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.[1] 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.

Highlights

- Operating reserve charges decreased $27.0 million, or 10.1 percent, from $267.4 million in the first six months of 2011, to $240.4 million in the first six months of 2012. Day-ahead operating reserve charges decreased $12.0 million, or 25.0 percent to $35.9 million and balancing operating reserve charges decreased $14.7 million, or 6.7 percent to $204.5 million.
- Balancing operating reserve charges for reliability increased by $1.8 million, or 4.0 percent compared to the first six months of 2011. Balancing reserve charges for deviations decreased by $17.0 million, or 17.2 percent.
- The reduction in balancing operating reserve charges was comprised of a decrease of $15.2 million in generator and real-time import transactions balancing operating reserve charges, a decrease of $1.3 million in lost opportunity costs, a decrease of $1.9 million in canceled resources and an increase of $3.6 million in charges to participants requesting resources to control local constraints.
- Generators and real-time transactions balancing operating reserve charges were $128.2 million, 62.7 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 36.5 percent as reliability charges and 63.5 percent as deviation charges. Lost opportunity cost charges were $67.6 million or 33.0 percent of all balancing charges. The remaining 4.3 percent of balancing operating reserve charges were comprised of 1.6 percent canceled resources charges and 2.7 percent of local constraints control charges.
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 26.0 percent of total operating reserve credits in the first six months of 2012, compared to 34.3 percent in the first six months of 2011.
- The regional concentration of operating reserves remained high in the first six months of 2012. In the first six months of 2012, 51.5 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 15.5 percentage points from the first six months of 2011.

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.

1 See the *2011 State of the Market Report for PJM: Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" for a full description of how operating reserve credits and charges are calculated.

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, startup and no-load offers.

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, PJM should take another step towards more precise definition of the reasons for incurring operating reserve charges and about the necessity of paying operating reserve charges in some cases. 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.

In addition, the allocation of operating reserve charges to participants should 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 goal should 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 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.

Operating Reserve Credits and Charges

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.

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 shows the categories of credits and charges and their relationship. This table shows how charges are allocated. Table 3-2 shows the different types of deviations.

Table 3-1 Operating reserve credits and charges (See 2011 SOM, Table 3-1)

	Credits received for:		Charges paid by:
		Day-Ahead	
	Day-Ahead Import Transactions Demand-Side Response Resources Generation Resources	→	Day-Ahead Demand Bid Day-Ahead Export Transactions Decrement Bids
	Synchronous Condensing	→	Real-Time Export Transactions Real-Time Load
		Balancing	
Generation Resources	Deviations	→	Real-Time Deviations from Day-Ahead Schedule by RTO, East and West Region
Generation Resources	Reliability	→	Real-Time Load plus Export Transactions by RTO, East and West Region
	Canceled Resources Demand-Side Response Resources Lost Opportunity Cost Performing Annual Scheduled Black Start Tests Providing Quick Start Reserve Real-Time Import Transactions	→	Real-Time Deviations from Day-Ahead Schedule in the entire RTO
	Local Constraints Control	→	Applicable Requesting Party
	Providing Reactive Service	→	Zonal Real-Time Load

Table 3-2 Operating reserve deviations (See 2011 SOM, Table 3-2)

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

Operating Reserve Results

Operating Reserve Charges

Table 3-3 shows total operating reserve charges for the first six months of 2011 and 2012.[2] Total operating reserve charges decreased by 10.1 percent in the first six months of 2012 compared to the first six months of 2011, to a total of $240.4 million.

Table 3-3 Total operating reserve charges: January through June 2011 and 2012 (See 2011 SOM, Table 3-6)[3]

	Jan-Jun 2011	Jan-Jun 2012	Change	Percentage Change
Total Operating Reserve Charges	$267,429,333	$240,434,136	($26,995,197)	(10.1%)
Operating Reserve as a Percent of Total PJM Billing	1.4%	1.7%	0.3%	20.1%
Day-Ahead Rate ($/MWh)	0.124	0.089	(0.035)	(28.2%)
Balancing RTO Deviation Rate ($/MWh)	1.079	0.944	(0.135)	(12.5%)
Balancing RTO Reliability Rate ($/MWh)	0.086	0.020	(0.066)	(77.1%)

Total operating reserve charges in the first six months of 2012 were $240.4 million, down from the total of $267.4 million in the first six months of 2011. Table 3-4 compares monthly operating reserve charges by category for calendar years 2011 and 2012. The decrease of 10.1 percent in the first six months of 2012 is comprised of a 25.0 percent decrease in day-ahead operating reserve charges, a 90.6 percent decrease in synchronous condensing charges and a 6.7 percent decrease in balancing operating reserve charges.

The reduction in day-ahead operating reserve credits was primarily a result of a lower spread between the total energy offer of units receiving day-ahead operating reserve credits and the LMP at the units' buses.

2 Table 3-3 includes all categories of charges as defined in Table 3-1 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 July 9, 2012.

3 The total operating reserve charges in Table 3-3 are $7.8 million lower than the total charges published in the *2011 State of the Market Report for PJM*. PJM may recalculate new settlements after the State of the Market report is published.

Table 3-4 Monthly operating reserve charges: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-7)

	2011				2012			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$12,373,099	$110,095	$47,090,369	$59,573,563	$8,311,574	$15,362	$27,322,330	$35,649,266
Feb	$8,940,203	$139,287	$26,607,792	$35,687,282	$5,858,308	$18,592	$24,869,649	$30,746,549
Mar	$6,837,719	$66,032	$23,238,170	$30,141,921	$3,852,873	$1,648	$29,707,310	$33,561,831
Apr	$4,405,102	$13,011	$18,764,254	$23,182,366	$2,967,302	$0	$33,358,697	$36,325,999
May	$7,064,934	$39,417	$43,540,784	$50,645,135	$7,956,965	$0	$43,375,034	$51,331,998
Jun	$8,303,391	$9,056	$59,886,618	$68,199,066	$6,988,065	$0	$45,830,427	$52,818,492
Jul	$4,993,311	$238,127	$106,596,647	$111,828,085				
Aug	$8,360,392	$104,982	$55,142,158	$63,607,531				
Sep	$6,249,240	$40,878	$36,617,421	$42,907,539				
Oct	$5,133,837	$0	$20,415,483	$25,549,319				
Nov	$7,063,847	$0	$19,528,707	$26,592,554				
Dec	$7,593,046	$0	$24,716,729	$32,309,775				
Total	$47,924,448	$376,898	$219,127,987	$267,429,333	$35,935,087	$35,603	$204,463,446	$240,434,136
Share of Charges	17.9%	0.1%	81.9%	100.0%	14.9%	0.0%	85.0%	100.0%

Table 3-5 shows the monthly composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing generation, real-time import transaction, lost opportunity cost charges, canceled pool-scheduled resources, and charges paid to resources controlling local constraints. In the first six months of 2012, generation and transactions charges decreased by $15.2 million or 10.6 percent, lost opportunity cost charges decreased by $1.3 million or 1.8 percent, canceled resources charges decreased by $1.9 million or 36.4 percent and charges for local constraints control increased by $3.6 million or 205.0 percent.

