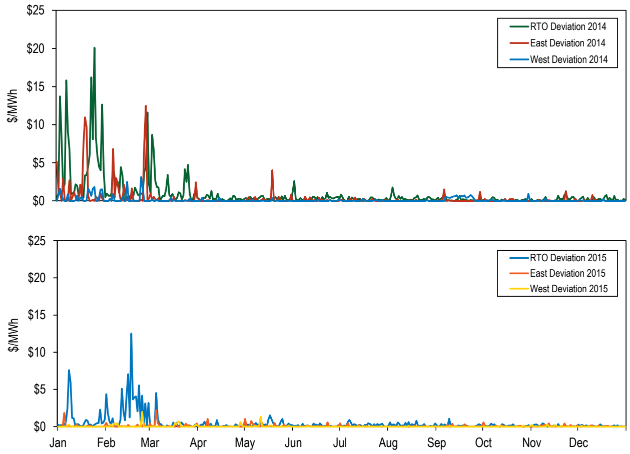


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2014 and 2015. The lost opportunity cost rate averaged $0.620 per MWh. The highest lost opportunity cost rate occurred on February 19, when it reached $13.330 per MWh, $19.045 per MWh lower than the $32.375 per MWh rate reached in 2014, January 24.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2014 and 2015

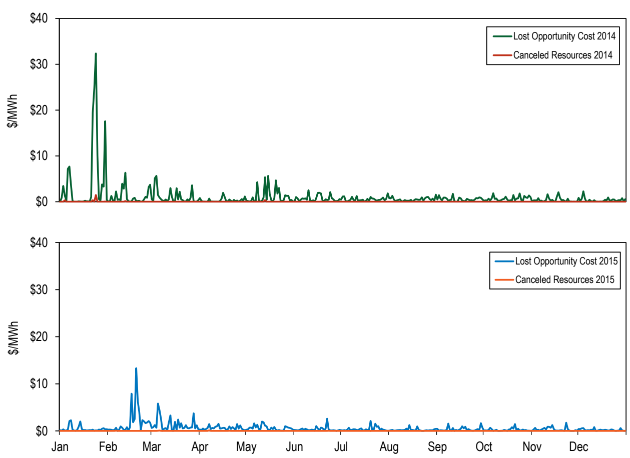


Table 4-12 shows the average rates for each region in each category in 2014 and 2015.

Table 4-12 Operating reserve rates ($/MWh): 2014 and 2015

Rate	2014 ($/MWh)	2015 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.134	0.120	(0.014)	(10.7%)
Day-Ahead with Unallocated Congestion	0.134	0.120	(0.014)	(10.7%)
RTO Reliability	0.540	0.045	(0.495)	(91.6%)
East Reliability	0.018	0.011	(0.007)	(40.6%)
West Reliability	0.008	0.003	(0.005)	(66.7%)
RTO Deviation	1.159	0.481	(0.678)	(58.5%)
East Deviation	0.330	0.068	(0.262)	(79.3%)
West Deviation	0.125	0.030	(0.095)	(76.0%)
Lost Opportunity Cost	1.196	0.620	(0.576)	(48.2%)
Canceled Resources	0.011	0.001	(0.009)	(86.4%)

Table 4-13 shows the operating reserve cost of a one MW transaction in 2015. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $1.187 per MWh with a maximum rate of $17.552 per MWh, a minimum rate of $0.039 per MWh and a standard deviation of $1.941 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): 2015

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.264	1.072	0.006	1.878
	DEC	17.522	1.187	0.039	1.941
	DA Load	1.600	0.115	0.000	0.160
	RT Load	0.773	0.050	0.000	0.093
	Deviation	17.264	1.072	0.006	1.878
West	INC	17.264	1.036	0.006	1.854
	DEC	17.522	1.151	0.039	1.919
	DA Load	1.600	0.115	0.000	0.160
	RT Load	0.772	0.042	0.000	0.086
	Deviation	17.264	1.036	0.006	1.854

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. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments. These charges are separate from the reactive service revenue requirement charges which are a fixed annual charge based on approved FERC filings. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer.

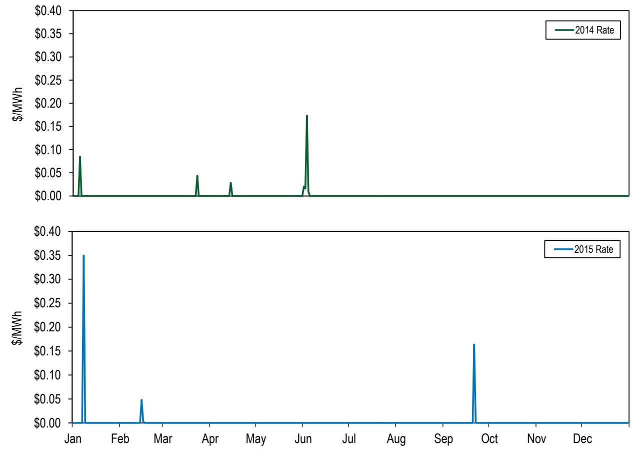
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in 2014 and 2015. Table 4-14 shows that in 2015 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.124 per MWh for reactive services associated with local voltage support, $0.273 or 68.8 percent lower than the average rate paid in 2014.

Table 4-14 Local voltage support rates: 2014 and 2015

Control Zone	2014 ($/MWh)	2015 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.009	0.000	(0.009)	(99.8%)
AEP	0.006	0.002	(0.004)	(71.3%)
AP	0.005	0.000	(0.005)	(98.8%)
ATSI	0.177	0.056	(0.121)	(68.3%)
BGE	0.001	0.000	(0.001)	(100.0%)
ComEd	0.000	0.000	(0.000)	(79.6%)
DAY	0.001	0.000	(0.001)	(87.8%)
DEOK	0.000	0.000	0.000	NA
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.044	0.027	(0.017)	(39.3%)
DPL	0.397	0.124	(0.273)	(68.8%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.001	0.000	(0.001)	(100.0%)
Met-Ed	0.002	0.002	0.000	12.6%
PECO	0.008	0.000	(0.008)	(100.0%)
PENELEC	0.185	0.016	(0.169)	(91.1%)
Pepco	0.001	0.000	(0.000)	(50.9%)
PPL	0.000	0.000	(0.000)	(21.9%)
PSEG	0.008	0.000	(0.008)	(100.0%)
RECO	0.000	0.000	0.000	0.0%

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2014 and 2015. The average rate in 2015 was $0.0019 per MWh, 82.8 percent higher than the $0.0010 per MWh average rate in 2014.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2014 and 2015



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in 2014 and 2015. Total real-time load and real-time exports were 14,857,282 MWh or 1.8 percent lower in 2015 compared to 2014. Total deviations summed across the demand, supply, and generator categories were 6,449,476 MWh or 5.0 percent higher in 2015 compared to 2014.

