Operating Reserve

Day-ahead and real-time operating reserve credits are 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. Sometimes referred to as uplift or make whole, 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.

Overview

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges in 2012 were $648.7 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 25.6 percent, the balancing operating reserve charges proportion was 66.4 percent, the reactive services charges proportion was 8.0 percent and the synchronous condensing charges proportion was 0.02 percent.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.2001 per MWh, the balancing operating reserve reliability rates averaged $0.0245, $0.0219 and $0.1154 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $0.8147, $0.3332 and $0.1265 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $1.3223 per MWh and canceled resources rate averaged $0.0235 per MWh.

- **Operating Reserve Credits.** Four operating reserve categories accounted for 97.8 percent of all operating reserve credits. Balancing generator operating reserves were 35.1 percent, lost opportunity cost were 29.5 percent, day-ahead generator operating reserves were 25.6 percent and reactive services were 7.6 percent of all credits.

Characteristics of Credits

- **Types of units.** Coal units received 74.3 percent of all day-ahead generator credits and 48.5 percent of all balancing generator credits. Wind units received 94.6 percent of all canceled resources credits. Combustion turbines and diesels received 87.3 percent of the lost opportunity cost credits. Combined cycles and coal units received 80.1 percent of all reactive services credits.

- **Economic – Noneconomic Generation.** In 2012, 84.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In 2012, 83.3 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 5.8 percent by transactions at hubs and 10.9 percent by transactions at interfaces.

- Generators in the Eastern Region paid 11.5 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 49.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 12.3 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 50.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 13.3 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.9 percent of all credits.

Load Response Resource Operating Reserves

- In 2012, 96.4 percent of the total energy revenues for end use customers for providing demand reductions as part of the Economic Load Response Program was paid as economic load response credits. The remaining 3.6 percent was operating reserve credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 22.7 percent of all credits. The top 10 organizations received 81.7 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 3720, balancing operating reserves was 3105 and lost opportunity cost HHI was 4169.
- **Day-Ahead Unit Commitment for Reliability:** On September 13, 2012, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were regularly needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process for combustion turbines in real time. The increase in day ahead scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Market. The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. FERC accepted proposed revisions to PJM's tariff and operating agreement to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes.
- **Lost Opportunity Cost Credits:** In 2012, lost opportunity cost credits increased by $18.8 million compared to 2011. In 2012, the top three control zones receiving lost opportunity cost credits, AP, ComEd and Dominion combined for 64.4 percent of all lost opportunity cost credits, 60.3 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 65.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.5 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Lost Opportunity Cost Calculation:** In 2012, lost opportunity cost credits would have been reduced by $60.8 million, or 31.8 percent, if all changes proposed by the MMU had been implemented.
- **Wind Units Lost Opportunity Cost:** In 2012, lost opportunity cost credits paid to wind units would have been reduced by $3.1 million, or 65.6 percent, if all changes proposed by the MMU had been implemented.
- **Black Start and Voltage Support Units:** Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. The MMU raised the issue that such costs should be categorized as black start costs rather than operating reserve charges. This issue was resolved in PJM's tariff and operating agreement filing with FERC.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Up-to Congestion Transactions:** Up-to congestion transactions do not pay operating reserve charges despite that they affect dispatch and commitment in the Day-Ahead Energy Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant. For example, in 2012, the RTO deviation rate would have been reduced by 59.3 percent if up-to congestion transactions had been included in the calculation of operating reserve charges.

Conclusion

Day-ahead and real-time operating reserve credits are 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. Sometimes referred to as uplift or make whole, 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.

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

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 operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits 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.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves.

The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommends that the allocation of operating reserve charges to participants be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

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

Description of Operating Reserves

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the LMP, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits 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, startup and no-load offers. PJM continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

Credits and Charges Categories

Operating reserve credits include day-ahead and balancing operating reserves, reactive services and synchronous condensing categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 and Table 3-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 3-1 Day-ahead and balancing operating reserve credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
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
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability Balancing Operating Reserve for Deviations Balancing Local Constraint	Real-Time Load plus Export Transactions Real-Time Deviations from Day-Ahead Schedule Applicable Requesting Party	in RTO, Eastern or Western Region
Canceled Resources Lost Opportunity Cost Real-Time Import Transactions Resources Performing Annual Scheduled Black Start Tests Resources Providing Quick Start Reserve	Balancing Operating Reserve Startup Cancellation Balancing Operating Reserve Lost Opportunity Cost Balancing Operating Reserve Transaction Balancing Operating Reserve Generator Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	in RTO Region
Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Real-Time Deviations from Day-Ahead Schedule by RTO, Eastern or Western Region	in RTO, Eastern/ Western Region

Table 3-2 Reactive services and synchronous condensing credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:
		Reactive		
Resources Providing Reactive Service	Reactive Services Generator Reactive Services Lost Opportunity Cost Reactive Services Condensing Reactive Services Condensing Lost Opportunity Cost	→	Reactive Services Charge Reactive Services Local Constraint	Zonal Real-Time Load Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing Lost Opportunity Cost	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions

Day-Ahead Operating Reserves

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

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports.

Balancing Operating Reserves

Balancing operating reserve credits consist of make whole and lost opportunity cost payments in the balancing market. Balancing operating reserve credits are paid to generators, import transactions and load response that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced or suspended at PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if the real-time LMP at the import pricing point is less than the price specified in the transaction, the market participant is made whole. Balancing operating reserve credits are also paid to resources when canceled before coming online, to resources performing annual, scheduled black start tests and to resources providing quick start reserve.

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

Reactive Services

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

Synchronous Condensing

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[1]

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

Balancing Operating Reserve Cost Allocation

Table 3-3 Balancing operating reserve cost allocation process

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

1 "Manual 28: Operating Agreement Accounting," Revision 50 (January 1, 2012).

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

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

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

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

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

Determinants and Deviation Categories

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of control zones, hubs and interfaces. Table 3-4 shows the composition of the Eastern and Western balancing operating reserve regions.

Table 3-4 Balancing operating reserve regions[2]

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

Credits paid to generators defined to be operating for reliability purposes are charged to real-time load and exports, credits paid to generators and import transactions defined to be operating to control deviations on the system, paid for energy lost opportunity credits and paid to resources canceled before coming online are charged to deviations. Table 3-5 shows the different types of deviations.

2 Only two hubs include buses in both the eastern and western regions: the Dominion Hub and the Western Interface Hub.

Table 3-5 Operating reserve deviations

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

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

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

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

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

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

Operating Reserve Results

Operating Reserve Charges

Table 3-6 shows total operating reserve charges from 1999 to 2012.[3] Total operating reserve charges increased by 7.6 percent in 2012 compared to 2011, to a total of $648.7 million.

3 Table 3-6 includes all categories of charges as defined in Table 3-1 and Table 3-2 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 operating reserves. The billing data reflected in this report were current on January 7, 2013.

Table 3-6 Total operating reserve charges: 1999 through 2012[4]

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing
1999	$133,897,428	NA	7.5%
2000	$216,985,147	62.1%	9.6%
2001	$284,046,709	30.9%	8.5%
2002	$273,718,553	(3.6%)	5.8%
2003	$376,491,514	37.5%	5.4%
2004	$537,587,821	42.8%	6.2%
2005	$712,601,789	32.6%	3.1%
2006	$365,572,034	(48.7%)	1.7%
2007	$503,279,869	37.7%	1.6%
2008	$474,268,500	(5.8%)	1.4%
2009	$322,729,996	(32.0%)	1.2%
2010	$622,843,365	93.0%	1.8%
2011	$603,164,922	(3.2%)	1.7%
2012	$648,728,097	7.6%	2.2%

Total operating reserve charges in 2012 were $648.7 million, up from the total of $603.2 million in 2011. Table 3-7 compares monthly operating reserve charges by category for 2011 and 2012. The increase of 7.6 percent in 2012 is comprised of a 90.2 percent increase in day-ahead operating reserve charges, a 9.2 percent decrease in balancing operating reserve charges, a 27.5 percent increase in reactive services charges and an 82.9 percent decrease in synchronous condensing charges.

Table 3-8 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions and day-ahead operating reserve charges for load response. The increase of $78.8 million in day-ahead operating reserve charges was primarily a result of PJM scheduling units for reliability purposes in the Day-Ahead Energy Market in order to reduce divergence between the scheduled resources in the Day-Ahead Energy Market and the actual resources operating in the Real-Time Energy Market.

Table 3-9 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for load response and balancing local constraint charges. In 2012, balancing operating reserve deviation charges accounted for 80.6 percent of all balancing operating reserve charges, 0.3 percentage points higher compared to the 2011 share.