Table 3-5 Monthly balancing operating reserve charges by category: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-8)

	2011				2012			
	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control
Jan	$43,170,696	$2,946,513	$639,107	$334,052	$20,440,833	$5,449,229	$777,386	$654,882
Feb	$22,698,872	$3,205,948	$208,046	$494,927	$18,907,159	$4,644,133	$517,613	$800,744
Mar	$15,456,921	$7,094,881	$358,223	$328,146	$16,987,307	$10,777,661	$1,120,962	$821,380
Apr	$11,096,912	$7,222,704	$303,514	$141,123	$19,459,487	$12,490,267	$409,047	$999,896
May	$20,331,609	$20,364,971	$2,742,644	$101,559	$23,046,426	$19,094,193	$450,135	$784,279
Jun	$30,610,434	$27,996,648	$901,825	$377,711	$29,353,488	$15,116,271	$0	$1,360,668
Jul	$56,565,647	$46,241,739	$299,606	$3,489,655				
Aug	$29,078,083	$24,142,105	$302,975	$1,618,995				
Sep	$17,735,689	$16,948,063	$151,195	$1,782,474				
Oct	$10,460,806	$6,327,845	$1,250,928	$2,375,903				
Nov	$11,415,410	$6,181,160	$1,663,154	$268,983				
Dec	$20,477,899	$3,574,430	$306,260	$358,140				
Total	$143,365,444	$68,831,664	$5,153,360	$1,777,519	$128,194,701	$67,571,754	$3,275,143	$5,421,848
Share of Charges	65.4%	31.4%	2.4%	0.8%	62.7%	33.0%	1.6%	2.7%

Table 3-6 and Table 3-7 show the amount and percentages of regional balancing charge allocations for the first six months of 2011 and 2012. The largest share of charges was paid by RTO demand deviations. 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 the first six months of 2012, balancing operating reserve charges, excluding lost opportunity costs, canceled resources and local constraints control categories, decreased by $15.2 million compared to the first six months of 2011. Balancing operating reserve charges for reliability increased by $1.8 million or 4.0 percent and balancing reserve charges for deviations decreased by $17.0 million or 17.2 percent. Reliability charges in the Western Region increased by $27.0 million compared to the first six months of 2011, as a result of payments to units providing black start and voltage support. The remaining two reliability categories decreased by $25.2 million. The decrease in balancing operating reserve charges was mainly a result of a lower spread between the units' energy offer and the real-time LMP. The total real-time generation receiving balancing operating reserve credits increased by 12.7 percent.

Table 3-6 Regional balancing charges allocation: January through June 2011[4] (See 2011 SOM, Table 3-9)

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$29,498,613	13.6%	$2,990,681	1.4%	$10,710,142	4.9%	$43,199,436	19.9%
	Real-Time Exports	$1,160,201	0.5%	$93,186	0.0%	$555,740	0.3%	$1,809,127	0.8%
	Total	$30,658,814	14.1%	$3,083,867	1.4%	$11,265,882	5.2%	$45,008,563	20.7%
Deviation Charges	Demand	$52,505,729	24.2%	$5,651,227	2.6%	$1,447,136	0.7%	$59,604,092	27.4%
	Supply	$16,694,849	7.7%	$1,464,811	0.7%	$614,565	0.3%	$18,774,225	8.6%
	Generator	$17,899,448	8.2%	$1,464,218	0.7%	$614,897	0.3%	$19,978,564	9.2%
	Total	$87,100,027	40.1%	$8,580,256	3.9%	$2,676,598	1.2%	$98,356,881	45.3%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$45,535,553	21.0%	$0	0.0%	$0	0.0%	$45,535,553	21.0%
	Supply	$13,001,659	6.0%	$0	0.0%	$0	0.0%	$13,001,659	6.0%
	Generator	$15,447,812	7.1%	$0	0.0%	$0	0.0%	$15,447,812	7.1%
	Total	$73,985,024	34.0%	$0	0.0%	$0	0.0%	$73,985,024	34.0%
Total Balancing Charges		$191,743,865	88.2%	$11,664,123	5.4%	$13,942,480	6.4%	$217,350,468	100%

4 The total charges shown in Table 3-6 do not equal the total balancing charges shown in Table 3-5 because the totals in Table 3-5 include charges to resources controlling local constraints while the totals in Table 3-6 do not.

Table 3-7 Regional balancing charges allocation: January through June 2012[5] (See 2011 SOM, Table 3-9)

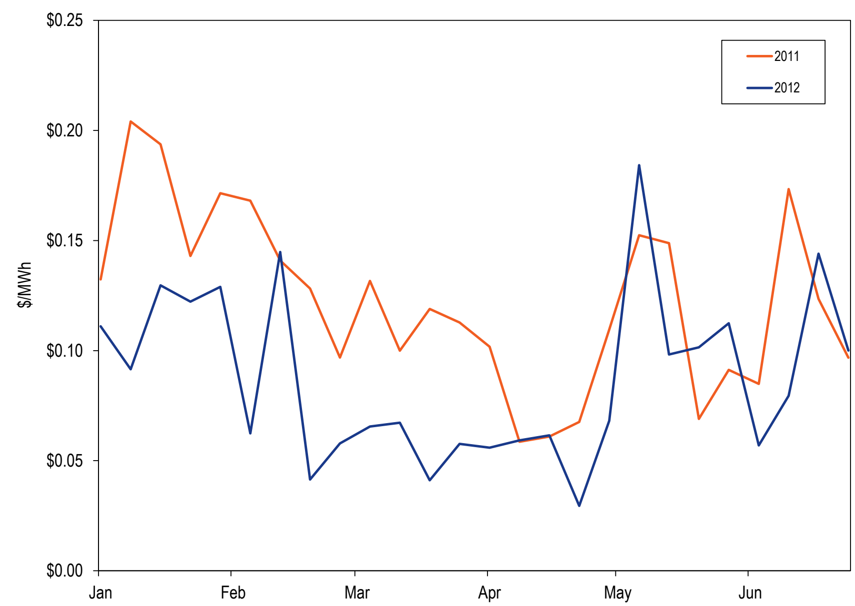
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$7,330,726	3.7%	$1,002,489	0.5%	$36,755,608	18.5%	$45,088,822	22.7%
	Real-Time Exports	$203,103	0.1%	$17,392	0.0%	$1,492,365	0.7%	$1,712,860	0.9%
	Total	$7,533,828	3.8%	$1,019,881	0.5%	$38,247,973	19.2%	$46,801,682	23.5%
Deviation Charges	Demand	$40,718,038	20.5%	$6,118,822	3.1%	$1,672,092	0.8%	$48,508,952	24.4%
	Supply	$12,959,577	6.5%	$2,226,118	1.1%	$467,215	0.2%	$15,652,910	7.9%
	Generator	$14,748,692	7.4%	$1,665,019	0.8%	$817,446	0.4%	$17,231,157	8.7%
	Total	$68,426,307	34.4%	$10,009,960	5.0%	$2,956,753	1.5%	$81,393,019	40.9%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$40,587,324	20.4%	$0	0.0%	$0	0.0%	$40,587,324	20.4%
	Supply	$14,255,358	7.2%	$0	0.0%	$0	0.0%	$14,255,358	7.2%
	Generator	$16,004,215	8.0%	$0	0.0%	$0	0.0%	$16,004,215	8.0%
	Total	$70,846,897	35.6%	$0	0.0%	$0	0.0%	$70,846,897	35.6%
Total Balancing Charges		$146,807,032	73.8%	$11,029,840	5.5%	$41,204,725	20.7%	$199,041,598	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. See Table 3-1 for how these charges are allocated.

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for the first six months of 2011 and 2012. The average rate in the first six months of 2012 was $0.0892 per MWh, $0.0351 per MWh lower than the average of the first six months of 2011. The highest rate occurred on June 20, when the rate reached $0.3658 per MWh, 1.5 percent higher than the $0.3603 reached during the first six months of 2011, on January 14. The highest rate in 2012 was a result of conservative operation scheduling by PJM for the hot weather related demand that affected the Mid-Atlantic Region beginning on June 20.