Table 4-15 Balancing operating reserve determinants (MWh): 2014 and 2015

		Reliability Charge Determinants (MWh)			Deviation Charge Determinants (MWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2014	RTO	780,507,569	28,586,455	809,094,024	78,151,362	19,990,949	32,114,416	130,256,727
	East	366,534,760	10,893,403	377,428,163	37,923,259	11,159,910	15,122,684	64,205,854
	West	413,972,809	17,693,052	431,665,861	39,345,660	8,426,967	16,991,733	64,764,359
2015	RTO	776,092,885	18,143,858	794,236,742	81,604,825	23,096,560	32,004,819	136,706,204
	East	368,942,881	9,859,610	378,802,491	41,839,924	12,258,045	16,557,937	70,655,907
	West	407,150,004	8,284,248	415,434,252	38,974,508	10,521,360	15,446,881	64,942,749
Difference	RTO	(4,414,684)	(10,442,597)	(14,857,282)	3,453,463	3,105,611	(109,598)	6,449,476
	East	2,408,121	(1,033,793)	1,374,328	3,916,665	1,098,135	1,435,253	6,450,053
	West	(6,822,805)	(9,408,804)	(16,231,609)	(371,152)	2,094,394	(1,544,851)	178,390

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In 2015, 24.3 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 75.7 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: 2015

Deviation		Deviation (MWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	367,885	347,416	20,469	0.3%	0.5%	0.0%
	DECs Only	11,024,474	5,698,789	4,535,292	8.1%	8.1%	7.0%
	Exports Only	4,178,051	2,164,522	2,013,528	3.1%	3.1%	3.1%
	Load Only	56,539,555	27,432,416	29,107,139	41.4%	38.8%	44.8%
	Combination with DECs	6,590,376	4,895,331	1,695,046	4.8%	6.9%	2.6%
	Combination without DECs	2,904,484	1,301,451	1,603,033	2.1%	1.8%	2.5%
Supply	Bilateral Purchases Only	143,923	122,543	21,380	0.1%	0.2%	0.0%
	Imports Only	7,170,390	3,898,355	3,272,035	5.2%	5.5%	5.0%
	INCs Only	12,127,901	6,093,629	5,717,118	8.9%	8.6%	8.8%
	Combination with INCs	3,533,255	2,038,398	1,494,857	2.6%	2.9%	2.3%
	Combination without INCs	121,091	105,121	15,971	0.1%	0.1%	0.0%
Generators		32,004,819	16,557,937	15,446,881	23.4%	23.4%	23.8%
Total		136,706,204	70,655,907	64,942,749	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in 2014 and 2015. During 2015, 63.5 percent of total energy uplift credits were in the balancing operating reserve category, a decrease of 18.4 percentage points from 81.9 in 2014.

Table 4-17 Energy uplift credits by category: 2014 and 2015

Category	Type	2014 Credits (Millions)	2015 Credits (Millions)	Change	Percent Change	2014 Share	2015 Share
Day-Ahead	Generators	$111.3	$98.5	($12.8)	(11.5%)	11.6%	31.4%
	Imports	$0.0	$0.0	$0.0	178.8%	0.0%	0.0%
	Load Response	$0.0	$0.2	$0.2	3,298.2%	0.0%	0.1%
Balancing	Canceled Resources	$1.4	$0.2	($1.2)	(85.8%)	0.1%	0.1%
	Generators	$627.2	$113.6	($513.7)	(81.9%)	65.3%	36.1%
	Imports	$0.1	$0.2	$0.0	39.0%	0.0%	0.1%
	Load Response	$0.0	$0.1	$0.1	258.4%	0.0%	0.0%
	Local Constraints Control	$1.9	$0.9	($1.1)	(55.7%)	0.2%	0.3%
	Lost Opportunity Cost	$155.8	$84.8	($71.1)	(45.6%)	16.2%	27.0%
Reactive Services	Day-Ahead	$24.9	$7.7	($17.2)	(69.1%)	2.6%	2.4%
	Local Constraints Control	$0.0	$0.0	($0.0)	(87.3%)	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.1	($0.1)	(52.9%)	0.0%	0.0%
	Reactive Services	$3.4	$2.7	($0.7)	(21.3%)	0.4%	0.9%
	Synchronous Condensing	$0.9	$0.2	($0.7)	(81.7%)	0.1%	0.1%
Synchronous Condensing		$0.1	$0.0	($0.1)	(76.1%)	0.0%	0.0%
Black Start Services	Day-Ahead	$27.4	$4.3	($23.1)	(84.2%)	2.9%	1.4%
	Balancing	$5.2	$0.5	($4.7)	(91.0%)	0.5%	0.1%
	Testing	$0.4	$0.4	$0.0	7.1%	0.0%	0.1%
Total		$960.3	$314.2	($646.1)	(67.3%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in 2014 and 2015. The decrease in energy uplift in 2015 compared to 2014 was due to lower credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal) in the 2015 winter compared to the 2014 winter. Credits to these units decreased $553.2 million or 71.9 percent mainly because these units' offers were affected by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $93.2 million.

Table 4-18 Energy uplift credits by unit type: 2014 and 2015

Unit Type	2014 Credits (Millions)	2015 Credits (Millions)	Change	Percent Change	2014 Share	2015 Share
Combined Cycle	$399.2	$72.5	($326.6)	(81.8%)	41.6%	23.1%
Combustion Turbine	$256.1	$114.1	($142.0)	(55.4%)	26.7%	36.4%
Diesel	$3.0	$1.9	($1.1)	(36.8%)	0.3%	0.6%
Hydro	$1.7	$1.1	($0.5)	(32.4%)	0.2%	0.4%
Nuclear	$0.3	$0.4	$0.2	62.7%	0.0%	0.1%
Solar	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Steam - Coal	$178.1	$89.8	($88.3)	(49.6%)	18.6%	28.6%
Steam - Other	$113.7	$29.1	($84.6)	(74.4%)	11.8%	9.3%
Wind	$8.1	$4.7	($3.4)	(41.9%)	0.8%	1.5%
Total	$960.2	$313.7	($646.4)	(67.3%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in 2015. Combined cycle units received 24.0 percent of the day-ahead generator credits in 2015, 8.9 percentage points lower than the share received in 2014. Combined cycle units received 39.1 percent of the balancing generator credits in 2015, 17.1 percentage points lower than the share received in 2014. Combustion turbines and diesels received 85.6 percent of the lost opportunity cost credits in 2015, 16.7 percentage points higher than the share received in 2014.