Table 3-7 Monthly operating reserve charges: 2011 and 2012[5]

	2011					2012				
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Total
Jan	$12,373,210	$47,091,369	$1,546,278	$110,095	$61,120,952	$8,311,574	$27,341,331	$2,934,337	$27,037	$38,614,279
Feb	$8,940,203	$26,607,792	$1,918,076	$140,145	$37,606,217	$5,858,308	$24,877,526	$13,108,017	$18,592	$43,862,444
Mar	$6,837,719	$23,238,170	$1,438,306	$67,337	$31,581,532	$3,852,873	$29,758,387	$6,731,994	$1,648	$40,344,903
Apr	$4,405,102	$18,782,050	$2,077,101	$39,599	$25,303,852	$2,967,302	$34,168,706	$4,521,280	$0	$41,657,289
May	$7,064,934	$43,670,945	$2,712,293	$61,801	$53,509,973	$7,956,965	$43,697,911	$5,392,428	$0	$57,047,304
Jun	$8,304,092	$59,889,850	$1,868,004	$19,118	$70,081,063	$6,974,418	$45,694,198	$5,133,009	$0	$57,801,625
Jul	$4,993,311	$103,271,978	$929,808	$281,186	$109,476,283	$11,774,314	$66,578,369	$2,960,922	$0	$81,313,605
Aug	$8,360,392	$53,820,132	$1,696,735	$104,982	$63,982,240	$8,703,915	$47,577,859	$4,112,186	$0	$60,393,960
Sep	$6,249,240	$35,297,398	$2,713,004	$44,882	$44,304,524	$28,882,469	$32,732,917	$4,458,891	$24,366	$66,098,643
Oct	$5,133,837	$18,132,328	$15,523,789	$0	$38,789,953	$22,588,209	$26,181,268	$1,253,642	$38,762	$50,061,881
Nov	$7,063,847	$19,754,264	$6,758,644	$0	$33,576,755	$18,077,440	$24,349,681	$120,820	$0	$42,547,941
Dec	$7,593,046	$24,793,125	$1,445,408	$0	$33,831,578	$40,123,845	$27,761,191	$1,061,343	$37,845	$68,984,223
Total	$87,318,931	$474,349,400	$40,627,447	$869,144	$603,164,922	$166,071,633	$430,719,346	$51,788,868	$148,250	$648,728,097
Share of Charges	14.5%	78.6%	6.7%	0.1%	100.0%	25.6%	66.4%	8.0%	0.0%	100.0%

4 The total operating reserve charges in Table 3-6 are different than the total charges published in the *2011 State of the Market Report for PJM* and previous versions because previous versions did not include operating reserve charges for load response nor reactive services charges. PJM may recalculate new settlements after the State of the Market Report is published.

5 Table 3-7 and subsequent tables do not reflect the changes in day-ahead operating reserve charges and reactive services charges for December 2012. The change in the allocation of day-ahead operating reserve charges for black start and reactive services was approved by FERC (ER13-481-000) on January 28, 2013 with an effective date of December 1, 2012.

Table 3-8 Day-ahead operating reserve charges: 2011 and 2012

Type	2011	2012	Change	2011 Share	2012 Share
Day-Ahead Operating Reserve Charges	$87,318,120	$166,053,573	$78,735,453	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$811	$18,060	$17,248	0.0%	0.0%
Total	$87,318,931	$166,071,633	$78,752,701	100.0%	100.0%

Table 3-9 Balancing operating reserve charges: 2011 and 2012

Type	2011	2012	Change	2011 Share	2012 Share
Balancing Operating Reserve Reliability Charges	$90,706,786	$75,718,815	($14,987,971)	19.1%	17.6%
Balancing Operating Reserve Deviation Charges	$380,851,385	$347,024,111	($33,827,274)	80.3%	80.6%
Balancing Operating Reserve Charges for Load Response	$162,673	$319,719	$157,046	0.0%	0.1%
Balancing Local Constraint Charges	$2,628,556	$7,656,701	$5,028,145	0.6%	1.8%
Total	$474,349,400	$430,719,346	($43,630,054)	100.0%	100.0%

Table 3-10 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In 2012, 55.1 percent of all balancing operating reserve deviation charges were attributable to energy lost opportunity cost, an increase of 9.8 percentage points compared to the 2011 share.

Table 3-10 Balancing operating reserve deviation charges: 2011 and 2012

Charge attributable to	2011	2012	Change	2011 Share	2012 Share
Make Whole Payments to Generators and Imports	$198,418,376	$152,411,105	($46,007,271)	52.1%	43.9%
Energy Lost Opportunity Cost	$172,412,292	$191,212,934	$18,800,642	45.3%	55.1%
Canceled Resources	$10,020,716	$3,400,071	($6,620,645)	2.6%	1.0%
Total	$380,851,385	$347,024,111	($33,827,274)	100.0%	100.0%

Table 3-11 shows the composition of the reactive services charges. Reactive services charges consist of reactive services charges attributable to make whole payments and lost opportunity cost payments to generators that run at PJM's request, plus reactive services local constraint charges attributable to generators requested by a third party to provide the service.

Table 3-11 Reactive services charges: 2011 and 2012

Type	2011	2012	Change	2011 Share	2012 Share
Reactive Services Charges	$40,627,447	$51,751,602	$11,124,155	100.0%	99.9%
Reactive Services Local Constraint Charges	$0	$37,266	$37,266	0.0%	0.1%
Total	$40,627,447	$51,788,868	$11,161,421	100.0%	100.0%

Table 3-12 and Table 3-13 show the amount and percentages of regional balancing charges allocation for 2011 and 2012. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges, since these charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints, resources providing quick start reserve and resources performing annual, scheduled black start tests.

In 2012, regional balancing operating reserve charges decreased by $48.8 million compared to 2011. Balancing operating reserve reliability charges decreased by $15.0 million or 16.5 percent and balancing reserve deviation charges decreased by $33.8 million or 8.9 percent. In 2012, reliability charges in the Western Region increased by $19.5 million compared to 2011, as a result of payments to units providing black start and voltage support. The remaining two reliability categories decreased by $34.5 million.

Table 3-12 Regional balancing charges allocation: 2011

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$49,430,917	10.5%	$9,996,503	2.1%	$27,029,730	5.7%	$86,457,149	18.3%
	Real-Time Exports	$2,032,752	0.4%	$589,969	0.1%	$1,626,917	0.3%	$4,249,637	0.9%
	Total	$51,463,668	10.9%	$10,586,472	2.2%	$28,656,646	6.1%	$90,706,786	19.2%
Deviation Charges	Demand	$205,564,297	43.6%	$25,067,477	5.3%	$4,385,476	0.9%	$235,017,249	49.8%
	Supply	$60,333,400	12.8%	$6,643,500	1.4%	$1,514,331	0.3%	$68,491,231	14.5%
	Generator	$69,165,480	14.7%	$6,216,435	1.3%	$1,960,990	0.4%	$77,342,904	16.4%
	Total	$335,063,177	71.1%	$37,927,411	8.0%	$7,860,797	1.7%	$380,851,385	80.8%
Total Regional Balancing Charges		$386,526,845	82.0%	$48,513,882	10.3%	$36,517,443	7.7%	$471,558,171	100%

Table 3-13 Regional balancing charges allocation: 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18,780,592	4.4%	$8,012,210	1.9%	$46,269,752	10.9%	$73,062,554	17.3%
	Real-Time Exports	$593,505	0.1%	$169,755	0.0%	$1,893,001	0.4%	$2,656,261	0.6%
	Total	$19,374,097	4.6%	$8,181,965	1.9%	$48,162,753	11.4%	$75,718,815	17.9%
Deviation Charges	Demand	$185,471,316	43.9%	$16,507,163	3.9%	$4,744,936	1.1%	$206,723,416	48.9%
	Supply	$55,888,314	13.2%	$4,579,717	1.1%	$1,255,728	0.3%	$61,723,759	14.6%
	Generator	$71,072,646	16.8%	$5,260,437	1.2%	$2,243,853	0.5%	$78,576,936	18.6%
	Total	$312,432,277	73.9%	$26,347,318	6.2%	$8,244,516	2.0%	$347,024,111	82.1%
Total Regional Balancing Charges		$331,806,374	78.5%	$34,529,283	8.2%	$56,407,269	13.3%	$422,742,926	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 3-1 for how these charges are allocated.[6]

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for 2011 and 2012. The average rate in 2012 was $0.2001 per MWh, $0.0933 per MWh higher than the average in 2011. The highest rate occurred on October 30, when the rate reached $1.0997 per MWh, 140.4 percent higher than the $0.4574 per MWh reached during 2011, on August 27. On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market.[7]

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): 2011 and 2012

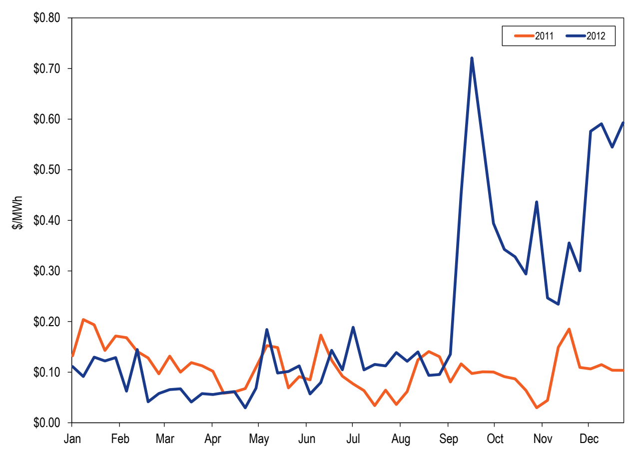


Figure 3-2 shows the RTO and the regional reliability rates for 2011 and 2012. The average daily RTO reliability rate was $0.0245 per MWh. The highest RTO reliability rate of 2012 occurred on July 18, when the rate reached $0.3160 per MWh. In 2012, reliability rates in the Eastern Region were positive for only 32 days. Hot weather related demand in the entire RTO and specifically in the Dominion control zone led to the top three Eastern Region reliability rates in 2012, on July 1, 19 and 27, the Eastern Region reliability rate reached $1.6869, $1.0099 and $1.4847 per MWh.[8] Reliability rates in the Western Region have been high primarily

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

7 See "Day-Ahead Unit Commitment for Reliability" on "Operating Reserve Issues" of this section for further details on the September 13 day-ahead scheduling process change.

8 PJM issued consecutive Hot Weather Alerts for the entire RTO region for June 20 and June 21, and for June 28 through July 7, for the Dominion and Mid-Atlantic zones for June 22 and July 27 and for the Dominion zone only on July 19.

because of the use of certain units to provide black start and voltage support.

Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): 2011 and 2012

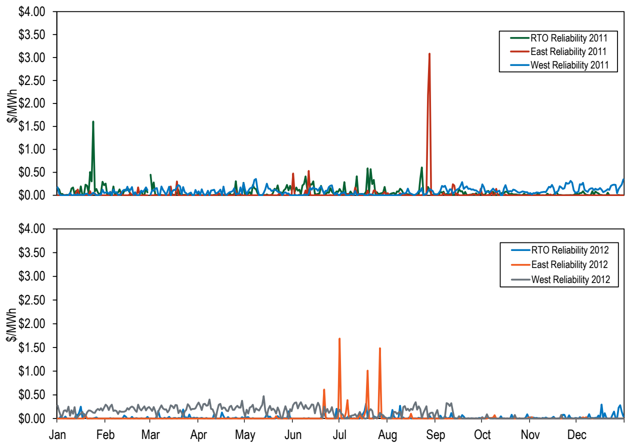


Figure 3-3 shows the RTO and the regional deviation rates for 2011 and 2012. The average daily RTO deviation rate was $0.8147 per MWh. The highest daily rate in 2012 occurred on July 26, when the RTO deviation rate reached $3.7260 per MWh.[9] The highest Eastern Region rate occurred on December 31, when a combination of transmission constraints in central and northeastern New Jersey and higher natural gas prices caused the Eastern Region rate to increase during the last days of December. Three of the top four rates occurred on the last three days of the year.[10] The Western Region deviation rate increase on April 12 was due to the loss of a 345 kV transmission line in the Pittsburgh area.

Figure 3-3 Daily balancing operating reserve deviation rates ($/MWh): 2011 and 2012

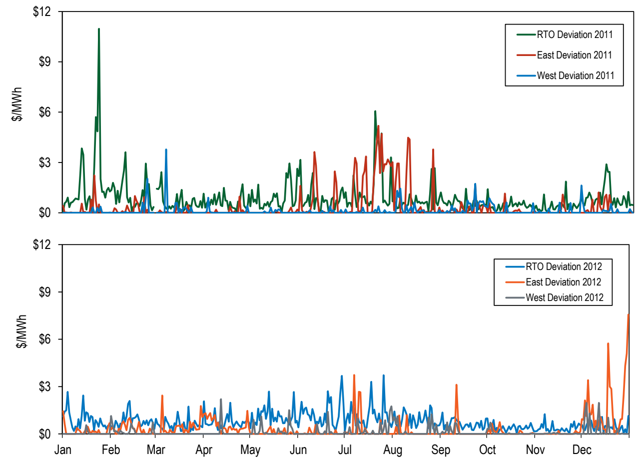
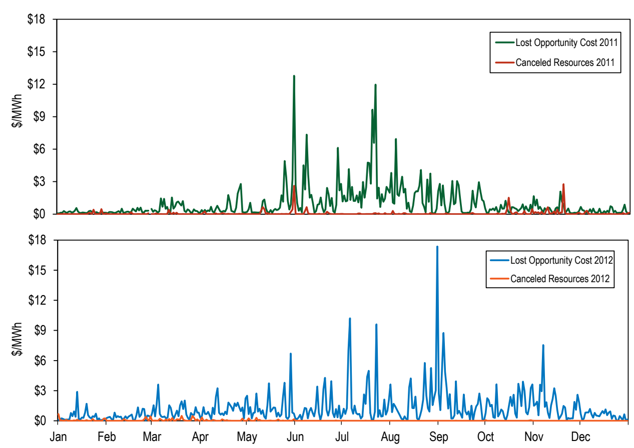


Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2011 and 2012. The lost opportunity rate averaged $1.3223 per MWh. The highest lost opportunity cost rate occurred on August 31, when it reached $17.3678 per MWh. Increases in the lost opportunity rate are often caused by high real-time prices which increases the total lost opportunity cost credits paid to combustion turbines scheduled to run but not called in real time. The canceled resources rate averaged $0.0235 per MWh and credits were paid during 29.5 percent of all the days in 2012.

Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2011 and 2012



9 The June 29, 2012, RTO deviation rate ($3.9347 per MWh) published in the *2012 Quarterly State of the Market Report for PJM: January through June* was higher than the July 26 rate, but the former was recalculated by PJM and resulted in a lower rate ($3.6802 per MWh).

10 Transco Zone 6 NY natural gas price index increased 313.1 percent from December 25 to December 31, 2012.

Table 3-14 shows the average rates for each region in each category for 2011 and 2012.

Table 3-14 Operating reserve rates ($/MWh): 2011 and 2012

Rate	2011 ($/MWh)	2012 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.107	0.200	0.093	87.4%
RTO Reliability	0.068	0.024	(0.044)	(64.0%)
East Reliability	0.027	0.022	(0.006)	(20.2%)
West Reliability	0.078	0.115	0.038	48.9%
RTO Deviation	0.947	0.815	(0.132)	(13.9%)
East Deviation	0.423	0.333	(0.090)	(21.3%)
West Deviation	0.111	0.126	0.016	14.4%
Lost Opportunity Cost	1.069	1.322	0.253	23.7%
Canceled Resources	0.062	0.024	(0.039)	(62.2%)

Table 3-15 shows the operating reserve cost of a 1 MW transaction during 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.5908 per MWh with a maximum rate of $17.9643 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $1.8025 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges. Table 3-15 illustrates both the average level of operating reserve charges to transaction types but also the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 3-15 Operating reserve rates statistics ($/MWh): 2012

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.920	2.384	0.203	1.817
	DEC	17.964	2.591	0.470	1.802
	DA Load	1.100	0.206	0.000	0.204
	RT Load	1.690	0.040	0.000	0.144
	Deviation	17.920	2.384	0.203	1.817
West	INC	17.920	2.168	0.034	1.791
	DEC	17.964	2.375	0.409	1.760
	DA Load	1.100	0.206	0.000	0.204
	RT Load	0.473	0.142	0.000	0.110
	Deviation	17.920	2.168	0.034	1.791

Operating Reserve Determinants

Table 3-16 shows the determinants used to allocate the regional balancing operating reserve charges for 2011 and 2012. Total real-time load and real-time exports were 35,308,679 MWh or 4.7 percent higher in 2012 compared to 2011. Total deviations summed across the demand, supply, and generator categories were lower in 2012 compared to 2011 by 16,625,857 MWh or 10.3 percent.

Table 3-16 Balancing operating reserve determinants (MWh): 2011 and 2012

		Reliability Charge Determinants			Deviation Charge Determinants			
		Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2011	RTO	722,863,726	32,677,889	755,541,614	97,202,373	30,280,081	33,753,732	161,236,185
	East	371,881,388	13,907,374	385,788,761	57,598,072	16,595,295	15,408,788	89,602,154
	West	350,982,338	18,770,515	369,752,853	39,199,351	13,557,237	18,344,944	71,101,532
2012	RTO	764,248,367	26,601,926	790,850,293	85,045,723	26,275,437	33,289,168	144,610,329
	East	362,985,584	10,425,635	373,411,219	48,968,172	14,730,038	15,374,913	79,073,124
	West	401,262,783	16,176,291	417,439,074	35,792,061	11,477,683	17,914,255	65,183,999
Difference	RTO	41,384,641	(6,075,963)	35,308,679	(12,156,650)	(4,004,644)	(464,563)	(16,625,857)
	East	(8,895,803)	(3,481,739)	(12,377,542)	(8,629,900)	(1,865,256)	(33,875)	(10,529,031)
	West	50,280,445	(2,594,224)	47,686,221	(3,407,291)	(2,079,554)	(430,689)	(5,917,534)

Operating Reserve Credits

Table 3-17 shows the totals for each credit category for 2011 and 2012. During 2012, 66.4 percent of total operating reserve credits were in the balancing category. This percentage decreased 12.2 percentage points from the 78.6 percent in 2011.

Table 3-17 Credits by operating reserve category: 2011 and 2012

Category	Type	2011	2012	Change	Percentage Change	2011 Share	2012 Share
Day-Ahead	Generators	$87,007,258	$166,053,019	$79,045,761	90.8%	14.4%	25.6%
	Imports	$310,864	$554	($310,310)	(99.8%)	0.1%	0.0%
	Load Response	$811	$18,059	$17,248	2,126.4%	0.0%	0.0%
Balancing	Canceled Resources	$10,020,718	$3,400,074	($6,620,644)	(66.1%)	1.7%	0.5%
	Generators	$287,360,286	$227,970,357	($59,389,929)	(20.7%)	47.6%	35.1%
	Imports	$1,764,877	$159,564	($1,605,313)	(91.0%)	0.3%	0.0%
	Load Response	$162,675	$319,580	$156,904	96.5%	0.0%	0.0%
	Local Constraints Control	$2,628,556	$7,656,701	$5,028,145	191.3%	0.4%	1.2%
	Lost Opportunity Cost	$172,412,291	$191,212,932	$18,800,641	10.9%	28.6%	29.5%
Reactive Services	Local Constraints Control	$0	$37,266	$37,266	NA	0.0%	0.0%
	Lost Opportunity Cost	$2,916,878	$2,466,590	($450,288)	(15.4%)	0.5%	0.4%
	Reactive Services	$37,584,680	$49,138,977	$11,554,297	30.7%	6.2%	7.6%
	Synchronous Condensing	$125,888	$146,035	$20,147	16.0%	0.0%	0.0%
Synchronous Condensing		$869,144	$148,250	($720,894)	(82.9%)	0.1%	0.0%
Total		$603,164,928	$648,727,959	$45,563,032	7.6%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-18 shows the distribution of total operating reserve credits by unit type for 2012. The reduction of the price spread between natural gas and coal prices resulted in an increase in operating reserve credits paid to coal units. In 2012, 43.8 percent of all operating reserve credits paid to units were paid to coal units, 19.1 percentage points more than the share in 2011. In contrast, the share of total credits paid to gas fired combined cycles declined from 19.4 percent in 2011 to 12.2 percent in 2012.