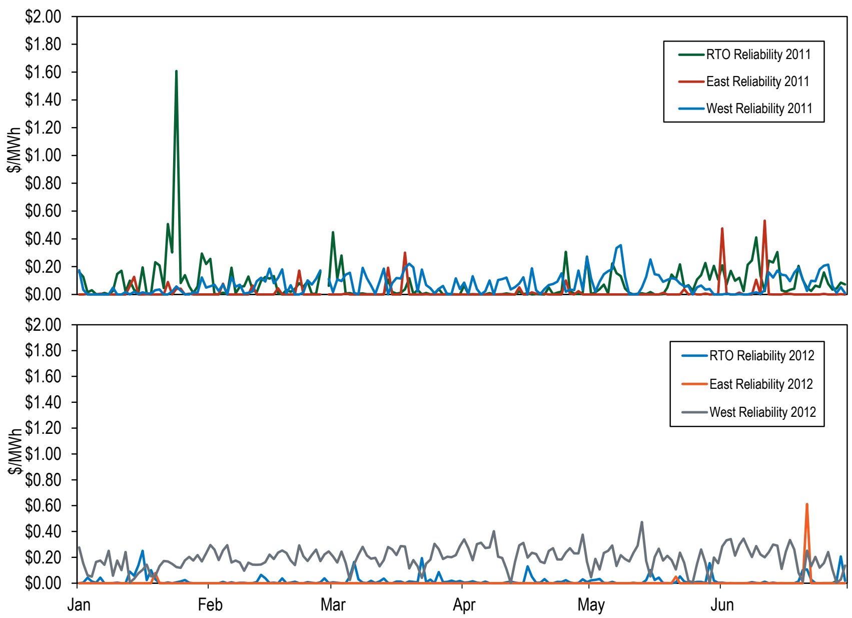
Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): January through June 2011 and 2012 (See 2011 SOM, Figure 3-1)



5 The total charges shown in Table 3-7 do not equal the total balancing charges shown in Table 3-5 because the totals in Table 3-5 include charges to resources controlling local constraints while the totals in Table 3-7 do not.

Figure 3-2 shows the RTO and the regional reliability rates for the first six months of 2011 and 2012. The average daily RTO reliability rate was $0.0197 per MWh. The highest RTO reliability rate of 2012 occurred on January 16, when the rate reached $0.2506 per MWh. In the first six months of 2012, reliability rates in the Eastern Region were positive for only three days. On June 21 conservative operations to address hot weather related demand in the Mid-Atlantic Region from June 20 through June 22 resulted in the use of local units out of merit, which resulted in an increase in the Eastern Region reliability rate of $0.6121. Reliability rates in the Western Region have been high primarily because of the use of certain units to provide black start and voltage support.[6]

Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): January through June 2011 and 2012 (See 2011 SOM, Figure 3-2)



6 PJM issued consecutive Hot Weather Alerts for the entire RTO region for June 20 and June 21 and for the Dominion and Mid-Atlantic Zones for June 22.

Figure 3-3 shows the RTO and the regional deviation rates for the first six months of 2011 and 2012. The average daily RTO deviation rate was $0.9443 per MWh. The highest daily rate occurred on June 29, when the RTO deviation rate reached $3.9347 per MWh. The highest Eastern Region rate occurred on March 5, when two units in the BGE and Dominion Control Zones were committed out of merit to provide relief to the 230 kV transmission network after the loss of a 500 kV line. 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): January through June 2011 and 2012 (See 2011 SOM, Figure 3-2)

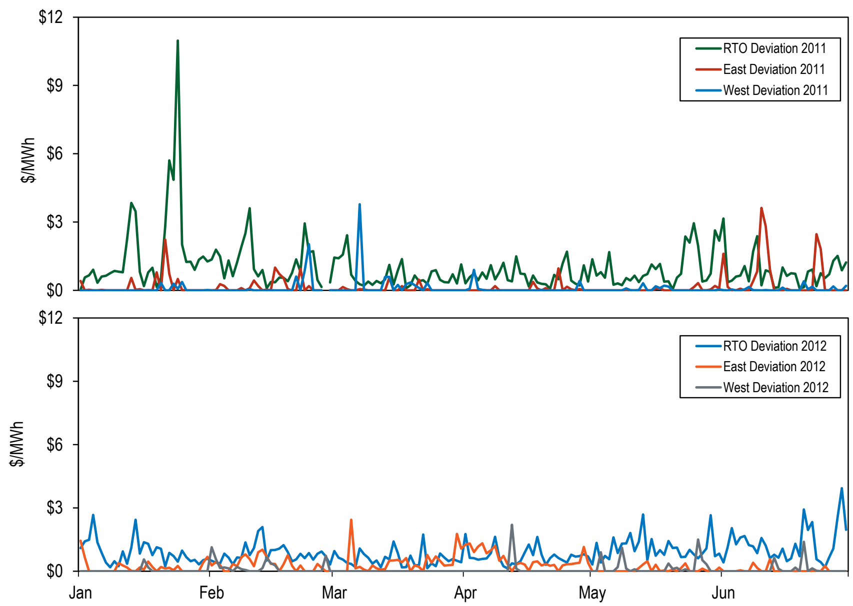


Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for the first six months of 2011 and 2012. The lost opportunity rate averaged $0.9325 per MWh. The highest lost opportunity cost rate occurred on May 29, when it reached $6.5281 per MWh. Increases in the lost 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 $0.0452 per MWh and credits were paid during 41.5 percent of all the days in the first six months of 2012.

Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): January through June 2011 and 2012 (See 2011 SOM, Figure 3-2)

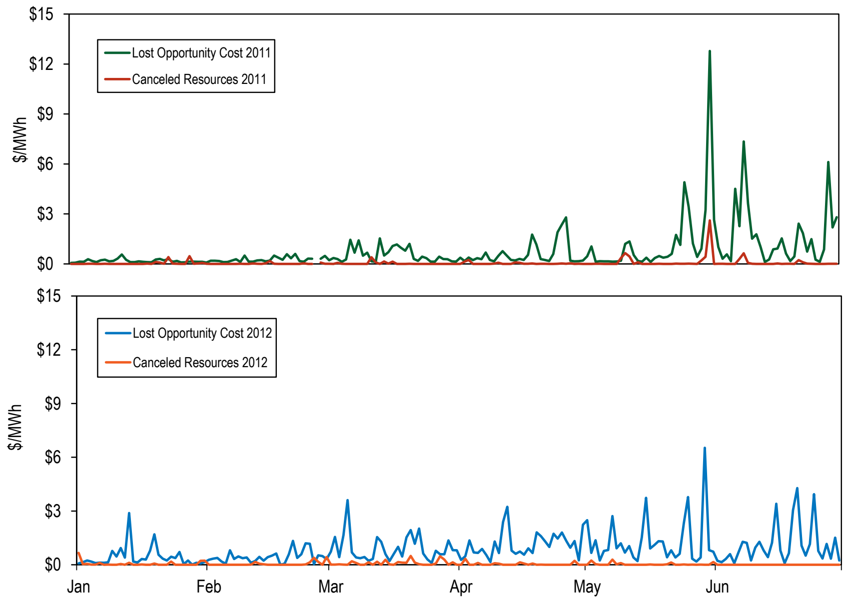


Table 3-8 shows the rates for each region in each category. RTO deviation charges and lost opportunity cost charges accounted for 66.5 percent of all balancing operating reserve charges in the first six months of 2012.