Table 4-19 Energy uplift credits by unit type: 2015

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	24.0%	39.1%	0.0%	1.7%	2.7%	19.4%	0.0%	1.7%
Combustion Turbine	3.6%	33.0%	24.5%	7.4%	84.8%	6.7%	100.0%	7.1%
Diesel	0.0%	1.0%	0.0%	10.3%	0.8%	0.3%	0.0%	0.0%
Hydro	0.9%	0.1%	75.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%
Steam - Coal	63.3%	11.5%	0.0%	80.6%	5.6%	39.6%	0.0%	91.2%
Steam - Others	8.2%	15.2%	0.0%	0.0%	0.1%	34.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.0%	5.4%	0.0%	0.0%	0.0%
Total (Millions)	$98.5	$113.6	$0.2	$0.9	$84.8	$10.6	$0.0	$5.2

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In 2015, coal units received 39.6 percent of all reactive services credits, 29.6 percentage points lower than the share received in 2014. Coal units received 91.2 percent of all black start services credits in 2015 as a result of the ALR units.

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 almost impossible for competition to affect these payments.

Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 34.2 percent of total energy uplift credits in 2015, compared to 33.7 percent in 2014. In 2015, 246 units received 90 percent of all energy uplift credits, compared to 226 units in 2014.

Figure 4-6 Cumulative share of energy uplift credits in 2014 and 2015 by unit

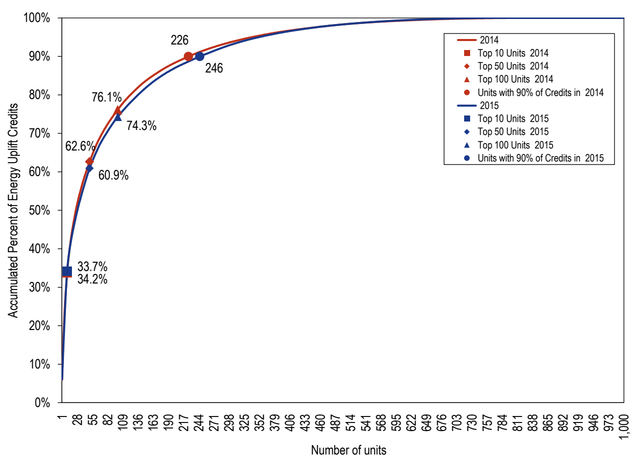


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: 2015

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$58.8	59.7%	$94.2	95.6%
Balancing	Canceled Resources	$0.2	93.7%	$0.2	100.0%
	Generators	$50.8	44.8%	$91.2	80.3%
	Local Constraints Control	$0.8	88.2%	$0.9	100.0%
	Lost Opportunity Cost	$19.2	22.6%	$64.3	75.8%
Reactive Services		$9.1	85.6%	$10.6	99.9%
Synchronous Condensing		$0.0	94.7%	$0.0	100.0%
Black Start Services		$4.8	93.1%	$5.1	99.5%
Total		$107.2	34.2%	$244.8	78.0%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2015, 72.7 percent of all credits paid to these units were allocated to deviations while the remaining 27.3 percent were paid for reliability reasons.

Table 4-21 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2015

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$13.9	$0.0	$0.0	$36.4	$0.6	$0.0	$50.8
Share	27.3%	0.1%	0.0%	71.5%	1.1%	0.0%	100.0%

In 2015, concentration in all energy uplift credit categories was high.[6,7] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-22 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 5828, for balancing operating reserve credits to generators was 3740, for lost opportunity cost credits was 3788 and for reactive services credits was 9093.

Table 4-22 Daily energy uplift credits HHI: 2015

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	5828	1509	10000	100.0%	42.0%
	Imports	10000	10000	10000	100.0%	58.1%
	Load Response	10000	10000	10000	100.0%	99.3%
Balancing	Canceled Resources	9897	5650	10000	100.0%	63.5%
	Generators	3737	913	9979	99.9%	32.1%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9890	7043	10000	100.0%	54.8%
	Lost Opportunity Cost	3786	699	10000	100.0%	15.9%
Reactive Services		9093	2780	10000	100.0%	24.1%
Synchronous Condensing		10000	10000	10000	100.0%	74.7%
Black Start Services		9605	4140	10000	100.0%	89.8%
Total		2569	627	8938	94.5%	21.3%

6 See *2015 State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
7 Table 4-22 excludes local constraints control categories.

Economic and Noneconomic Generation[8]

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 4-23 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 2015, 35.6 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 33.8 percent of the real-time generation was eligible for balancing operating reserve credits.[9]

8 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.

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

Table 4-23 Day-ahead and real-time generation (GWh): 2015

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	803,408	286,030	35.6%
Real-Time	794,089	268,721	33.8%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In 2015, 88.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.2 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-24 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 4-24 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2015

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	251,703	34,327	88.0%	12.0%
Real-Time	196,714	72,007	73.2%	26.8%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-25 shows the generation receiving day-ahead and balancing operating reserve credits. In 2015, 5.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 4.8 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-25 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2015

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	286,030	14,169	5.0%
Real-Time	196,714	9,498	4.8%

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 (ALR) 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.[10] 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.[11] 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 4-26 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In 2015, 1.9 percent of the total day-ahead generation was scheduled as must run by PJM, 2.1 percentage points lower than 2014.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): 2014 and 2015

	2014			2015		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	81,479	2,627	3.2%	77,937	2,143	2.7%
Feb	70,942	3,404	4.8%	74,224	2,904	3.9%
Mar	72,681	2,892	4.0%	68,201	1,857	2.7%
Apr	60,688	2,825	4.7%	55,957	1,138	2.0%
May	61,919	2,808	4.5%	61,955	1,523	2.5%
Jun	70,230	3,421	4.9%	68,558	1,447	2.1%
Jul	75,606	3,733	4.9%	75,490	1,201	1.6%
Aug	73,003	2,778	3.8%	73,934	922	1.2%
Sep	65,066	2,792	4.3%	66,927	616	0.9%
Oct	61,223	2,444	4.0%	58,731	763	1.3%
Nov	64,991	1,859	2.9%	58,517	486	0.8%
Dec	70,853	2,023	2.9%	62,976	551	0.9%
Total	828,682	33,607	4.1%	803,408	15,552	1.9%

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 4-27 Day-ahead generation scheduled as must run by PJM by category (GWh): 2015

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	173	145	848	977	2,143
Feb	137	26	725	2,016	2,904
Mar	177	139	387	1,154	1,857
Apr	4	236	263	634	1,138
May	3	29	459	1,032	1,523
Jun	0	0	670	778	1,447
Jul	0	0	422	779	1,201
Aug	0	1	447	474	922
Sep	0	29	359	227	616
Oct	0	0	417	346	763
Nov	0	0	392	94	486
Dec	0	0	360	192	551
Total	495	605	5,749	8,703	15,552
Share	3.2%	3.9%	37.0%	56.0%	100.0%

Table 4-27 shows the total day-ahead generation scheduled as must run by PJM by category. In 2015, 44.0 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 3.2. percent was generation from units scheduled to provide black start services, 3.9 percent was generation from units scheduled to provide reactive services and 37.0 percent was generation paid normal day-ahead operating reserve credits. The remaining 56.0 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Total day-ahead operating reserve credits in 2015 were $98.5 million, of which $69.2 million or 70.2 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-28 shows the geography of charges and credits in 2015. Table 4-28 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.