Table 3-18 Operating reserve credits by unit type: 2011 and 2012

Unit Type	2011	2012	Change	Percentage Change	2011 Share of Credits	2012 Share of Credits
Battery	$12,488	$0	($12,488)	(100.0%)	0.0%	0.0%
Combined Cycle	$116,542,789	$79,111,224	($37,431,565)	(32.1%)	19.4%	12.2%
Combustion Turbine	$233,626,148	$227,502,167	($6,123,981)	(2.6%)	38.9%	35.1%
Diesel	$20,173,863	$3,615,243	($16,558,619)	(82.1%)	3.4%	0.6%
Fuel Cell	$307,331	$0	($307,331)	(100.0%)	0.1%	0.0%
Hydro	$431,172	$294,991	($136,181)	(31.6%)	0.1%	0.0%
Nuclear	$0	$1,655,968	$1,655,968	0.0%	0.0%	0.3%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$148,474,069	$283,922,818	$135,448,749	91.2%	24.7%	43.8%
Steam - Other	$72,160,635	$44,215,846	($27,944,788)	(38.7%)	12.0%	6.8%
Wind	$9,197,206	$7,911,944	($1,285,261)	(14.0%)	1.5%	1.2%
Total	$600,925,700	$648,230,202	$47,304,502	7.9%	100.0%	100.0%

Table 3-19 shows the distribution of day-ahead and balancing operating reserve credits by unit type in 2012. Coal units received 74.3 percent of the day-ahead generator credits in 2012, 22.1 percentage points higher than the share received in 2011. Coal units received 48.5 percent of the balancing generator credits in 2012, 23.6 percentage points higher than the share received in 2011. Wind units received 94.6 percent of the canceled resources credits in 2012, 2.8 percentage points higher than the share received in 2011. Combustion turbines and diesels received 87.3 percent of the lost opportunity cost credits, 0.6 percentage points higher than the share received in 2011.

Table 3-19 Operating reserve credits by unit type: 2012

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	13.2%	18.0%	2.0%	0.1%	4.1%	15.9%	0.0%
Combustion Turbine	4.4%	20.1%	2.7%	4.3%	86.6%	15.7%	100.0%
Diesel	0.0%	0.6%	0.0%	0.0%	0.6%	2.1%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.1%	0.8%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	74.3%	48.5%	0.0%	95.5%	4.9%	64.2%	0.0%
Steam - Others	8.1%	12.7%	0.0%	0.1%	0.4%	2.0%	0.0%
Wind	0.0%	0.0%	94.6%	0.0%	2.4%	0.0%	0.0%
Total	$166,053,019	$227,970,357	$3,400,074	$7,656,701	$191,212,932	$51,788,868	$148,250

Table 3-19 also shows the distribution of reactive service credits and synchronous condensing by unit type. In 2012, combined cycle and coal units received 80.1 percent of all reactive services credits, 37.6 percentage points higher than the share received in 2011. In contrast, combustion turbines received 15.7 percent in 2012, 36.7 percentage points lower than the share received in 2011. Synchronous condensing was only provided by combustion turbines.

Wind Unit Credits

On June 1, 2012, PJM began to correctly categorize credits paid to wind units for lost opportunity cost and not as canceled resources credits. Also on June 1, 2012, PJM implemented new lost opportunity cost credit rules for wind units. Under the new rules, lost opportunity cost credits paid to wind units are based on the lesser of the LMP desired output and the forecasted output of the unit.[11]

Credits paid to wind units decreased in 2012. In 2012, the total was $7.9 million, lower than the $9.2 million paid in 2011. Table 3-20 shows the monthly credits paid to wind units.

11 See "PJM Manual 28: Operating Agreement Accounting" Revision 56 (October 1, 2012), Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons.

Table 3-20 Operating reserve credits paid to wind units: 2011 and 2012

	2011				2012			
	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Total	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Total
Jan	$0	$468,059	$0	$468,059	$0	$741,979	$0	$741,979
Feb	$0	$182,151	$0	$182,151	$0	$517,612	$0	$517,612
Mar	$0	$344,622	$0	$344,622	$0	$1,098,130	$72	$1,098,202
Apr	$0	$271,810	$0	$271,810	$20,990	$409,047	$0	$430,038
May	$0	$2,446,129	$0	$2,446,129	$23,212	$448,836	$0	$472,048
Jun	$0	$839,074	$0	$839,074	$817	$0	$119,146	$119,963
Jul	$0	$167,310	$0	$167,310	$129	$0	$63,805	$63,934
Aug	$0	$244,935	$0	$244,935	$0	$0	$175,321	$175,321
Sep	$0	$151,194	$0	$151,194	$683	$0	$834,466	$835,149
Oct	$0	$1,325,128	$0	$1,325,128	$229	$0	$2,799,801	$2,800,030
Nov	$0	$2,336,582	$0	$2,336,582	$0	$0	$215,730	$215,730
Dec	$0	$420,210	$0	$420,210	$503	$0	$441,436	$441,938
Total	$0	$9,197,206	$0	$9,197,206	$46,562	$3,215,605	$4,649,777	$7,911,944

The AEP, AP, ComEd and PENELEC Control Zones are the only zones with wind units receiving operating reserve credits.

Economic and Noneconomic Generation[12]

Economic dispatch 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 3-21 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 economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based solely 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 additional hourly no load and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits because total energy revenues covered total hourly costs. In 2012, 34.5 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 32.3 percent of the real-time generation was eligible for balancing operating reserve credits.

Table 3-21 Day-ahead and real-time generation (GWh): 2012

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	798,561	275,368	34.5%
Real-Time	790,090	255,489	32.3%

Table 3-22 shows PJM's economic and noneconomic generation eligible for operating reserve credits. In 2012, 84.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

12 The analysis of economic and noneconomic generation in previous *State of the Market Reports for PJM* was based on the relationship between the units' hourly average incremental offer and the LMP at the units' bus. The new analysis is based on the units' incremental offer, the value used by PJM to calculate LMP. Neither analysis includes no load or startup cost.

Table 3-22 Day-ahead and real-time economic and noneconomic generation (GWh): 2012

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	231,880	43,488	84.2%	15.8%
Real-Time	170,886	84,603	66.9%	33.1%

Table 3-23 shows the generation receiving day-ahead and balancing operating reserve credits. In 2012, 8.6 percent of the day-ahead generation eligible for operating reserve credits was made whole and 8.9 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 3-23 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2012

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	275,368	23,753	8.6%
Real-Time	255,489	22,810	8.9%

Geography of Charges and Credits

Table 3-24 shows the geography of charges and credits in 2012. Table 3-24 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 and synchronous condensing are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub 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, the transactions in the AEP Control Zone paid 13.0 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 18.5 percent of the corresponding credits. The AEP Control Zone received more operating reserve credits than operating reserve charges paid. The JCPL Control Zone received fewer operating reserve credits than operating reserve charges paid. Table 3-24 also shows that 83.3 percent of all charges were allocated in control zones, 5.8 percent in hubs and 10.9 percent in interfaces.

Table 3-25 and Table 3-26 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table 3-25 shows that on average, 11.5 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 49.4 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-26 also shows that generators in the Western Region paid 12.3 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 50.5 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-24 Geography of regional charges and credits: 2012[13]

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$6,949,637	$5,214,973	($1,734,663)	1.2%	0.9%	0.9%	0.0%
	AEP	$76,374,859	$108,712,796	$32,337,937	13.0%	18.5%	0.0%	16.3%
	AP - DLCO	$45,365,789	$44,074,231	($1,291,559)	7.7%	7.5%	0.7%	0.0%
	ATSI	$36,554,526	$56,654,867	$20,100,341	6.2%	9.6%	0.0%	10.2%
	BGE - Pepco	$45,732,823	$100,073,174	$54,340,351	7.8%	17.0%	0.0%	27.4%
	ComEd - External	$73,457,999	$47,580,426	($25,877,573)	12.5%	8.1%	13.1%	0.0%
	DAY - DEOK	$27,561,044	$3,942,821	($23,618,224)	4.7%	0.7%	11.9%	0.0%
	Dominion	$42,165,186	$77,116,238	$34,951,052	7.2%	13.1%	0.0%	17.7%
	DPL	$13,615,194	$29,592,687	$15,977,492	2.3%	5.0%	0.0%	8.1%
	JCPL	$14,585,407	$10,546,598	($4,038,809)	2.5%	1.8%	2.0%	0.0%
	Met-Ed	$10,542,326	$3,911,509	($6,630,818)	1.8%	0.7%	3.3%	0.0%
	PECO	$26,975,046	$8,368,712	($18,606,334)	4.6%	1.4%	9.4%	0.0%
	PENELEC	$14,057,792	$17,895,187	$3,837,395	2.4%	3.0%	0.0%	1.9%
	PPL	$26,163,671	$9,219,252	($16,944,419)	4.4%	1.6%	8.6%	0.0%
	PSEG	$29,311,290	$65,732,911	$36,421,622	5.0%	11.2%	0.0%	18.4%
	RECO	$928,979	$0	($928,979)	0.2%	0.0%	0.5%	0.0%
	All Zones	$490,341,570	$588,636,382	$98,294,813	83.3%	100.0%	50.3%	100.0%
Hubs	AEP - Dayton	$6,306,595	$0	($6,306,595)	1.1%	0.0%	3.2%	0.0%
	Dominion	$712,977	$0	($712,977)	0.1%	0.0%	0.4%	0.0%
	Eastern	$1,147,014	$0	($1,147,014)	0.2%	0.0%	0.6%	0.0%
	New Jersey	$787,511	$0	($787,511)	0.1%	0.0%	0.4%	0.0%
	Ohio	$204,195	$0	($204,195)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$96,917	$0	($96,917)	0.0%	0.0%	0.0%	0.0%
	Western	$24,917,228	$0	($24,917,228)	4.2%	0.0%	12.6%	0.0%
	All Hubs	$34,172,436	$0	($34,172,436)	5.8%	0.0%	17.3%	0.0%
Interfaces	IMO	$9,746,975	$0	($9,746,975)	1.7%	0.0%	4.9%	0.0%
	Linden	$2,022,916	$0	($2,022,916)	0.3%	0.0%	1.0%	0.0%
	MISO	$14,985,788	$0	($14,985,788)	2.5%	0.0%	7.6%	0.0%
	Neptune	$919,748	$0	($919,748)	0.2%	0.0%	0.5%	0.0%
	NIPSCO	$77,651	$0	($77,651)	0.0%	0.0%	0.0%	0.0%
	Northwest	$399,144	$0	($399,144)	0.1%	0.0%	0.2%	0.0%
	NYIS	$5,793,997	$0	($5,793,997)	1.0%	0.0%	2.9%	0.0%
	OVEC	$1,730,224	$0	($1,730,224)	0.3%	0.0%	0.9%	0.0%
	South Exp	$8,613,474	$0	($8,613,474)	1.5%	0.0%	4.4%	0.0%
	South Imp	$19,992,576	$0	($19,992,576)	3.4%	0.0%	10.1%	0.0%
	All Interfaces	$64,282,493	$160,118	($64,122,375)	10.9%	0.0%	32.4%	0.0%
	Total	$588,796,500	$588,796,500	$0	100.0%	100.0%	100.0%	100.0%