Table 3-8 Balancing operating reserve rates ($/MWh): January through June 2011 and 2012 (See 2011 SOM, Table 3-10)

	2011				2012			
	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.020	0.944	0.932	0.045	0.086	1.079	0.853	0.064
East	0.006	0.251	NA	NA	0.016	0.187	NA	NA
West	0.187	0.091	NA	NA	0.067	0.077	NA	NA

Table 3-9 shows the operating reserve cost of a 1 MW transaction during the first six months of 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.1894 per MWh with a maximum rate of $9.3010 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $1.1452 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges. Table 3-9 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 3-9 Operating reserve rates statistics ($/MWh): January through June 2012 (See 2011 SOM, Table 3-11)

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	9.183	2.101	0.330	1.147
	DEC	9.301	2.189	0.470	1.145
	DA Load	0.366	0.088	0.000	0.058
	RT Load	0.719	0.022	0.000	0.065
	Deviation	9.183	2.101	0.330	1.147
West	INC	9.183	1.923	0.330	1.198
	DEC	9.301	2.012	0.409	1.203
	DA Load	0.366	0.088	0.000	0.058
	RT Load	0.473	0.211	0.010	0.077
	Deviation	9.183	1.923	0.330	1.198

Deviations

Under PJM's operating reserve rules, credits allocated to generators defined to be operating to control deviations on the system, lost opportunity credits and credits to canceled resources are charged to deviations. 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.

Table 3-10 shows monthly real-time deviations for demand, supply and generator categories for 2011 and the first six months of 2012. These deviations are the sum of the regional deviations. Total deviations summed across the demand, supply, and generator categories were lower in the first six months of 2012 compared to the first six months of 2011 by 8,239,643 MWh or 10.2 percent. Demand deviations decreased by 13.3 percent, supply deviations decreased by 6.3 percent, and generator deviations decreased by 5.0 percent. In the first six months of 2012 compared to the first six months of 2011, the share of total deviations in the demand category decreased by 2.1 percentage points, the share of supply deviations increased by 0.8 percentage points, and the share of generator deviations increased by 1.2 percentage points.

Table 3-10 Monthly balancing operating reserve deviations (MWh): Calendar years 2011 and 2012 (See 2011 SOM, Table 3-3)

	2011 Deviations				2012 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,798,230	3,261,409	3,107,683	16,167,323	7,340,668	2,496,321	2,779,139	12,616,128
Feb	7,196,554	2,809,384	2,680,742	12,686,680	5,894,708	2,380,558	2,303,940	10,579,207
Mar	7,510,358	2,467,175	2,730,454	12,707,988	6,041,789	2,776,439	2,608,928	11,427,156
Apr	6,623,238	2,027,200	2,662,761	11,313,199	6,295,762	2,288,554	2,510,193	11,094,509
May	7,144,854	2,381,825	2,902,093	12,428,772	7,737,941	2,565,938	2,920,900	13,224,778
Jun	9,845,466	2,558,697	2,996,041	15,400,204	8,403,449	2,020,919	3,098,377	13,522,745
Jul	10,160,922	2,690,836	3,306,340	16,158,098				
Aug	8,566,032	2,057,281	2,907,427	13,530,739				
Sep	8,829,765	2,198,858	2,561,534	13,590,157				
Oct	7,140,856	2,514,963	2,388,186	12,044,005				
Nov	6,739,882	2,704,677	2,949,889	12,394,448				
Dec	7,646,566	2,606,633	2,629,846	12,883,045				
Total	48,118,702	15,505,690	17,079,774	80,704,166	41,714,317	14,528,729	16,221,477	72,464,523
Share of Deviations	59.6%	19.2%	21.2%	100.0%	57.6%	20.0%	22.4%	100.0%

Real-time load, real-time exports, and deviations in each region are shown in Table 3-11. RTO deviations are defined as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Table 3-11 Regional charges determinants (MWh): January through June 2012 (See 2011 SOM, Table 3-4)

	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
RTO	370,910,316	12,356,232	383,266,547	41,714,317	14,528,729	16,221,477	72,464,523
East	174,227,592	4,760,645	178,988,237	24,298,361	8,657,629	6,977,795	39,933,786
West	196,682,724	7,595,587	204,278,311	17,252,561	5,841,974	9,243,681	32,338,217

Operating Reserve Credits by Category

Table 3-12 shows the totals for each credit category for the first six months of 2011 and 2012. During the first six months of 2012, 85.0 percent of total operating reserve credits were in the balancing energy market category, which includes the balancing generator, real-time transactions, and lost opportunity cost credits. This percentage increased 3.1 percentage points from the 81.9 percent for the first six months of 2011.

Table 3-12 Credits by operating reserve category: January through June 2011 and 2012 (See 2011 SOM, Table 3-12)

Category	Jan-Jun 2011	Jan-Jun 2012	Change	Percentage Change	Jan-Jun 2011 Share of Credits	Jan-Jun 2012 Share of Credits
Day-Ahead Generator	$47,639,185	$35,934,532	($11,704,654)	(24.6%)	17.8%	14.9%
Day-Ahead Transactions	$285,263	$554	($284,708)	(99.8%)	0.1%	0.0%
Synchronous Condensing	$376,898	$35,603	($341,295)	(90.6%)	0.1%	0.0%
Balancing Generator	$141,843,029	$128,153,478	($13,689,550)	(9.7%)	53.0%	53.3%
Balancing Transactions	$1,522,415	$41,223	($1,481,193)	(97.3%)	0.6%	0.0%
Lost Opportunity Cost	$68,831,663	$67,571,753	($1,259,910)	(1.8%)	25.7%	28.1%
Canceled Resources	$5,153,362	$3,275,144	($1,878,218)	(36.4%)	1.9%	1.4%
Local Constraints Control	$1,777,519	$5,421,848	$3,644,329	205.0%	0.7%	2.3%
Total	$267,429,335	$240,434,134	($26,995,200)	(10.1%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-13 shows the distribution of credits by unit type and type of operating reserve (each row sums to 100 percent). Credits to demand resources are not included.

Table 3-13 Credits by unit types (By operating reserve category): January through June 2012 (See 2011 SOM, Table 3-13)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Total
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Combined Cycle	37.2%	0.0%	56.8%	6.0%	0.0%	0.0%	$29,978,930
Combustion Turbine	3.7%	0.0%	26.1%	69.9%	0.0%	0.2%	$86,453,236
Diesel	0.7%	0.0%	44.6%	54.7%	0.0%	0.0%	$2,070,737
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Hydro	0.0%	0.0%	90.9%	0.0%	9.1%	0.0%	$267,183
Nuclear	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	$335,366
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Steam - Coal	18.0%	0.0%	73.8%	3.3%	0.0%	4.9%	$106,666,151
Steam - Others	20.9%	0.0%	76.4%	2.6%	0.0%	0.0%	$11,278,985
Wind	0.0%	0.0%	1.3%	2.4%	96.2%	0.0%	$3,341,770

Table 3-14 shows the distribution of credits for each operating reserve category received by each unit type (each column sums to 100 percent). Combined cycle units and conventional steam units fueled by coal received 84.4 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 91.1 percent of the lost opportunity cost credits. Wind units received 98.2 percent of the canceled resources credits.