10 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-minutes.ashx>.

11 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-28 Geography of regional charges and credits: 2015[12]

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$4.2	$3.8	($0.5)	1.4%	1.3%	0.4%	0.0%
	AEP - EKPC	$43.9	$25.7	($18.2)	14.8%	8.6%	15.3%	0.0%
	AP - DLCO	$21.9	$16.0	($5.9)	7.4%	5.4%	5.0%	0.0%
	ATSI	$19.9	$7.6	($12.3)	6.7%	2.5%	10.4%	0.0%
	BGE - Pepco	$23.2	$79.6	$56.4	7.8%	26.8%	0.0%	47.5%
	ComEd - External	$28.8	$17.3	($11.5)	9.7%	5.8%	9.7%	0.0%
	DAY - DEOK	$16.1	$5.1	($11.0)	5.4%	1.7%	9.2%	0.0%
	Dominion	$29.6	$36.9	$7.4	9.9%	12.4%	0.0%	6.2%
	DPL	$7.9	$14.0	$6.1	2.7%	4.7%	0.0%	5.1%
	JCPL	$7.3	$2.3	($5.0)	2.5%	0.8%	4.2%	0.0%
	Met-Ed	$5.5	$1.7	($3.8)	1.9%	0.6%	3.2%	0.0%
	PECO	$13.9	$6.4	($7.5)	4.7%	2.1%	6.3%	0.0%
	PENELEC	$9.1	$11.8	$2.7	3.1%	4.0%	0.0%	2.3%
	PPL	$15.1	$6.8	($8.2)	5.1%	2.3%	6.9%	0.0%
	PSEG	$15.8	$62.1	$46.3	5.3%	20.9%	0.0%	39.0%
	RECO	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	All Zones	$262.6	$297.0	$34.4	88.4%	99.9%	71.0%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.6	$0.0	($0.6)	0.2%	0.0%	0.5%	0.0%
	Dominion	$1.0	$0.0	($1.0)	0.3%	0.0%	0.8%	0.0%
	Eastern	$0.4	$0.0	($0.4)	0.1%	0.0%	0.3%	0.0%
	New Jersey	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$0.3	$0.0	($0.3)	0.1%	0.0%	0.2%	0.0%
	Western	$6.7	$0.0	($6.7)	2.3%	0.0%	5.6%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$9.5	$0.0	($9.5)	3.2%	0.0%	8.0%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.4	$0.0	($0.4)	0.1%	0.0%	0.3%	0.0%
	IMO	$5.2	$0.0	($5.2)	1.8%	0.0%	4.4%	0.0%
	Linden	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	MISO	$3.8	$0.0	($3.8)	1.3%	0.0%	3.2%	0.0%
	Neptune	$0.8	$0.0	($0.8)	0.3%	0.0%	0.7%	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%	0.1%	0.0%
	NYIS	$5.0	$0.0	($5.0)	1.7%	0.0%	4.2%	0.0%
	OVEC	$1.0	$0.0	($1.0)	0.3%	0.0%	0.9%	0.0%
	South Exp	$2.3	$0.0	($2.3)	0.8%	0.0%	1.9%	0.0%
	South Imp	$5.8	$0.0	($5.8)	1.9%	0.0%	4.8%	0.0%
	All Interfaces	$25.0	$0.2	($24.9)	8.4%	0.1%	21.0%	0.0%
	Total	$297.2	$297.2	$0.0	100.0%	100.0%	100.0%	100.0%

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 1.3 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had 0.4 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 5.3 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 20.9 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had 39.0 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 88.4 percent of all charges were allocated in control zones, 3.2 percent in hubs and aggregates and 8.4 percent in interfaces.

12 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-28 does not include synchronous condensing, local constraint control, black start services and reactive services charges and credits since these are allocated zonally.

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 4-29 shows the geography of reactive services charges. In 2015, 85.9 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 14.0 percent were paid by real-time load in across the entire RTO and 0.2 percent were paid by real-time load in multiple zones. In 2015, the top three zones accounted for 80.9 percent of all the reactive services charges allocated to single zones.

Table 4-29 Geography of reactive services charges: 2015[13]

Location	Charges (Millions)	Share of Charges
Single Zone	$9.1	85.9%
Multiple Zones	$0.0	0.2%
Entire RTO	$1.5	14.0%
Total	$10.6	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 92.7 percent of all the black start services costs in 2015. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

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.[14] 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 to as real-time LOC.

In 2015, LOC credits decreased by $71.1 million, 45.6 percent, compared to 2014. The decrease of $71.1 million is comprised of a decrease of $35.4 million in day-ahead LOC and a decrease of $35.7 million in real-time LOC. Table 4-30 shows the monthly composition of LOC credits in 2014 and 2015. In 2015, 18.2 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 5.3 percentage points lower than in 2014.

13 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).

14 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 4-30 Monthly lost opportunity cost credits (Millions): 2014 and 2015

	2014			2015		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$44.2	$29.9	$74.1	$4.4	$0.9	$5.2
Feb	$5.9	$5.4	$11.3	$23.0	$3.0	$25.9
Mar	$8.3	$4.1	$12.4	$13.9	$1.5	$15.4
Apr	$1.6	$1.4	$3.0	$5.2	$0.5	$5.7
May	$10.4	$2.5	$12.9	$5.7	$1.8	$7.5
Jun	$7.2	$1.2	$8.4	$4.1	$0.4	$4.5
Jul	$6.2	$0.3	$6.5	$4.5	$0.4	$4.9
Aug	$5.2	$0.1	$5.3	$2.2	$0.4	$2.6
Sep	$5.3	$0.7	$6.0	$3.2	$1.3	$4.5
Oct	$5.5	$1.5	$7.0	$1.8	$0.6	$2.3
Nov	$3.9	$0.7	$4.7	$2.1	$1.6	$3.7
Dec	$4.0	$0.2	$4.2	$2.4	$0.0	$2.5
Total	$107.8	$48.0	$155.8	$72.4	$12.3	$84.8
Share	69.2%	30.8%	100.0%	85.4%	14.6%	100.0%

Table 4-31 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 4-31 shows that while day-ahead scheduled generation from CTs and diesels increased 4,106 GWh, 28.1 percent, from 14,628 GWh in the 2014 to 18,734 GWh in 2015, the generation that received LOC credits decreased by 25 GWh or 0.7 percent.