Table 3-25 Monthly balancing operating reserve charges and credits to generators (Eastern Region): 2012

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,173,478	$234,258	$562,031	$1,969,766	$14,130,635
Feb	$733,719	$281,274	$433,268	$1,448,262	$9,874,828
Mar	$620,144	$477,947	$1,177,834	$2,275,925	$11,741,895
Apr	$803,236	$546,718	$1,263,975	$2,613,929	$17,370,555
May	$1,363,506	$73,346	$2,010,843	$3,447,695	$20,571,763
Jun	$1,917,833	$65,193	$1,644,883	$3,627,908	$22,401,191
Jul	$1,956,754	$619,582	$3,573,110	$6,149,446	$33,543,351
Aug	$1,196,561	$148,582	$2,962,588	$4,307,731	$23,754,698
Sep	$687,459	$102,742	$2,213,097	$3,003,298	$13,844,352
Oct	$493,377	$131,315	$2,559,682	$3,184,374	$11,949,583
Nov	$583,844	$39,463	$2,356,074	$2,979,381	$10,814,962
Dec	$681,196	$2,540,017	$747,471	$3,968,684	$18,781,651
East Generators Total	$12,211,107	$5,260,437	$21,504,855	$38,976,399	$208,779,464
PJM Total	$117,819,271	$26,347,318	$194,613,006	$338,779,594	$422,742,927
Share	10.4%	20.0%	11.1%	11.5%	49.4%

13 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-24 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.

Table 3-26 Monthly balancing operating reserve charges and credits to generators (Western Region): 2012

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,309,915	$32,410	$787,486	$2,129,811	$12,526,783
Feb	$1,109,193	$282,686	$706,304	$2,098,184	$14,189,145
Mar	$827,049	$0	$1,515,079	$2,342,127	$17,113,158
Apr	$1,072,628	$139,080	$1,712,412	$2,924,120	$15,790,612
May	$1,775,248	$232,625	$2,441,429	$4,449,301	$22,299,111
Jun	$2,123,990	$128,649	$1,781,938	$4,034,577	$21,871,777
Jul	$2,165,687	$393,354	$3,850,796	$6,409,837	$32,185,306
Aug	$1,085,090	$316,063	$2,949,618	$4,350,772	$22,572,480
Sep	$738,362	$142,920	$2,289,074	$3,170,355	$18,572,971
Oct	$583,882	$77,826	$2,492,165	$3,153,874	$14,148,780
Nov	$478,365	$14,384	$1,889,622	$2,382,371	$13,431,833
Dec	$762,977	$483,855	$908,375	$2,155,207	$8,923,484
West Generators Total	$14,032,386	$2,243,853	$23,324,298	$39,600,537	$213,625,441
PJM Total	$117,819,271	$8,244,516	$194,613,006	$320,676,793	$422,742,927
Share	11.9%	27.2%	12.0%	12.3%	50.5%

Table 3-27 shows that on average in 2012, generator charges were 13.3 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 0.8 percentage points lower than the average for 2011. Generators received 99.9 percent of all operating reserve credits, while the remaining 0.1 percent were credits paid to import transactions and load response resources.

Table 3-27 Percentage of unit credits and charges of total credits and charges: 2011 and 2012

	2011		2012	
	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	11.2%	99.2%	11.7%	99.9%
Feb	11.8%	98.7%	11.9%	100.0%
Mar	12.9%	98.6%	14.1%	99.8%
Apr	15.5%	99.0%	15.3%	100.0%
May	16.0%	100.0%	15.5%	100.0%
Jun	13.4%	99.8%	14.9%	99.9%
Jul	16.6%	100.0%	16.2%	99.8%
Aug	14.2%	100.0%	15.7%	99.9%
Sep	13.1%	99.9%	10.1%	100.0%
Oct	11.3%	99.8%	13.0%	99.9%
Nov	12.8%	99.6%	12.6%	99.8%
Dec	11.4%	99.9%	9.0%	100.0%
Average	14.2%	99.6%	13.3%	99.9%

Reactive services charges are allocated by zone. In 2012, the top three zones accounted for 52.2 percent of the total reactive services charges and 62.5 percent of the total reactive services credits costs, a decrease of 23.2 and 21.4 percentage points from the share of the top three zones in 2011. The top three control zones in 2012 were DPL, ATSI and PENELEC.[14]

Synchronous condensing charges are allocated by zone. Two zones accounted for all synchronous condensing costs in 2012.[15]

14 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

15 PJM and the MMU cannot publish more detailed information about the location of the costs of synchronous condensing because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

Load Response Resource Operating Reserves

Load response resources participating in the Economic Load Response Program may receive make whole payments when their energy revenues from the Economic Load Program do not cover their offer plus shutdown costs.[16] These make whole payments are called load response resource operating reserve credits. Load response resources are eligible to receive operating reserve credits if they followed PJM dispatch instruction in real time. Load response resources are considered to be following dispatch if the actual load reduction does not deviate by more than 20 percent from the desired reduction.

Load response resources receive day-ahead operating reserve credits when their revenues are lower than their offer plus shutdown costs and their offer is equal or greater than the threshold price established under the Net Benefits Test. Load response resources are eligible for day-ahead operating reserve credits if they followed PJM dispatch instruction in real time.

In the Balancing Energy Market, the revenues for reducing load are based on the actual MWh reduction in excess of the scheduled day-ahead load reductions plus an adjustment for losses times the real-time LMP. Load response resources receive balancing operating reserve credits when their revenues are lower than their offer plus shutdown costs and their offer is equal or greater than the threshold price established under the Net Benefits Test. Load response resources are eligible for balancing operating reserve credits if they followed PJM dispatch instruction in real time.

In 2012, 96.4 percent of the total energy revenues of end use customers for providing demand reductions as part of the Economic Load Response Program was paid as economic load response credits. The remaining 3.6 percent was made whole through operating reserve credits as shown in Table 3-28.

Table 3-28 Day-ahead and balancing operating reserve for load response credits: 2011 and 2012

	2011				2012			
	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve
Jan	$140,236	$1,111	99.2%	0.8%	$8,711	$19,002	31.4%	68.6%
Feb	$88,599	$0	100.0%	0.0%	$14,994	$7,878	65.6%	34.4%
Mar	$11,469	$0	100.0%	0.0%	$6,749	$56,130	10.7%	89.3%
Apr	$37,533	$17,796	67.8%	32.2%	$195,598	$0	100.0%	0.0%
May	$271,955	$130,162	67.6%	32.4%	$484,756	$0	100.0%	0.0%
Jun	$906,532	$3,932	99.6%	0.4%	$1,454,811	$30,848	97.9%	2.1%
Jul	$379,570	$539	99.9%	0.1%	$3,771,027	$169,955	95.7%	4.3%
Aug	$87,943	$191	99.8%	0.2%	$1,538,545	$35,128	97.8%	2.2%
Sep	$19,670	$0	100.0%	0.0%	$704,712	$13,346	98.1%	1.9%
Oct	$48,863	$857	98.3%	1.7%	$609,844	$29	100.0%	0.0%
Nov	$15,524	$0	100.0%	0.0%	$363,245	$5,319	98.6%	1.4%
Dec	$45,102	$8,898	83.5%	16.5%	$6,437	$4	99.9%	0.1%
Total	$2,052,996	$163,487	92.6%	7.4%	$9,159,429	$337,639	96.4%	3.6%

Operating Reserve Issues

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

16 See Section 5, "Demand Response" at "Emergency Energy Payments" for the make whole payments to load response resources participating in the Emergency Load Response Program.

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

The concentration of operating reserve credits in the top 10 units remains high, but decreased in 2012 compared to 2011. Table 3-29 shows the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 22.7 percent of total operating reserve credits in 2012, compared to 28.1 percent in 2011. The top 20 units received 34.5 percent of total operating reserve credits in 2012.

Table 3-29 Top 10 operating reserve credits units (By percent of total system): 2001 through 2012

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%
2012	22.7%	0.6%

Table 3-30 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories paid to generators. The shares of the top 10 organizations in all categories separately were above 80.0 percent.

Table 3-30 Top 10 units and organizations operating reserve credits: 2012

		Top 10 units		Top 10 organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$75,857,182	45.7%	$158,519,962	95.5%
Balancing	Canceled Resources	$2,572,219	75.7%	$3,270,179	96.2%
	Generators	$74,128,192	32.5%	$193,659,898	84.9%
	Local Constraints Control	$7,631,871	99.7%	$7,656,701	100.0%
	Lost Opportunity Cost	$55,649,002	29.1%	$165,253,202	86.4%
Reactive Services		$34,029,951	65.7%	$46,960,654	90.7%
Synchronous Condensing		$96,664	65.2%	$148,250	100.0%
Total		$146,866,389	22.7%	$529,565,259	81.7%

Table 3-31 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2012, 48.7 percent of all credits paid to these units were allocated to deviations while the remaining 51.3 percent were paid for reliability reasons.