Table 3-14 Credits by operating reserve category (By unit type): January through June 2012 (See 2011 SOM, Table 3-14)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Local Constraints Control
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	31.0%	0.0%	13.3%	2.7%	0.0%	0.0%
Combustion Turbine	8.9%	100.0%	17.6%	89.4%	1.1%	3.5%
Diesel	0.0%	0.0%	0.7%	1.7%	0.0%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.2%	0.0%	0.7%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	53.4%	0.0%	61.4%	5.2%	0.0%	96.5%
Steam - Others	6.6%	0.0%	6.7%	0.4%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.1%	98.2%	0.0%
Total	$35,934,532	$35,603	$128,153,478	$67,571,753	$3,275,144	$5,421,848

Table 3-15 shows the total credits by unit type for the first six months of 2011 and 2012. The reduction of the price spread between natural gas and coal prices resulted in an increase in operating reserve credits paid to steam turbines fueled by coal. In the first six months of 2012, 44.4 percent of all credits were paid to coal units, 21.8 percentage points more than the share in the first six months of 2011. In contrast, the share of total credits paid to gas fired combined cycles declined from 29.1 percent in the first six months of 2011 to 12.5 percent in the first six months of 2012.

Table 3-15 Credits by unit type: January through June 2011 and 2012 (New Table)

Unit Type	Jan-Jun 2011	Jan-Jun 2012	Change	Percentage Change	Jan-Jun 2011 Share of Credits	Jan-Jun 2012 Share of Credits
Battery	$0	$0	$0	0.0%	0.0%	0.0%
Combined Cycle	$77,355,459	$29,978,930	($47,376,529)	(61.2%)	29.1%	12.5%
Combustion Turbine	$95,583,214	$86,453,236	($9,129,977)	(9.6%)	36.0%	36.0%
Diesel	$9,956,522	$2,070,737	($7,885,785)	(79.2%)	3.7%	0.9%
Fuel Cell	$0	$0	$0	0.0%	0.0%	0.0%
Hydro	$232,020	$267,183	$35,163	15.2%	0.1%	0.1%
Nuclear	$289,427	$335,366	$45,939	15.9%	0.1%	0.1%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$59,968,213	$106,666,151	$46,697,938	77.9%	22.6%	44.4%
Steam - Others	$17,684,958	$11,278,985	($6,405,972)	(36.2%)	6.7%	4.7%
Wind	$4,551,845	$3,341,770	($1,210,076)	(26.6%)	1.7%	1.4%
Total	$265,621,657	$240,392,358	($25,229,299)	(9.5%)	100.0%	100.0%

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 will be based on the lesser of the LMP desired output and the forecasted output of the unit.[7]

Credits paid to wind units decreased in the first six months of 2012. In the first six months of 2012 the total was $3.3 million, lower than the $4.6 million paid in the first six months of 2011. Table 3-16 shows the monthly credits paid to wind units.

7 See "PJM Manual 28: Operating Agreement Accounting" Revision 52 (June 1, 2012), Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons.

Table 3-16 Credits paid to wind units: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-15)

	2011				2012			
	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Total	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Total
Jan	$0	$0	$468,059	$468,059	$0	$0	$741,979	$741,979
Feb	$0	$0	$182,151	$182,151	$0	$0	$517,612	$517,612
Mar	$0	$0	$344,622	$344,622	$0	$72	$1,098,130	$1,098,202
Apr	$0	$0	$271,810	$271,810	$20,990	$0	$409,047	$430,038
May	$0	$0	$2,446,129	$2,446,129	$23,212	$0	$448,836	$472,048
Jun	$0	$0	$839,074	$839,074	$817	$81,074	$0	$81,890
Jul	$0	$0	$167,310	$167,310				
Aug	$0	$0	$244,935	$244,935				
Sep	$0	$0	$151,194	$151,194				
Oct	$0	$0	$1,325,128	$1,325,128				
Nov	$0	$0	$2,336,582	$2,336,582				
Dec	$0	$0	$420,210	$420,210				
Total	$0	$0	$4,551,845	$4,551,845	$45,019	$81,145	$3,215,605	$3,341,770

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

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to the LMP at the unit. Noneconomic generation includes units that are producing energy but at an offer price higher than the LMP at the unit. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the day-ahead schedule or minimum run time.

The MMU analyzed the hours for which a unit received balancing generator operating reserve credits to determine which units are economic and noneconomic. Each unit was determined to be economic or noneconomic based solely on the unit's hourly energy offer, excluding the hourly no-load cost and any applicable startup cost. A unit could be economic for every hour during a segment, but still receive balancing generator operating reserve credits because LMP revenue did not cover the additional startup and hourly no-load costs.

Table 3-17 shows the number of economic and noneconomic hours for each unit type. For example, of the 12,594 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit's bus was higher than its real-time energy offer in 4,124 hours, or 32.7 percent of those hours.

Table 3-17 Economic vs. noneconomic hours: January through June 2012 (See 2011 SOM, Table 3-16)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	4,124	32.7%	8,470	67.3%	12,594
Combustion Turbine	2,411	29.3%	5,804	70.7%	8,215
Diesel	755	31.2%	1,666	68.8%	2,421
Hydro	0	0.0%	68	100.0%	68
Steam - Coal	11,470	19.4%	47,805	80.6%	59,275
Steam - Others	790	29.7%	1,868	70.3%	2,658
Wind	75	88.2%	10	11.8%	85
Total	19,625	23.0%	65,691	77.0%	85,316

Geography of Charges and Credits

Table 3-18 shows the geography of charges and credits in the first six months of 2012. Charges are categorized by the location (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 and resources in the AEP Control Zone paid 14.1 percent of all operating reserve charges, and resources were paid 23.6 percent of all operating reserve 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 3-18 also shows that 81.7 percent of all charges were allocated in control zones, 6.1 percent in hubs and 12.2 percent in interfaces.

Table 3-18 Geography of charges and credits: January through June 2012[8] (New Table)