Table 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2014 and 2015

	2014			2015		
	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	2,150	834	346	827	347	244
Feb	763	301	150	1,593	838	499
Mar	976	230	122	1,368	688	505
Apr	438	170	47	1,392	536	408
May	1,206	615	384	1,898	561	369
Jun	1,363	557	356	1,736	445	272
Jul	1,657	532	368	2,651	479	316
Aug	1,791	636	453	1,881	341	208
Sep	1,550	536	396	1,714	291	192
Oct	1,380	571	426	1,375	224	116
Nov	683	284	133	1,258	212	102
Dec	671	340	258	1,041	317	182
Total	14,628	5,605	3,439	18,734	5,279	3,414
Share	100.0%	38.3%	23.5%	100.0%	28.2%	18.2%

In 2015, the top three control zones in which generation received LOC credits, Dominion, AEP and ComEd, accounted for 47.1 percent of all LOC credits, 41.5 percent of all the day-ahead generation from combustion turbines and diesels, 39.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 38.6 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 4-32 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 4-32 shows that in 2015, $45.0 million or 62.1 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 6.0 percentage points higher than 2014.

Table 4-32 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2014 and 2015

	2014			2015		
	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	$19.6	$24.5	$44.2	$2.4	$2.0	$4.4
Feb	$3.6	$2.3	$5.9	$15.4	$7.5	$23.0
Mar	$3.6	$4.7	$8.3	$9.1	$4.8	$13.9
Apr	$0.8	$0.8	$1.6	$3.0	$2.2	$5.2
May	$8.2	$2.2	$10.4	$3.1	$2.7	$5.7
Jun	$5.4	$1.8	$7.2	$2.3	$1.8	$4.1
Jul	$3.8	$2.4	$6.2	$2.7	$1.8	$4.5
Aug	$3.7	$1.5	$5.2	$1.3	$0.8	$2.2
Sep	$3.0	$2.2	$5.3	$1.7	$1.5	$3.2
Oct	$3.3	$2.2	$5.5	$1.0	$0.8	$1.8
Nov	$2.9	$1.1	$3.9	$1.2	$0.9	$2.1
Dec	$2.6	$1.4	$4.0	$1.8	$0.6	$2.4
Total	$60.5	$47.3	$107.8	$45.0	$27.4	$72.4
Share	56.2%	43.8%	100.0%	62.1%	37.9%	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 4-33 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 4-33 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 2015, 66.4 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 33.6 percent was noneconomic.

Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2014 and 2015[15]

	2014			2015		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	344	356	701	246	102	348
Feb	117	170	288	497	335	832
Mar	116	112	228	543	140	682
Apr	49	130	179	366	168	534
May	333	238	571	281	261	542
Jun	269	234	502	257	144	401
Jul	245	232	477	287	138	425
Aug	268	346	614	165	128	293
Sep	298	225	524	217	74	292
Oct	332	231	563	149	59	208
Nov	82	174	256	121	70	191
Dec	214	116	330	214	75	289
Total	2,667	2,565	5,232	3,343	1,693	5,036
Share	51.0%	49.0%	100.0%	66.4%	33.6%	100.0%

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not committed by PJM in real time when they are economic.

15 The total generation in Table 4-33 is lower than the day-ahead generation not requested in real time in Table 4-31 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-33 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

Black Start Service Units

Certain units located in the AEP Control Zone that had been relied on for their black start capability were replaced as black start resources on April 1, 2015. These black start units provided black start service under the automatic load rejection (ALR) option, which means that the units had to be running in order to provide black start service even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units resulted in make whole payments in the form of operating reserve credits.

As a result of the replacement of these ALR units, the cost of the noneconomic operation of ALR units in the AEP Control Zone in 2015 decreased by $27.8 million compared to 2014. In 2015, the cost of the noneconomic operation of these units was $4.8 million, and 94.6 percent of this cost was paid by peak transmission use in the AEP Control Zone while the remaining 5.4 percent was paid by non-zone peak transmission use.[16] 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 $0.51 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 $0.004 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[17] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Eleven of the 17 (65 percent) closed loop interface definitions were created for the purpose of allowing emergency DR to set price.

Closed loop interfaces are used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside the loop with the rest of PJM. PJM reduces the interface real transfer capability to a level that will artificially make marginal the resource selected by PJM. Table 4-34 shows the closed loop interfaces that PJM has defined.

16 Non-zone peak transmission use is based on interchange transaction MW reservations.

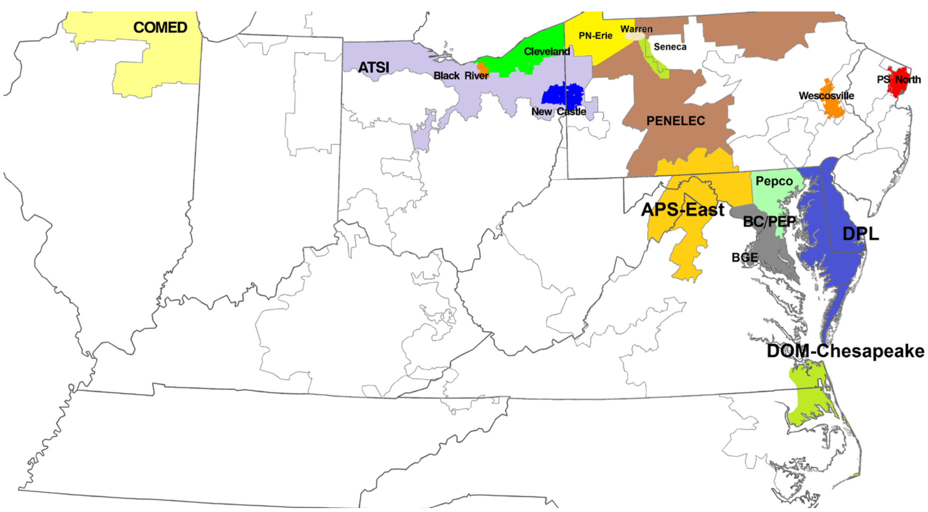
17 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

Table 4-34 PJM Closed loop interfaces[18,19,20]