Table 3-31 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2012

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$2,736,618	$6,677,489	$28,628,872	$32,428,073	$3,657,141	$0	$74,128,192
Share	3.7%	9.0%	38.6%	43.7%	4.9%	0.0%	100.0%

In 2012, concentration in all operating reserve credits categories was high.[17,18] Operating reserve credits HHI was calculated based on each organization's daily credits for each category. Table 3-32 shows the average HHI for each category. HHI for day-ahead operating reserve credits was 3720, for balancing operating reserve credits was 3105 and for lost opportunity cost credits was 4169.

17 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

18 Table 3-32 excludes the local constraints control categories.

Table 3-32 Daily operating reserve credits HHI: 2012

Category	Type	Average	Minimum	Maximum	Highest market share (One day)	Highest market share (All days)
Day-Ahead	Generators	3720	1229	10000	100.0%	33.0%
	Imports	10000	10000	10000	100.0%	60.3%
	Load Response	10000	10000	10000	100.0%	99.8%
Balancing	Canceled Resources	7101	1864	10000	100.0%	36.2%
	Generators	3105	1256	8396	91.5%	24.0%
	Imports	10000	10000	10000	100.0%	69.4%
	Load Response	9616	6957	10000	100.0%	38.4%
	Lost Opportunity Cost	4169	779	10000	100.0%	23.5%
Reactive Services		5985	1646	10000	100.0%	26.7%
Synchronous Condesing		10000	10000	10000	100.0%	100.0%
Total		1706	821	4820	68.2%	16.7%

Day-Ahead Unit Commitment for Reliability

The Day-Ahead Energy Market is solved with the objective function of minimizing the total production cost of meeting day-ahead load plus reserves subject to security constraints.[19] Under some circumstances PJM deviates from the optimal day-ahead solution when PJM is reasonably certain that specific units will be needed for reliability reasons in real time. Such actions by PJM may also be equivalent to appropriately reflecting known real time constraints in the day ahead market. PJM should be more transparent about these decisions and the reasons for them. In that case, PJM schedules the units as must run in the day ahead also. Participants can submit units as self-scheduled (must run), meaning that the unit must be committed.[20] A unit submitted as must run by a participant cannot set LMP and is not eligible for operating reserve credits. Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for operating reserve credits.

On September 13, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process of combustion turbines in real time. The increase in such scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Market. The MMU supports the concept of PJM's change in unit commitment as consistent with improved market efficiency because it appeared consistent with reflecting known real time constraints in the day ahead market. However, it would have been preferable to provide more notice to the market participants and to go through the stakeholder process to consider this change prior to implementation.

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 put such reliability issues in four categories:[21] voltage issues (high and low); black start requirement (from automatic load rejection units); local contingencies not seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.

The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. Day-ahead operating reserve charges are paid by day-ahead load, day-ahead exports and decrement bids across the entire RTO region. Balancing operating reserve charges are paid by real-time load and real-time exports or by deviations from the day ahead depending on the allocation process. Balancing operating reserve charges are allocated across three different regions, while day-ahead operating reserve charges are not. In addition, reactive services charges in real time (attributable to units providing voltage support) are paid by real-time load on a zonal level.

19 OATT Attachment K - Appendix § 1.10.8 (a)

20 See "PJM eMkt Users Guide" Section Managing Unit Data (version June, 2012) p. 40.

21 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.

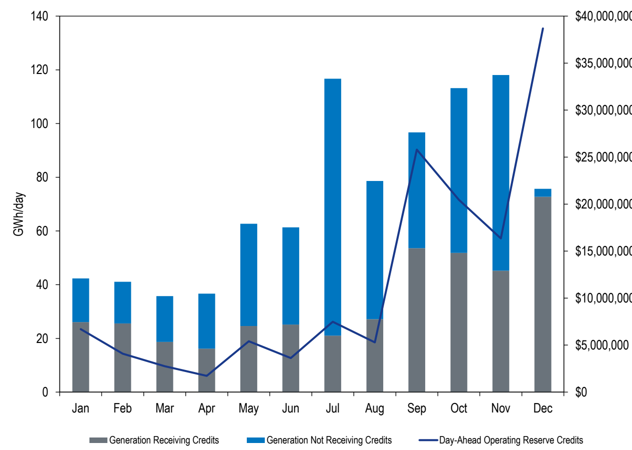
The effects of this decision on the operating reserve rates can be seen in Figure 3-1, Figure 3-2 and Figure 3-3. Figure 3-1 shows an increase in the day-ahead operating reserve rates after September 2012, and Figure 3-2 and Figure 3-3 show a decrease in the balancing operating reserve rates. Table 3-33 shows the average operating reserve rates from January 1 through September 12, 2012 and from September 13 through December 31, 2012. The average day-ahead operating reserve rate after September 13 increased by 324.3 percent compared to the average before September 13, while the average Western Region balancing operating reserve reliability rate decreased by 97.9 percent after September 13.[22]

Table 3-33 Average operating reserve rates before and after September 13, 2012

	Rate before September 13 ($/MWh)	Rate after September 13 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.104	0.443	0.338	324.3%
RTO Reliability	0.024	0.026	0.003	11.7%
East Reliability	0.029	0.003	(0.027)	(91.1%)
West Reliability	0.160	0.003	(0.156)	(97.9%)
RTO Deviations	0.964	0.428	(0.536)	(55.6%)
East Deviations	0.255	0.540	0.285	111.5%
West Deviations	0.137	0.101	(0.036)	(26.2%)
Lost Opportunity Cost	1.351	1.249	(0.102)	(7.5%)
Canceled Resources	0.032	0.002	(0.030)	(93.5%)

Figure 3-5 shows the total day-ahead generation of units scheduled as must run by PJM and the subset of generation from units scheduled as must run by PJM that received day-ahead operating reserve credits. Figure 3-5 also shows the day-ahead operating reserve credits paid to these units. November had the highest day-ahead generation from units scheduled as must run by PJM in 2012.[23] Before September 13, the average daily day-ahead generation from units scheduled as must run by PJM receiving day-ahead operating reserve credits was 23.6 GWh per day. After September 13, the daily average increased to 58.4 GWh per day. Before September 13, day-ahead operating reserve credits averaged $0.2 million per day and balancing operating reserve credits (including lost opportunity costs and canceled resources credits) averaged $1.3 million per day. After September 13 the day-ahead operating reserve credits averaged $0.9 million per day and the balancing operating reserve credits averaged $0.8 million per day. Although these results show a distinct pattern, the time periods are not strictly comparable since operating reserve credits are historically low during shoulder months.

Figure 3-5 Daily average day-ahead generation from units scheduled as must run by PJM: 2012

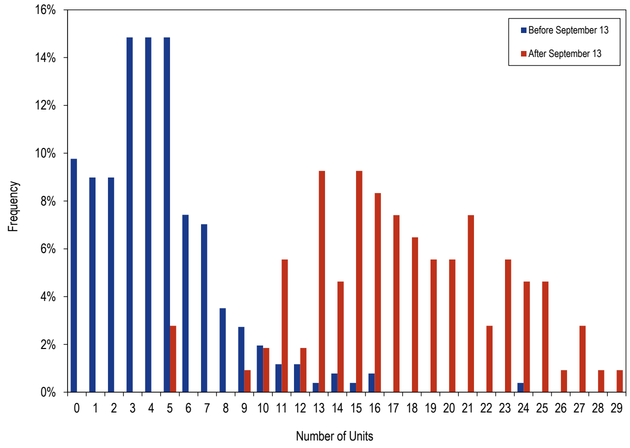


PJM scheduled an average of 9.4 units per day as must run before September 13 and on average 4.4 units received day-ahead operating reserve credits. After September 13, PJM scheduled as must run an average of 22.8 units per day and on average 17.9 units received day-ahead operating reserve credits. Figure 3-6 shows the frequency of the number of units scheduled as must run by PJM receiving day-ahead operating reserve credits before and after September 13 in 2012. For example, before September 13, three units scheduled as must run by PJM received day-ahead operating reserve credits on 14.8 percent of the days. After September 13, 13 units scheduled as must run by PJM received day-ahead operating reserve credits on 9.3 percent of the days.

22 This comparison is illustrative. The increase of the day-ahead operating reserve rate is not comparable to the decrease of the balancing operating reserve rates since the calculation of the rates have different denominators.

23 July had the second highest day-ahead generation from units scheduled as must run by PJM. PJM issued 12 hot weather alerts for the RTO region or the Mid-Atlantic region in July out of a total of 20 in 2012 for those regions.

Figure 3-6 Units scheduled as must run by PJM receiving day-ahead operating reserve credits: 2012



On October 10, 2012, PJM presented a problem statement at PJM's Market Implementation Committee (MIC) indicating the need to modify the allocation rules of day-ahead operating reserve charges as a result of the shift of balancing operating reserve charges to the Day-Ahead Energy Market.[24] Through PJM's stakeholder process two decisions were made to address the issue, both decisions were based on and consistent with the MMU recommendations:

- As a short term solution, PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes.[25] The proposed revisions allocated the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide black start service would be determined according to Schedule 6A of the OATT and the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide reactive service or transfer interface control would be allocated zonally in proportion to the real-time deliveries of energy to load.
- As a long term solution, a broader stakeholder process was initiated to consider market design and cost allocation issues in detail and propose OATT changes where needed.[26]

The MMU recommends PJM clearly identify and classify all reasons for incurring in operating reserves in the Day-Ahead and the Real-Time Energy Markets in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Lost Opportunity Cost Credits

In 2012, lost opportunity cost credits increased by $18.8 million or 10.9 percent compared to 2011.

Balancing operating reserve lost opportunity cost 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 dispatched 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 will have to pay.[27] If a unit generating in real time with an offer price lower than the LMP at the unit's bus is reduced or suspended by PJM, the unit will receive a credit for lost opportunity cost based on the desired output.

On April 3, 2012, PJM implemented a new rule to reduce the unnecessary payment of operating reserve credits to combustion turbines and diesels that are committed day ahead but not dispatched in real time. Under the new rule, such units are eligible for lost opportunity cost credits only if their lead times (notification plus start time) are less than or equal to two hours.[28]

Table 3-34 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. In 2012, PJM scheduled 20,254 GWh from combustion

24 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.