Location		Charges	Credits	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$2,211,908	$1,997,894	($214,014)	0.9%	0.9%	0.2%	0.0%
	AEP	$33,165,948	$55,341,727	$22,175,779	14.1%	23.6%	0.0%	24.2%
	AP - DLCO	$21,033,991	$20,547,648	($486,344)	9.0%	8.7%	0.5%	0.0%
	ATSI	$15,216,642	$16,151,466	$934,824	6.5%	6.9%	0.0%	1.0%
	BGE - Pepco	$16,892,939	$38,614,990	$21,722,051	7.2%	16.4%	0.0%	23.7%
	ComEd - External	$31,288,719	$13,335,209	($17,953,509)	13.3%	5.7%	19.6%	0.0%
	DAY - DEOK	$11,477,206	$1,005,224	($10,471,982)	4.9%	0.4%	11.4%	0.0%
	Dominion	$13,343,740	$30,333,736	$16,989,997	5.7%	12.9%	0.0%	18.5%
	DPL	$5,116,165	$8,821,364	$3,705,199	2.2%	3.8%	0.0%	4.0%
	JCPL	$4,888,758	$1,313,556	($3,575,202)	2.1%	0.6%	3.9%	0.0%
	Met-Ed	$3,604,942	$2,093,578	($1,511,364)	1.5%	0.9%	1.6%	0.0%
	PECO	$9,127,662	$975,159	($8,152,503)	3.9%	0.4%	8.9%	0.0%
	PENELEC	$5,290,567	$8,562,364	$3,271,797	2.3%	3.6%	0.0%	3.6%
	PPL	$9,209,531	$2,997,983	($6,211,548)	3.9%	1.3%	6.8%	0.0%
	PSEG	$9,834,169	$32,843,011	$23,008,843	4.2%	14.0%	0.0%	25.1%
	RECO	$290,485	$0	($290,485)	0.1%	0.0%	0.3%	0.0%
	All Zones	$191,993,369	$234,934,907	$42,941,537	81.7%	100.0%	53.2%	100.0%
Hubs	AEP - Dayton	$1,657,544	$0	($1,657,544)	0.7%	0.0%	1.8%	0.0%
	Dominion	$333,466	$0	($333,466)	0.1%	0.0%	0.4%	0.0%
	Eastern	$490,862	$0	($490,862)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$255,400	$0	($255,400)	0.1%	0.0%	0.3%	0.0%
	Ohio	$85,169	$0	($85,169)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$31,896	$0	($31,896)	0.0%	0.0%	0.0%	0.0%
	Western	$11,417,167	$0	($11,417,167)	4.9%	0.0%	12.4%	0.0%
	All Hubs	$14,271,504	$0	($14,271,504)	6.1%	0.0%	15.5%	0.0%
Interfaces	IMO	$3,847,295	$0	($3,847,295)	1.6%	0.0%	4.2%	0.0%
	Linden	$735,414	$0	($735,414)	0.3%	0.0%	0.8%	0.0%
	MISO	$7,261,829	$0	($7,261,829)	3.1%	0.0%	7.9%	0.0%
	Neptune	$394,192	$0	($394,192)	0.2%	0.0%	0.4%	0.0%
	NIPSCO	$28,940	$0	($28,940)	0.0%	0.0%	0.0%	0.0%
	Northwest	$170,160	$0	($170,160)	0.1%	0.0%	0.2%	0.0%
	NYIS	$2,265,023	$0	($2,265,023)	1.0%	0.0%	2.5%	0.0%
	OVEC	$637,360	$0	($637,360)	0.3%	0.0%	0.7%	0.0%
	South Exp	$3,631,827	$0	($3,631,827)	1.5%	0.0%	4.0%	0.0%
	South Imp	$9,739,771	$0	($9,739,771)	4.1%	0.0%	10.6%	0.0%
	All Interfaces	$28,711,811	$41,777	($28,670,034)	12.2%	0.0%	31.2%	0.0%
Total		$234,976,684	$234,976,684	$0	100.0%	100.0%	100.0%	100.0%

8 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-18 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.

Table 3-19 and Table 3-20 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 3-19 shows that on average, 10.3 percent of balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 48.1 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-19 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through June 2012 (See 2011 SOM, Table 3-17)

	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	$620,429	$477,947	$1,177,834	$2,276,210	$11,746,947
Apr	$770,880	$532,718	$1,265,853	$2,569,452	$16,978,535
May	$1,352,346	$73,630	$2,002,468	$3,428,444	$20,329,142
Jun	$1,944,473	$65,193	$1,633,672	$3,643,338	$22,638,024
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
East Generators Total	$6,595,326	$1,665,019	$7,075,126	$15,335,471	$95,698,112
PJM Total Charges	$68,426,307	$10,009,960	$70,846,897	$149,283,163	$199,000,375
Share	9.6%	16.6%	10.0%	10.3%	48.1%

Table 3-20 also shows that generators in the Western Region paid 12.6 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 51.9 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-20 Monthly balancing operating reserve charges and credits to generators (Western Region): January through June 2012 (See 2011 SOM, Table 3-18)

	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	$827,463	$0	$1,515,079	$2,342,541	$17,113,158
Apr	$1,001,550	$139,080	$1,711,165	$2,851,795	$15,372,629
May	$1,755,059	$233,498	$2,427,157	$4,415,714	$22,218,866
Jun	$2,150,186	$129,772	$1,781,898	$4,061,856	$21,801,162
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
West Generators Total	$8,153,367	$817,446	$8,929,089	$17,899,901	$103,221,742
PJM Total Charges	$68,426,307	$2,956,753	$70,846,897	$142,229,957	$199,000,375
Share	11.9%	27.6%	12.6%	12.6%	51.9%

Table 3-21 shows that on average in the first six months of 2012, generator charges were 14.1 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 0.8 percentage points higher than the average of the first six months of 2011. Generators received 99.98 percent of all operating reserve credits, while the remaining 0.02 percent were credits paid to import transactions.

Table 3-21 Percentage of unit credits and charges of total credits and charges: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-19)

	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%	100.0%
Feb	11.8%	98.7%	11.8%	100.0%
Mar	12.9%	98.6%	14.1%	99.9%
Apr	15.5%	99.0%	15.3%	100.0%
May	16.0%	100.0%	15.5%	100.0%
Jun	13.4%	99.8%	15.0%	100.0%
Jul	16.6%	100.0%		
Aug	14.2%	100.0%		
Sep	13.1%	99.9%		
Oct	11.3%	99.8%		
Nov	12.8%	99.6%		
Dec	11.4%	99.9%		
Average	13.3%	99.3%	14.1%	100.0%

Load Response Resource Operating Reserve Credits

End-use customers or their representative may make demand reduction offers which include the day-ahead LMP above which the end-use customer would not consume, and which may also include shut-down costs. Payment for reducing load is based on the MWh reductions committed in the Day-Ahead market.

Total payments to end-use customers or their representative for accepted day-ahead Economic Load Response offers will not be less than the total load response offer, included any submitted shut-down costs. If total payments are less than the total value of the load response offer, PJM will made the resource whole through day-ahead operating reserve credits.

In real-time, reimbursement for reducing load is based on the actual MWh reduction in excess of committed day-ahead load reductions plus an adjustment for losses. In cases where load response is dispatched by PJM, the total payment to end-use customers or their representative will not be less than the total value of the load response offer, including any submitted shut-down costs. If total payments are less than the total value of the load response offer, PJM will make the resource whole through balancing operating reserve credits.

In the first six months of 2012, 9.1 percent of payments for demand reduction offers were covered by operating reserve credits while the remaining 90.9 percent were paid through the economic load response program. (Table 3-22)

Table 3-22 Day-ahead and balancing operating reserve for load response credits: Calendar year 2011 through June 2012 (See 2011 SOM, Table 3-20)

	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%	$8,664	$19,002	31.3%	68.7%
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	$0	100.0%	0.0%
Apr	$37,533	$17,796	67.8%	32.2%	$195,820	$3,807	98.1%	1.9%
May	$271,955	$130,162	67.6%	32.4%	$288,482	$24,996	92.0%	8.0%
Jun	$906,532	$3,932	99.6%	0.4%	$56,691	$1,640	97.2%	2.8%
Jul	$379,570	$539	99.9%	0.1%				
Aug	$87,943	$191	99.8%	0.2%				
Sep	$19,670	$0	100.0%	0.0%				
Oct	$48,863	$857	98.3%	1.7%				
Nov	$15,524	$0	100.0%	0.0%				
Dec	$45,102	$8,898	83.5%	16.5%				
Total	$1,456,324	$153,001	90.5%	9.5%	$571,399	$57,323	90.9%	9.1%

Reactive Service

Credits to resources providing reactive services are separate from operating reserve credits. These credits are divided into three categories. Reactive Service Credits are paid to units providing reactive services with an offer price higher than the LMP at the unit's bus. Reactive Service Lost Opportunity Cost Credits are paid to units reduced or suspended by PJM for reactive reliability purposes when their offer price is lower than the LMP at the unit's bus. Reactive Service Synchronous Condensing Credits are paid to units providing synchronous condensing for the purpose of maintaining the reactive reliability of the system. Reactive service charges are allocated daily to real-time load in the transmission zone where the reactive service was provided.