Interface	Control Zone(s)	Objective	Effective Date	Limit Calculation
APS-East	AP	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
ATSI	ATSI	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 17, 2013	Limit equal to actual flow
BC	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
BC/PEP	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area	NA	PJM Transfer Limit Calculator
Black River	ATSI	Allow emergency DR resources set real-time LMP	September 1, 2014	Limit equal to actual flow
Cleveland	ATSI	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
COMED	ComEd	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
DOM-Chesapeake	Dominion	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	August 14, 2015	Limit equal to actual flow
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
New Castle	ATSI	Allow emergency DR resources set real-time LMP	July 1, 2014	Limit equal to actual flow
PENELEC	PENELEC	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	April 22, 2015	Limit equal to actual flow
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
PL-Wescosville	PPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 24, 2014	Limit equal to actual flow
PN-Erie	PENELEC	Allow emergency DR resources set real-time LMP	April 22, 2015	Limit equal to actual flow
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction	NA	NA
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	February 1, 2014	Limit equal to actual flow
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	September 26, 2014	Limit equal to actual flow

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

Figure 4-7 PJM Closed loop interfaces map



PJM's uses closed loop interfaces to artificially use the strike price of emergency DR to set LMP. This use of closed loop interfaces permits subjective price setting by PJM. PJM has not explained why the economic fundamentals require that DR strike prices set LMP when the resource is not marginal. Although DR should be nodal, DR is not nodal and cannot routinely set price in an LMP model. The MMU has recommended that DR be nodal so that it can set price when appropriate. The current PJM rules permit emergency DR to set a strike price as high as $1,849. There are no incentives for DR to set strike prices at an economically rational level because emergency DR is guaranteed the payment of its strike price whenever called. The MMU has recommended that emergency DR have an offer cap no higher than generation resources, that emergency DR be required to make offers in the Day-Ahead Energy Market like other capacity resources and the emergency DR be paid LMP rather than a guaranteed strike price when called

18 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
19 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
20 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

on. PJM's use of closed loop interfaces is a result of significant deficiencies in the rules governing DR. PJM's use of closed loop interfaces is also result of significant issues with PJM's scarcity pricing model which is not adequately locational. PJM uses closed loop interfaces and emergency DR strike prices as a substitute for improved scarcity pricing.

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are forced to be marginal in the model even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates 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 forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[21]

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 distortion of the way in which the transmission network is modeled. The use of closed loop interfaces is a distortion of the model.

The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason.

Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's notice, and therefore cannot be dispatched nodally or set price nodally. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

Price Setting Logic

In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic.

The application of the price setting logic reduces energy uplift payments by artificially increasing the LMP. The price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.

PJM and Alstom presented examples of this approach at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software.[22] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50

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

22 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Reduce the economic minimum of generator B to zero MW. Solution 3: Reduce the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

In solution 2, generator B is dispatched at 10 MW, despite the fact that this is physically impossible. This allows generator A to increase its output to 80 MW, which makes the transmission constraint binding and causes price separation between the two buses. This is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

In solution 3, the line limit is reduced from 80 MW to 40 MW, despite the fact that this is not the actual limit. As a result, generator A is dispatched to 40 MW (10 MW less than the original solution), the transmission line constraint is binding and congestion occurs. The goal is met and energy uplift is reduced to zero because the LMPs at both buses are increased so that they equal or exceed the generators' offers. Again, this is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

Attempting to reduce uplift at the expense of fundamental LMP logic is not consistent with the objective of clearing the market using a least cost approach. The result of PJM's price setting logic in this example is to increase total production costs.

The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.

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.[23]

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

Energy Uplift Recommendations

Recommendations for Calculation of Credits

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. Units do not incur costs 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

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

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.[24]

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 until the unit actually operates or does not operate. 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 net revenues 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 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.[25] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[26] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation in 2014 and 2015. In 2014 and 2015, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $71.6 million or 19.3 percent ($9.2 million paid to units providing reactive support, $6.7 million paid to units providing black start support and $55.7 million paid to units as day-ahead and balancing operating reserves).

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

25 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.

26 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>.

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. If the day-ahead operating reserve category is eliminated but the MMU's uplift allocation recommendations are not implemented, units that clear the Day-Ahead Energy Market will be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the PJM Regulation Market. The filing included four elements: implement the TPS test in the PJM 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 four elements were based on a settlement rather than a rational evaluation of an efficient market design.

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 and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

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 and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2014 and 2015, 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 $14.2 million, of which $10.3 million or 72.6 percent was due to generators that elected to self-schedule for regulation while noneconomic and receiving balancing operating reserve credits.[27]

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[28] 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 clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units 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 separately for each hour 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

27 These estimates take into account the elimination of the day-ahead operating reserve category.
28 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>.

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.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup cost when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for hour 9, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour 9 because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 18 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

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.[29]

- **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 be calculated using the schedule on which the unit was scheduled to run in the energy market.

  This recommendation was adopted on September 1, 2015.[30]

- **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 and overstate LOC credits as a result. 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.

  This recommendation was adopted on September 1, 2015.[31]

- **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. This is the only correct way to calculate the lost opportunity cost.

  This recommendation was adopted on September 1, 2015.[32]

- **Segmented Calculation:** Current rules calculate LOC on an hourly basis; each hour is treated as a standalone calculation. This means that units receive an LOC payment during hours in which it is economic for them to run and receive the benefit of not being called on during hours in which it is not

29 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>.

30 152 FERC ¶ 61,165 (2015).

31 *Id.*

32 *Id.*

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 inconsistent with the basic PJM energy uplift logic. If a unit does not run in real time, it loses net revenues if the real-time LMP is greater than the unit's offer but it gains net revenues if the real-time LMP is lower than the unit's offer. The correct lost opportunity costs for units that clear the Day-Ahead Energy Market and are not committed in real time cannot be determined if profitable hours are arbitrarily excluded. In the case of separate hourly calculations, units are overcompensated compared to the net revenues they would have received had they run.

The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

This recommendation has not been adopted.

These four recommendations 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 forecast LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' schedule on which it is committed.

Table 4-35 shows the impact that each of these changes would have had on the LOC credits in the energy market in 2015, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $21.8 million, or 25.7 percent, if all these changes had been implemented.[33]

33 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.

Table 4-35 Impact on energy market lost opportunity cost credits of rule changes (Millions): 2015

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$12.3	$72.3	$84.6
Impact 1: Committed Schedule	$0.4	$5.6	$6.0
Impact 2: Using Offer Curve	($0.3)	$6.9	$6.6
Impact 3: Including No Load Cost	NA	($18.2)	($18.2)
Impact 4: Including Startup Cost	NA	($6.4)	($6.4)
Impact 5: Segmented Calculation	NA	($9.8)	($9.8)
Net Impact	$0.1	($21.9)	($21.8)
Credits After Changes	$12.4	$50.4	$62.9

In addition to these four recommendations, the MMU recommends three additional steps to address issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output.

  The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.

  The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output.

- **Intra-Hour Calculations:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the

Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero that means the unit was committed during that hour. But in real time a unit may be committed for part of an hour. The calculation of LOC does not reflect the exact time at which the unit was turned on.

The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour.