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

26 PJM created the MIC sub group Day - Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation methodology of the costs of day-ahead operating reserve for reliability. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}>.

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

28 See "PJM Manual 28: Operational Agreement Accounting," Revision 56 (Effective October 1, 2012), p. 22.

turbines and diesels, of which 64.1 percent was not requested by PJM in real time and of which 53.1 percent received lost opportunity cost credits. In 2011, PJM scheduled 9,331 GWh from combustion turbines and diesels.

Table 3-34 Day-ahead generation from combustion turbines and diesels (GWh): 2011 and 2012

	2011			2012		
	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	188	66	46	572	435	373
Feb	174	75	69	753	590	546
Mar	352	232	205	1,408	1,076	921
Apr	264	121	95	1,870	1,431	1,249
May	671	472	270	1,926	1,250	1,046
Jun	1,317	713	487	2,586	1,624	1,235
Jul	2,944	1,276	878	3,898	1,424	988
Aug	1,478	765	585	2,356	1,383	1,122
Sep	775	426	342	1,635	1,169	1,032
Oct	375	261	227	1,079	895	797
Nov	454	323	252	1,319	1,018	823
Dec	339	212	151	851	678	625
Total	9,331	4,942	3,607	20,254	12,973	10,757
Share	100.0%	53.0%	38.7%	100.0%	64.1%	53.1%

In 2012, the top three control zones receiving lost opportunity cost credits, AP, ComEd and Dominion combined for 64.4 percent of all lost opportunity cost credits, 60.3 percent of all the day-ahead generation from combustion turbines and diesels, 65.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.5 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

Combustion turbines and diesels receive lost opportunity cost credits on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for lost opportunity cost credits for hours 10, 11, 17 and 18. Table 3-35 shows the lost opportunity costs 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 3-35 shows that $138.0 million or 72.2 percent of all lost opportunity cost credits were paid to combustion turbines and diesels that did not run for any hour in real time.

Table 3-35 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012

	Lost Opportunity Cost Credits	
	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule
Jan	$4,857,442	$355,007
Feb	$4,382,996	$154,019
Mar	$9,661,923	$894,042
Apr	$10,846,998	$1,028,201
May	$12,925,885	$2,775,886
Jun	$12,550,655	$2,163,079
Jul	$13,911,706	$13,967,989
Aug	$22,219,006	$3,415,961
Sep	$17,783,763	$2,196,639
Oct	$11,185,166	$1,296,974
Nov	$12,704,380	$2,130,370
Dec	$4,979,204	$364,570
Total	$138,009,125	$30,742,736

PJM may not run units in real time if the real-time value of that energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 3-36 shows the total day-ahead generation from combustion turbines and diesels that were not called in real time by PJM and received lost opportunity cost credit. Table 3-36 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2012, 69.6 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remaining 30.4 percent was noneconomic.

Table 3-36 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value[29]

	Day-Ahead Generation Not Requested in Real Time		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	309	136	445
Feb	422	248	670
Mar	805	287	1,092
Apr	1,126	329	1,455
May	875	363	1,237
Jun	835	667	1,501
Jul	826	402	1,228
Aug	946	397	1,343
Sep	880	305	1,185
Oct	710	193	903
Nov	782	280	1,062
Dec	434	298	732
Total	8,950	3,904	12,853
Share	69.6%	30.4%	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 being called in real time when they are economic.

Lost Opportunity Cost and Perfect Dispatch

PJM's Perfect Dispatch application solves the security-constrained unit commitment and dispatch problem by minimizing the total bid production cost, assuming that the real system conditions were known in advance.[30] Perfect Dispatch is a look-back application, which uses the real system conditions to solve the unit dispatch and commitment problem and to compare its solution with the actual unit dispatch and commitment. Since real conditions will never be perfectly forecasted, the Perfect Dispatch solution cannot be achieved in real time. The Perfect Dispatch solution is used by PJM as a performance index to measure the real-time operation efficiency.

The objective of Perfect Dispatch is to identify the optimal resource dispatch and commitment that does not cause reliability issues. The Perfect Dispatch application may redispatch generators (increase or decrease their output) and/or commit and decommit generators. Steam units can usually be redispatched but not committed or decommitted because of their operational parameters. Combustion turbines and diesels can usually be committed or decommitted.

In real time, total cost includes two components: the bid production cost (based on the amount of MWh delivered times the resources' committed offers plus no load and startup costs) and the lost opportunity cost paid to units scheduled in the Day-Ahead Energy Market and not called in real time. Perfect Dispatch only takes into account the first component. Without taking into account the second component, the Perfect Dispatch solution might dispatch or commit a unit in real time that could reduce the bid production cost by displacing a unit scheduled in the Day-Ahead Market. But Perfect Dispatch ignores the increase in lost opportunity cost operating reserve charges that result. Perfect Dispatch should achieve the least cost solution taking into account both components. More importantly, PJM dispatch should aim to achieve the least cost solution by accounting for the impact of dispatch decisions on operating reserve charges.

The MMU recommends including the lost opportunity costs paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not called in real time in the calculation of PJM's Perfect Dispatch. Perfect Dispatch should include the lost opportunity costs paid to these units for a proper assessment of the total cost of the system, which include the costs of not calling in real time units that were scheduled in the Day-Ahead Energy Market.

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs calculations consistent throughout the PJM rules.[31] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the

29 The total generation in Table 3-36 is lower than the Day-Ahead Generation not requested in Real Time in Table 3-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 3-36 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

30 See Gisin, B., Gu, Q. Mitsche, J., Tam, S. and Chen, H. "Perfect Dispatch as the Measure of PJM Real Time Grid Operational Performance" for a complete description of Perfect Dispatch <www.power-gem.com/Perfect_Dispatch_Paper_final.pdf>

31 See "Meeting Minutes" from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (April 4, 2012)

MMU has not formally recommended these to the MIC for consideration although they were brought to the attention of the MIC.

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the lost opportunity cost in the energy market. The MMU recommends that the lost opportunity cost in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market.
- **No load and startup costs:** Current rules do not include in the calculation of lost opportunity cost credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not dispatched 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 called in real time.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the lost opportunity cost calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the Day-Ahead Energy Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives lost opportunity cost credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits if necessary. If the unit is not dispatched in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost. The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **Offer Curve:** Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the lost opportunity cost in the PJM Energy Markets for units scheduled in day ahead but which are backed down or not dispatched 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 lost opportunity cost 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 lost opportunity cost 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 lost opportunity cost.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' price schedule if available and the unit does not fail the TPS test.

Table 3-37 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for 2012, for the two categories of lost opportunity cost credits. Energy lost opportunity cost credits would have been reduced by $60.8 million, or 31.8 percent, if all these changes had been implemented.[32]

32 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 3-37 Impact on energy market lost opportunity cost credits of rule changes: 2012

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$22,461,071	$168,751,861	$191,212,932
Impact 1: Committed Schedule	$1,346,013	$33,151,094	$34,497,107
Impact 2: Eliminating DA LMP	NA	($942,269)	($942,269)
Impact 3: Using Offer Curve	($1,200,074)	$13,712,971	$12,512,897
Impact 4: Including No Load Cost	NA	($82,053,680)	($82,053,680)
Impact 5: Including Startup Cost	NA	($24,853,844)	($24,853,844)
Net Impact	$145,939	($60,985,727)	($60,839,788)
Credits After Changes	$22,607,010	$107,766,133	$130,373,144

Table 3-38 shows the impact of each of the proposed modifications made jointly by PJM and the MMU. Energy lost opportunity cost credits would have been reduced by $67.0 million, or 35.0 percent, if the two proposed modifications had been implemented.

Table 3-38 Impact on energy market lost opportunity cost credits of proposed rule changes: 2012

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$22,461,071	$168,751,861	$191,212,932
Impact 1: Committed Schedule	$1,346,013	$33,151,094	$34,497,107
Impact 2: Including No Load Cost	NA	($78,359,367)	($78,359,367)
Impact 3: Including Startup Cost	NA	($23,119,630)	($23,119,630)
Net Impact	$1,346,013	($68,327,903)	($66,981,889)
Credits After Changes	$23,807,085	$100,423,958	$124,231,043

On November 7, 2012, PJM presented proposals addressing the consistency of lost opportunity cost calculations at PJM's Market Implementation Committee (MIC). Table 3-39 summarizes the two proposals that were voted on at the MIC. The MIC favored package 3 and both proposals were forwarded to the Markets and Reliability Committee (MRC).[33] The MRC approved indefinitely postponing voting on addressing the consistency of lost opportunity cost calculations.[34]

Table 3-39 Lost opportunity cost proposals

Market / Service	Category / Type	Status Quo	Package 2	Package 3
Energy	Combustion Turbines / Engines Scheduled DA not called RT	Higher of price-based and cost-based schedule	Committed schedule	Higher of price-based and cost-based schedule
	Units reduced in RT	Higher of price-based and cost-based schedule	Committed schedule	Operating cost-based schedule
Reactive Services	Units reduced in RT	Higher of price-based and cost-based schedule	Committed schedule	Operating cost-based schedule
Ancillary Services	Regulation	Lower of price-based scheduled and the higher cost-based schedule	Committed schedule	Committed schedule when raised cost-based schedule when lowered
	Day-Ahead Scheduling Reserves	Committed schedule	Committed schedule	Committed schedule when raised cost-based schedule when lowered
	Synchonized Reserves (Tier 2)	Committed schedule	Committed schedule	Committed schedule when raised cost-based schedule when lowered
	Non Synchronized Reserves	Committed schedule	Committed schedule	Committed schedule

33 See "Minutes" from PJM's MIC November 7, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx> (Accessed January 11, 2013).

34 See "Draft Minutes," from PJM's MRC December 20, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130131/20130131-draft-minutes-mrc-20121220.ashx> (Accessed January 24, 2013).