Total reactive service credits in the first six months of 2012 were $37.8 million, about 2.3 times higher than the $11.6 million in the first six months of 2011. Table 3-23 shows the monthly distribution of reactive service credits. This increase was in part a result of the need for reactive support in the ATSI Control Zone in the first quarter of 2012. The top three zones accounted for 62.6 percent of the total reactive costs, a decrease of 18.8 percentage points from the first six months of 2011 share. The top three control zones were DPL, JCPL and PENELEC.

Table 3-23 Monthly reactive service credits: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-21)

	2011	2012	Change	Percentage Change
Jan	$1,546,278	$2,920,441	$1,374,163	88.9%
Feb	$1,912,027	$13,108,018	$11,195,991	585.6%
Mar	$1,438,306	$6,731,994	$5,293,688	368.1%
Apr	$2,077,101	$4,517,496	$2,440,395	117.5%
May	$2,712,293	$5,396,852	$2,684,559	99.0%
Jun	$1,868,004	$5,134,500	$3,266,496	174.9%
Jul	$929,807			
Aug	$1,696,735			
Sep	$2,688,094			
Oct	$15,523,789			
Nov	$7,105,062			
Dec	$1,790,778			
Total	$11,554,009	$37,809,300	$26,255,291	227.2%

Table 3-24 shows the distribution of credits for each category of reactive service credit received by each unit type (each column sums to 100 percent). In the first six months of 2012 combined cycles and coal steam turbines received 84.6 percent of all credits, 5.3 percentage points higher than the share received in the first six months of 2011, combustion turbines received 11.7 percent, 6.1 percentage points lower than the share received in the first six months of 2011.

Table 3-24 Reactive service credits by unit type: January through June 2012 (See 2011 SOM, Table 3-22)

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Total Reactive Credits
Battery	0.0%	0.0%	0.0%	0.0%
Combined Cycle	21.3%	8.1%	0.0%	20.7%
Combustion Turbine	11.9%	1.7%	100.0%	11.7%
Diesel	2.3%	0.0%	0.0%	2.2%
Hydro	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%
Steam - Coal	63.1%	88.0%	0.0%	63.9%
Steam - Others	1.5%	2.2%	0.0%	1.5%
Wind	0.0%	0.0%	0.0%	0.0%
Total	$36,220,025	$1,485,089	$104,187	$37,809,300

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.

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 remains high, but decreased in the first six months of 2012 compared to the first six months of 2011. Table 3-25 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 26.0 percent of total operating reserve credits in the first six months of 2012, compared to 34.3 percent in the first six months of 2011. The top 20 units received 40.0 percent of total operating reserve credits in the first six months of 2012.

Table 3-25 Top 10 operating reserve credits units (By percent of total system): Calendar years 2001 through June 2012 (See 2011 SOM, Table 3-23)

	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	26.0%	0.7%

Table 3-18 shows the distribution of operating reserve credits to units by zone. The AEP Control Zone had the largest share of credits with 23.6 percent, the BGE and Pepco Control Zones combined had the second highest with 16.4 percent, and the PSEG Control Zone had the third highest with a 14.0 percent share.

Table 3-26 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories. The shares of the top 10 units in three of the categories: day-ahead generator, canceled resources and reactive services, were above 70.0 percent. The shares of the top 10 organizations in all categories separately were above 90.0 percent.

Table 3-26 Top 10 units and organizations operating reserve credits: January through June 2012 (New Table)

	Top 10 units		Top 10 organizations	
Category	Credits	Credits Share	Credits	Credits Share
Total Operating Reserves	$62,611,394	26.0%	$210,154,390	87.4%
Day-Ahead Generator	$22,828,875	63.5%	$34,439,102	95.8%
Synchronous Condensing	$28,373	79.7%	$35,603	100.0%
Balancing Generator	$47,708,068	37.2%	$117,017,096	91.3%
Canceled Resources	$2,572,219	78.5%	$3,208,271	98.0%
Lost Opportunity Cost	$24,278,585	35.9%	$62,951,130	93.2%
Reactive Services	$28,049,582	74.2%	$34,915,635	92.3%

Concentration of Operating Reserve Credits

In the first six months of 2012, concentration in all operating reserve credits categories was high.[9] Operating reserve credits HHI was calculated based on each organization's daily credits for each category. Table 3-27 shows the average HHI for each category. Day-ahead operating reserve credits HHI was 4402. Balancing operating reserve credits HHI averaged 2981. Lost opportunity cost credits HHI was 4002.

9 See the *2012 Quarterly State of the Market Report for PJM: January through June*, Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Table 3-27 Daily operating reserve credits HHI: January through June 2012 (See 2011 SOM, Table 3-34)

	Daily Operating Reserve Credits HHI							
	Day-Ahead Generators	Day-Ahead Transactions	Synchronous Condensing	Balancing Generators	Balancing Transactions	Lost Opportunity Cost	Canceled Resources	Total Credits
Average	4402	10000	10000	2981	10000	4002	4798	1758
Minimum	1296	10000	10000	1089	10000	614	1009	643
Maximum	10000	10000	10000	5379	10000	10000	10000	4141
Highest market share (One day)	0.0%	100.0%	100.0%	71.0%	100.0%	100.0%	100.0%	61.1%
Highest market share (All days)	33.8%	60.3%	98.8%	32.3%	100.0%	33.3%	37.6%	20.3%
Numbers of Days	181	3	5	182	44	182	76	182
Days with HHI > 1,800	173	3	5	172	44	165	63	73
% of Days with HHI > 1,800	95.6%	100.0%	100.0%	94.5%	100.0%	90.7%	82.9%	40.1%
Days with HHI = 10,000	4	3	5	0	44	1	17	0
% of Days with HHI = 10,000	2.2%	100.0%	100.0%	0.0%	100.0%	0.5%	22.4%	0.0%

Table 3-28 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first six months of 2012, 41.1 percent of all credits paid to these units were allocated to deviations while the remaining 58.9 percent were paid for reliability reasons.

Table 3-28 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through June 2012 (See 2011 SOM, Table 3-35)

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$399,688	$881,265	$26,830,556	$17,218,090	$2,378,468	$0	$47,708,068
Share	0.8%	1.8%	56.2%	36.1%	5.0%	0.0%	100.0%

Lost Opportunity Cost Credits

In the first six months of 2012, lost opportunity cost credits decreased by 1.8 percent, after increasing by 57.5 percent in the first quarter of 2012. In the first six months of 2012 lost opportunity cost credits decreased by $1.3 million compared to the first six months of 2011.

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine is scheduled to operate in the day-ahead market but not dispatched by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus any balancing spot energy market charge that the unit will have to pay. 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 the lost opportunity cost based on the desired output.

Units in PJM receive lost opportunity cost credits when they are scheduled in day-ahead and not called in real-time. Table 3-29 shows the generation scheduled in day-ahead and requested by PJM to run in real-time, which did not receive lost opportunity cost credits, and the generation scheduled in day-ahead and not requested by PJM to run in real-time which did receive lost opportunity cost credits. In the first six months of 2012, 81.6 percent of the balancing operating reserve lost opportunity cost credits were paid to units scheduled to operate in the day-ahead market but not dispatched by PJM in real-time. This percentage increased 35.8 percentage points from the first six months of 2011. The remaining 18.4 percent were paid to units generating in real time with an offer price lower than the LMP at the units' bus which were reduced or suspended by PJM.