- **LOC Unit Type Eligibility:** The current rules compensate only CTs and diesels for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. The reason for this difference is that other unit types have a commitment obligation when scheduled in the Day-Ahead Energy Market. For example, steam turbines and combined cycle units commitment instructions are their day-ahead schedule. Units of these types that clear the Day-Ahead Energy Market are automatically committed to be on or remain on in real time. These units are eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment for reliability purposes. CT and diesel commitment instructions occur in real time even if these units were committed in the Day-Ahead Energy Market. CTs and diesels are committed in real time, after PJM dispatch has a more complete knowledge of real-time conditions. The goal is to permit the dispatch of flexible units in real time based on real-time conditions as they evolve. The reason for this special treatment of CTs and diesels is that historically, such units were usually more flexible to commit than other unit types. But that is no longer correct and should not be assumed to be correct.

  The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time.

Recommendations for Allocation of Charges

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 recommends that up to congestion transactions be required to pay energy uplift charges.

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.

Up to congestion transactions would have paid an average rate between $0.355 and $0.430 per MWh in 2014 and between $0.294 and $0.299 per MWh in 2015 if the MMU's recommendations regarding energy uplift had been in place.[34,35]

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.[36] Load, interchange transactions, internal bilateral transactions, demand

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

35 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 to 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.

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

resources, increment offers and decrement bids also incur deviations.

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 For example, a generator with a negative deviation (generation below the desired level) can offset such deviation if a generator at the same bus has a positive deviation (generation above the desired level) if this occurs in the same hour.

Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped by demand and supply, and then 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 at the same location at the same hour.[37] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset. 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 (IBTs) 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.

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 MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.

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.[38] 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.[39] These units are often run out of merit and receive substantial day-ahead and balancing operating reserve credits.

37 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.

38 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>.

39 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.

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.[40] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole for 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 2015, units providing reactive services were paid $1.1 million in balancing operating reserve credits in order to cover their total energy offer. In 2014, this misallocation was $2.3 million.

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, in addition to real-time load.[41]

Allocation Proposal

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

The current method 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 would shift these costs to the balancing operating reserve category which would 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 related to expected conditions in the real-time market not including 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 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

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

41 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>.

energy uplift payments are paid by transactions or resources affecting the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load, real-time exports and real-time wheels independently of the timing of the commitment.

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.

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

Table 4-36 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Unit not scheduled 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 4-37 MMU energy uplift allocation proposal

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market and committed in real time	Day-Ahead Segment Make Whole Credit	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

Table 4-37 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead 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.

Quantifiable Recommendations Impact

Table 4-38 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 $127.6 million or 10.7 percent in 2014 and 2015 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 $55.7 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $57.4 million and the use of net regulation revenues offset would have resulted in a decrease of $14.2 million.[42] Table 4-38 shows that deviations charges would have been reduced by $319.2 million or 64.4 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 4-38 Current and proposed energy uplift charges by allocation (Millions): 2014 and 2015[43]

Allocation	2014	2015	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$111.3	$98.7	$210.0
Real-Time Load and Real-Time Exports	$447.1	$41.1	$488.2
Deviations	$337.7	$157.7	$495.4
Total	$896.1	$297.5	$1,193.6
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$47.0	$27.5	$74.5
Real-Time Load and Real-Time Exports	$461.4	$99.7	$561.0
Deviations	$107.0	$69.2	$176.1
Physical Deviations	$203.2	$51.1	$254.4
Total	$818.6	$247.5	$1,066.1
Impact			
Impact ($)	($77.5)	($50.0)	($127.6)
Impact (%)	(8.7%)	(16.8%)	(10.7%)

The MMU calculated the rates that participants would have paid in 2014 and 2015 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 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 4-39 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2014 and 2015. Table 4-39 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 2014 and 2015. Table 4-39 shows for example

42 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 service charges.

43 These energy uplift charges do not include black start and reactive services charges.

that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.215 and $0.149 per MWh in the 2014 and 2015, under the first scenario, $2.189 and $1.038 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 $0.393 and $0.296 per MWh in 2014 and 2015 under the first scenario. Table 4-39 shows the current and proposed averages energy uplift rates for all transactions.

Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the 2014 level to 2015 level. The outside bars show the total energy uplift charges in 2014 (left side) and total energy uplift charges in 2015 (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 2015 (a decrease of $12.6 million).

Table 4-39 Current and proposed average energy uplift rate by transaction: 2014 and 2015[44]

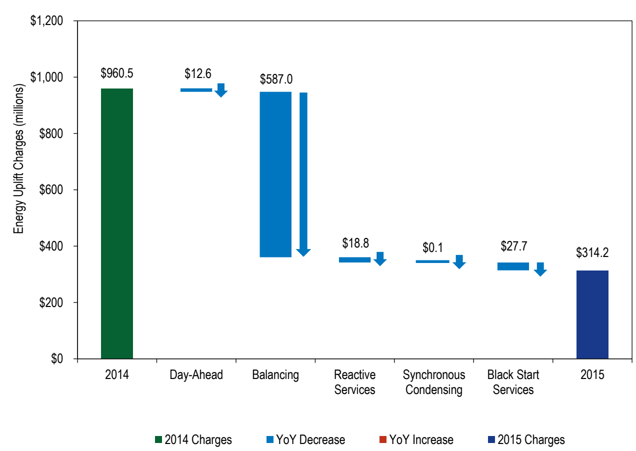
		2014			2015		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	2.275	0.215	0.681	1.072	0.149	0.383
	DEC	2.404	0.215	0.681	1.187	0.149	0.383
	DA Load	0.129	0.020	0.024	0.115	0.013	0.015
	RT Load	0.450	0.466	0.466	0.050	0.118	0.118
	Deviation	2.275	1.303	1.765	1.072	0.501	0.732
West	INC	2.069	0.177	0.568	1.036	0.147	0.383
	DEC	2.199	0.177	0.568	1.151	0.147	0.383
	DA Load	0.129	0.020	0.024	0.115	0.013	0.015
	RT Load	0.439	0.466	0.466	0.042	0.118	0.118
	Deviation	2.069	1.218	1.604	1.036	0.432	0.666
UTC	East to East	NA	0.430	1.362	NA	0.299	0.765
	West to West	NA	0.355	1.136	NA	0.294	0.766
	East to/from West	NA	0.393	1.249	NA	0.296	0.766

Analysis of Changes in Annual Uplift Charges

Energy uplift charges decreased by $646.3 million (67.3 percent), from $960.5 million in 2014 to $314.2 million in 2015. This decrease was primarily the result of lower energy uplift charges associated with units committed for conservative operations in the first three months of 2015 compared to the first three months of 2014.