Lost Opportunity Cost for Wind Units

Lost opportunity cost credits are paid to wind units when reduced or suspended by PJM and the real-time LMP at the units' bus is greater than the units' offer. Wind units are paid the difference between their desired and actual output, multiplied by the difference between the real-time LMP and their offer. Under the current rules, the expected output of a wind unit is based on the lesser of the desired output and the forecasted output of the unit.[35]

The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs).[36]

The MMU recommends using the estimated output of the units based on actual wind conditions at the unit, not forecasted, to calculate wind units lost opportunity costs. Lost opportunity cost credits are calculated after the operating day, therefore there is no need to use forecasted wind conditions to calculate the output wind units could have achieved.

The MMU recommends using the capacity interconnection rights (CIRs) to calculate wind units' lost opportunity cost credits. In addition, the MMU recommends that PJM allow wind units, at their discretion, to submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. CIRs are the right, in MW, capacity resources have to input power into the transmission system.[37,38]

CIRs are linked to the capacity value resources may offer in the Capacity Market. For wind units, the capacity value is limited to the amount of capacity it can reliably contribute during summer peak hours.[39] CIRs of wind units are limited to their capacity capability in the summer peak hours and not their maximum output at any time.

PJM should make a distinction between the capacity value units can inject into the transmission system (CIRs) and the capacity value that units may offer in the Capacity Market. Wind units should be compensated for LOC taking into account the capacity value used to analyze the feasibility of interconnecting the resource to the transmission system. Network resources pay the costs of interconnecting to the system in order to receive interconnection service from PJM, including any upgrades if necessary. Resources that have not paid for transmission upgrades or only paid for upgrades based on a fraction of their maximum desired output have no right to inject additional energy when it causes reliability issues.

Wind units that elect to be capacity resources must have CIRs equal to 13 percent of their maximum output, or equal to their demonstrated capacity factor during summer peak hours. PJM should allow wind units to submit CIRs reflective of their maximum desired output and perform interconnection studies based on those values. Wind units would have to pay for any transmission upgrades needed to reliably inject that additional energy.

Table 3-40 shows the impact that the MMU proposal would have had on the lost opportunity cost credits paid to wind units in the energy market in 2012. Lost opportunity cost credits paid to wind units would have been reduced by $3.1 million, or 65.6 percent, if the change had been implemented. Lost opportunity costs paid to wind units are paid by deviations in the RTO region.

Table 3-40 Impact of proposed rule change on lost opportunity cost credits paid to wind units: 2012

	Current Wind LOC Credits	Wind LOC Credits with Proposed Change	Proposed Change Impact
Jan	$0	$0	$0
Feb	$0	$0	$0
Mar	$72	$72	$0
Apr	$0	$0	$0
May	$0	$0	$0
Jun	$119,146	$30,756	($88,390)
Jul	$63,805	$40,480	($23,326)
Aug	$175,321	$73,779	($101,542)
Sep	$834,466	$360,693	($473,774)
Oct	$2,799,801	$868,636	($1,931,164)
Nov	$215,730	$101,808	($113,922)
Dec	$441,436	$121,940	($319,495)
Total	$4,649,777	$1,598,165	($3,051,613)

35 The current lost opportunity cost credits to wind units became effective on June 1, 2012.

36 This issue was raised by the MMU in the PJM Lost Opportunity Cost for Wind filing. See PJM Interconnection, L.L.C. filing in FERC Docket No. ER12-1422-000 (April 23, 2012). "Comments of the Independent Market Monitor for PJM".

37 OATT 1 Definitions § 1.3C.

38 OATT IV Interconnections with the Transmission System § 36.1A.2.

39 "Manual 21: Rules and Procedures for Determination of Generating Capability" Revision 09 (May 1, 2010).

Lost Opportunity Cost Billing Error Resolution

On November 22, 2011, PJM filed a petition with FERC requesting a procedural framework within which to correct settlements of balancing operating reserve lost opportunity cost billings between 2009 and 2011.[40] The tariff provides for the calculation of lost opportunity cost as real-time LMP less the higher of the price or cost offer.[41] However, the software code included in the Market Settlement Calculation System (MSCS) calculated lost opportunity cost as real-time LMP less the price offer.[42] As a result, certain participants who regularly included cost offers higher than price offers and received operating reserve credits, received significant overpayments during the relevant period. PJM identified the need to correct its billings as provided in the tariff for an initial amount of approximately $96.6 million.[43]

PJM and the MMU engaged in discussions with Dominion Resources Services, Inc. (Dominion) and Ingenco Wholesale Power, L.L.C. (Ingenco), the participants who received most of the overpayments, to calculate a billing adjustment that represented both companies' generating units' real costs.[44] Both participants submitted data regarding their fuel supply arrangements, fuel costs, operating characteristics of the relevant units and other factors that impact their final production cost. On August 16, 2012, PJM submitted an Offer of Settlement and Stipulation (Stipulation) specifying the terms and conditions agreed to by all parties and the final refunds from Dominion and Ingenco.[45]

Black Start and Voltage Support Units

Certain units located in the Western Region are relied on for their black start capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the Automatic Load Rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The MMU recommended that PJM dispatchers explicitly log the reasons that these units are run out-of-merit whether to comply with black start requirements or to provide voltage support in order to correctly assign the associated charges.

On August 8, 2012, the PJM Market Implementation Committee (MIC) endorsed a charge presented by the MMU to prepare a proposal to correct the allocation of make whole payments (in the form of operating reserve charges) attributable to the operation of units for black start requirement and black start testing.[46]

PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the short term allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes. The proposal also included a solution to correct the allocation of the cost of all operating reserves paid to units providing black start or performing black start testing.[47] The proposed revision allocated the costs of day-ahead operating reserves and balancing operating reserve of such units scheduled in the Day-Ahead Energy Market and/or committed in real time according to Schedule 6A of the OATT. This solution was consistent with the MMU's recommendation. FERC accepted the proposed revisions with December 1, 2012 as the effective date.

Con Edison – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG.[48] These units are often run out-of-merit and received substantial balancing operating reserve credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

40 See Petition of PJM Interconnection, L.L.C. for Institution of Proceeding to Determine Proper Billing Adjustments and for Waiver of Tariff, Docket No. ER12-469-000 (December 22, 2011) (December 22nd Petition).
41 OATT Attachment K - Appendix § 3.2.3 (f) & (f-1).
42 December 22nd Petition at 2–3.
43 *Id.* at 4; OA Schedule 1 § 15.6.
44 *Id.* at 8–9.
45 See Offer of Settlement and Stipulation of PJM Interconnection, L.L.C., Docket No. ER12-469 (August 16, 2012).
46 See "Minutes," from PJM's MIC August 8, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120808/20120808-minutes.ashx> (Accessed January 11, 2013).
47 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).
48 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[49] Under the rules providing for credits for reactive service, 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 service credits do not cover a unit's entire offer, the unit is paid through balancing operating reserves. The result is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

In 2012, units providing reactive services were paid $21.9 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 92.1 percent were paid by deviations in the RTO Region, 6.4 percent by real-time load and real-time exports in the RTO Region, 1.2 percent by deviations in the Eastern and Western Regions and the remaining 0.3 percent by real-time load and real-time exports in the Western Region.

Table 3-41 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-41 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): 2012

		Balancing Operating Reserve Rates ($/MWh)		Difference	
Category	Region	Current	Without Credits to Units Providing Reactive Services	($/MWh)	Percentage
Reliability	RTO	0.024	0.023	(0.002)	(7.2%)
	East	0.022	0.022	0.000	0.0%
	West	0.115	0.115	(0.000)	(0.1%)
Deviation	RTO	0.815	0.675	(0.139)	(17.1%)
	East	0.333	0.332	(0.001)	(0.4%)
	West	0.126	0.124	(0.003)	(2.1%)

On October 10, 2012 and November 7, 2012 the MMU presented this issue at PJM's Market Implementation Committee (MIC).[50,51] The MIC endorsed the issue charge and approved merging this issue with the long term solution of the allocation of the cost of day-ahead operating reserves for reliability.[52]

The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be equal to the positive difference between total offer (including no load and startup costs) and energy revenues. In addition, the MMU recommends that reactive services credits be calculated on segments which include all hours for which unit provides reactive service. Segments should be the higher of hours needed for reactive support and minimum run time.

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on operating reserve rates if up-to congestion transactions had paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do, while accounting for the impact of such payments on the profitability of the transactions.

In 2012, 54.5 percent of all up-to congestion transactions were profitable.[53]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied. It was assumed that up-to congestion transactions would have had the same shares of profitable and unprofitable transactions after paying operating reserve charges as occurred when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, only 34.3 percent of all up-to congestion transactions would have been made. Even with this reduction in the

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

50 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," from the PJM's MIC October 10, 2012 meeting. <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>. (Accessed January 11, 2013)

51 See "Minutes," from PJM's MIC November 7, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx> (Accessed January 11, 2013).

52 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}> (Accessed January 11, 2013).

53 An up-to congestion transaction profitability is based on its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.

level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

Table 3-42 shows the impact that including the identified 34.3 percent of up-to congestion transactions in the allocation of operating reserve charges would have had on the operating reserve charge rates in 2012. For example, the RTO deviations rate would have been reduced by 59.3 percent.

Table 3-42 Up-to congestion transactions impact on operating reserve rates: 2012

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.200	0.177	(0.023)	(11.3%)
RTO Deviations	0.815	0.332	(0.483)	(59.3%)
East Deviations	0.333	0.191	(0.142)	(42.7%)
West Deviations	0.126	0.038	(0.088)	(69.9%)
Lost Opportunity Cost	1.322	0.538	(0.784)	(59.3%)
Canceled Resources	0.024	0.010	(0.014)	(59.3%)

The MMU recommends, while the up-to congestion transaction product remains and without a plan to examine the allocation of all operating reserve charges, PJM should require all up-to congestion transactions to pay day-ahead and balancing operating reserve charges.