The year over year change resulted from a decrease of $12.6 million in day-ahead operating reserve charges, a decrease of $587.0 million in balancing operating reserve charges, a decrease of $18.8 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $27.7 in black start services charges.

Figure 4-8 Energy uplift charges change from 2014 to 2015 by category



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

Five Year Energy Uplift Charges Analysis

Energy uplift charges decreased by $646.3 million (67.3 percent) in 2015 compared to 2014. A number of changes to factors affecting uplift charges implemented during the period from January 1, 2011, through December 31, 2013, resulted in a change to uplift beginning in January 2014 which were apparent in February 2014, after the polar vortex month of January 2014. From January 2011 through December 2013, energy uplift charges averaged $58.2 million per month, and from February 2014 through December 2015, energy uplift charges averaged $29.0 million, a reduction of $29.3 million per month, or 50 percent. Total energy uplift in January 2014 was $606.1 million. Prior to January 2014, the highest energy uplift in a month had been $131.8 million in December 2010. January 2014 was excluded from this analysis in order to focus on the factors affecting uplift prior to January 2014 and after January 2014.

Since 2011, a number of factors affected energy uplift in PJM:

- **Lower natural gas prices:** Energy uplift charges have been in part a result of the noneconomic commitment of gas fired units in the Eastern Region of PJM. The decline in natural gas prices has reduced the level of the associated uplift.
- **Lower summer peak demand:** Energy uplift charges have been in part a result of charges incurred on peak summer days. In particular, LOC payments to combustion turbines and diesels not called on by PJM during hours in which they cleared the Day-Ahead Energy Market were lower in 2014 and 2015 as a result of lower load, lower fuel costs and lower energy prices.
- **FMU adders:** Some owners of resources committed by PJM to provide reactive or voltage support elected to reduce the FMU adders of their units at the end of December 2013.[45]
- **FMU adders reform:** On October 31, 2014, the Commission approved a change to the rules governing FMU adders.[46] The result was to eliminate FMU adders in 2014 and 2015, which reduced the cost-based offers of units committed by PJM for reactive services, which reduced uplift.
- **Black start and reactive commitment improvement:** At the end of December 2013, PJM began to schedule fewer units in the BGE and Pepco control zones for reactive support. At the same time, PJM restarted modeling the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy Markets. The result was to eliminate energy uplift costs attributable to the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 26, 2013.
- **ALR black start units:** ALR black start units that had been paid uplift were replaced by much lower cost conventional black start units on April 1, 2015.
- **LOC calculation reform:** On September 1, 2015, the Commission approved several changes recommended by the MMU and PJM related to energy LOC calculations which reduced uplift.
- **CT commitment improvement:** In the first half of 2013, PJM implemented a new tool to improve the commitment of combustion turbines (combustion turbine optimizer or CTO). The result was a reduction in the MW of generation from combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.
- **Closed loop interfaces:** In 2013, PJM began to implement closed loop interfaces. By artificially increasing energy prices based on PJM's changes to the transmission model, uplift was reduced.
- **Price setting logic:** In November 2014, PJM implemented what it terms price setting logic that enables PJM operators to artificially modify the outcome of the fundamental LMP logic in order to increase prices and reduce uplift.

45 See the *2014 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift," at "Reactive Services Rates."
46 149 FERC ¶ 61,091 (2014).

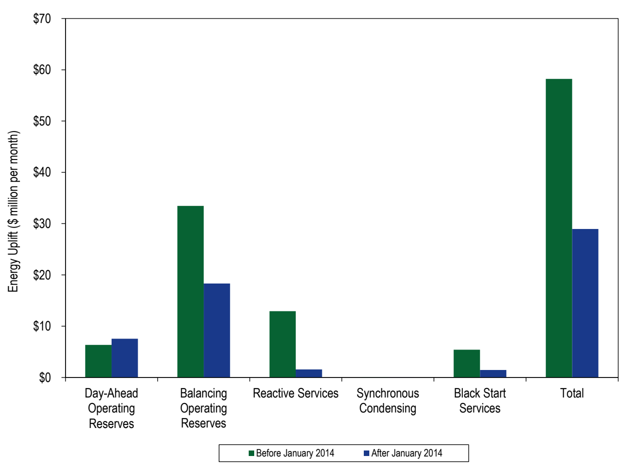
Table 4-40 shows the timeline of these factors.

Table 4-40 Timeline of main factors that reduced energy uplift from 2011 through 2015

Factor / Action	Implementation Month
Black Start / Reactive Commitment Improvement	Sep-12
Closed Loop Interfaces	Jan-13
CT Commitment Improvement	Mar-13
FMU Adders Reduction and Reactive Commitment Improvement	Dec-13
FMU Adders Reform	Oct-14
Price Setting Logic	Nov-14
ALR Units Replacement Completed	May-15
LOC Calculation Reform	Sep-15

Figure 4-9 shows the change in total energy uplift and by energy uplift category from January 2011 through December 2013, to February 2014 through December 2015. The reduction in monthly uplift was comprised of a reduction of $15.1 million per month in balancing operating reserve, a reduction of $11.4 million per month in reactive services, a reduction of $3.9 million per month in black start services and an increase of $1.2 million per month in day-ahead operating reserves.

Figure 4-9 Energy uplift charges from January 2011 through December 2013 and from February 2014 through December 2015 ($million per month)



After January 2014, energy uplift payments to units providing reactive support averaged $1.6 million per month, $11.4 million lower than the average before January 2014. The reduction in energy uplift payments to units providing reactive support resulted from reduced FMU adders and improvement in reactive unit commitment. In addition, the completion of transmission upgrades that had required the use of units for reactive support eliminated the associated energy uplift payments.

After January 2014, energy uplift payments to units providing black start support averaged $1.5 million per month, $3.9 million lower than the average before January 2014. The reduction in energy uplift payments to units providing black start support resulted from the replacement of the ALR black start units.

After January 2014, balancing operating reserves averaged $18.3 million per month, $15.1 million lower than the average before January 2014. Balancing operating reserves are comprised primarily of make whole payments in the balancing market and lost opportunity cost payments.

After January 2014, balancing operating reserve payments (make whole) averaged $11.1 million per month, $9.8 million lower than the average before January 2014. The reduction in balancing operating reserve make whole payments was primarily the result of lower gas prices and the resultant reduction in payments to gas-fired units in the Eastern Region of PJM.

After January 2014, balancing operating reserves (lost opportunity cost) averaged $7.2 million per month, $5.3 million lower than the average before January 2014. The reduction in LOC payments was the result of improvements to the CT commitment process, LOC calculation reform and lower summer peak loads.

After January 2014, day-ahead operating reserves averaged $7.6 million per month, $1.2 million higher than the average before January 2014. The increase in day-ahead operating reserves was the result of payments to coal-fired units that were previously made whole through reactive services credits.