Table 3-29 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits (MWh): Calendar years 2011 and 2012 (See 2011 SOM, Table 3-37)

	2011			2012		
	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time
Jan	275,760	95,581	25.7%	374,432	435,817	53.8%
Feb	162,112	112,480	41.0%	218,169	604,164	73.5%
Mar	194,902	259,191	57.1%	141,590	961,494	87.2%
Apr	552,282	195,756	26.2%	264,284	1,303,421	83.1%
May	284,878	327,195	53.5%	144,700	1,101,824	88.4%
Jun	390,255	583,220	59.9%	137,164	1,280,907	90.3%
Jul	750,009	1,062,992	58.6%			
Aug	473,767	670,157	58.6%			
Sep	535,850	517,009	49.1%			
Oct	486,057	353,148	42.1%			
Nov	337,770	335,596	49.8%			
Dec	224,676	202,880	47.5%			
Total	1,860,189	1,573,423	45.8%	1,280,338	5,687,626	81.6%

Table 3-30 shows the distribution by zone of the generation not called in real time receiving lost opportunity cost credits. In the first six months of 2012, the top three control zones, AP, ATSI and Dominion combined for 67.8 percent of all the generation not called in real-time receiving lost opportunity cost credits.

Table 3-30 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits by zone (MWh): January through June 2012 (See 2011 SOM, Table 3-38)

Zone	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested in Real-Time	Share of Day-Ahead Generation Not Called in Real-Time
AECO - JCPL - PSEG - PECO	206,448	120,145	2.1%
AEP - DAY - DEOK	90,594	644,709	11.3%
AP - DLCO	10,647	1,189,864	20.9%
ATSI - PENELEC	233,908	1,091,141	19.2%
BGE - DPL - Dominion - Pepco	602,214	1,760,921	31.0%
ComEd - External	53,024	842,123	14.8%
Met-Ed - PPL	83,503	38,723	0.7%
Total	1,280,338	5,687,626	100.0%

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.[10] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU has not recommended these to the MIC for consideration.

- 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. This is one of the recommendations made to the MIC.
- 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 market, such units receive operating reserve credits equal to the difference between the unit's offer (including start up and no load

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

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 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.

- 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 desired or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between LMP and the offer curve) when calculating the lost opportunity cost in the energy market 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.
- 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 start up 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 energy offer is subtracted in order to calculate the actual value of the opportunity lost by the unit. This is one of the recommendations made to the MIC.

Table 3-31 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for the first six months of 2012, for the two categories of lost opportunity cost credits. Energy market lost opportunity cost credits would have been reduced by $15.6 million, or 23.1 percent, if all these changes had been implemented.[11]

Table 3-31 Impact on energy market lost opportunity cost credits of rule changes: January through June 2012 (New Table)

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$4,976,942	$62,594,811	$67,571,753
Impact 1: Committed Schedule	$378,708	$17,682,358	$18,061,066
Impact 2: Eliminating DA LMP	NA	($356,886)	($356,886)
Impact 3: Using Offer Curve	($264,991)	$6,187,454	$5,922,463
Impact 4: Including No Load Cost	NA	($38,489,199)	($38,489,199)
Impact 5: Including Startup Cost	NA	($725,043)	($725,043)
Net Impact	$113,717	($15,701,316)	($15,587,599)
Credits After Changes	$5,090,659	$46,893,495	$51,984,154

Table 3-32 shows the impact of each of the proposed modifications made jointly by PJM and the MMU. Energy market lost opportunity cost credits would have been reduced by $19.7 million, or 29.2 percent, if the two proposed modifications had been implemented.

Table 3-32 Impact on energy market lost opportunity cost credits of proposed rule changes: January through June 2012 (New Table)

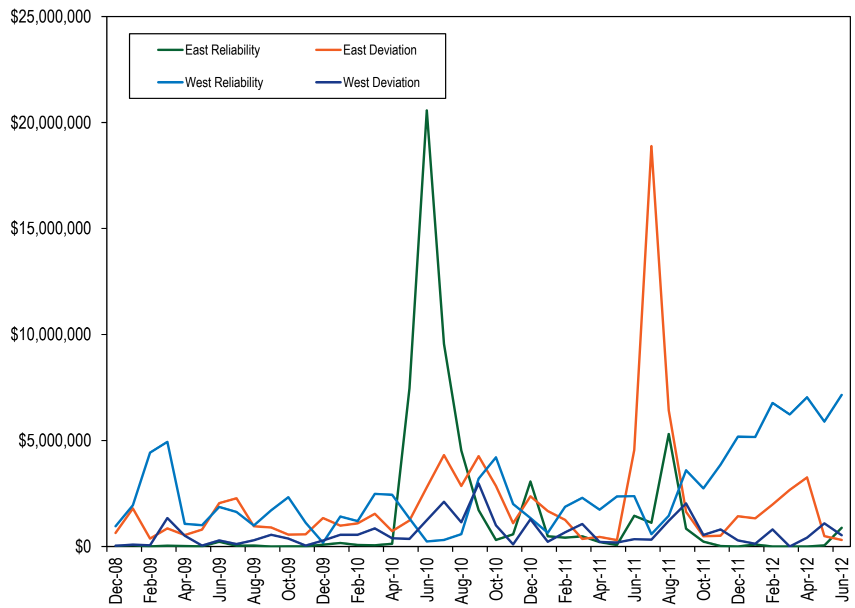
	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$4,976,942	$62,594,811	$67,571,753
Impact 1: Committed Schedule	$378,708	$17,682,358	$18,061,066
Impact 2: Including No Load Cost	NA	($37,122,696)	($37,122,696)
Impact 3: Including Startup Cost	NA	($673,074)	($673,074)
Net Impact	$378,708	($20,113,412)	($19,734,705)
Credits After Changes	$5,355,650	$42,481,398	$47,837,048

11 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.

Regional Credits Allocation

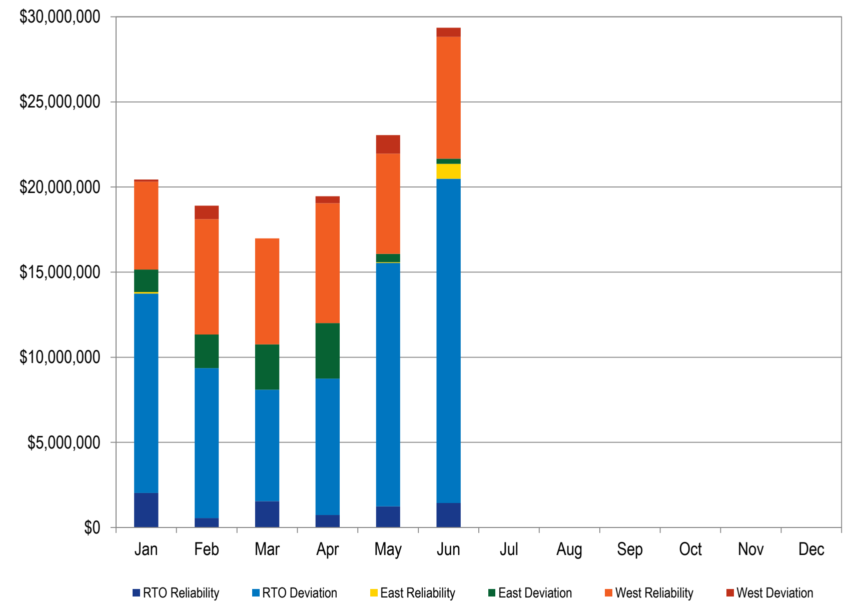
Figure 3-5 shows the regional reliability and regional deviation credits since the introduction of the new operating reserve rules on December 1, 2008. The figure shows the impact of the regional allocation of balancing operating reserve credits during events that only affect a specific region. High east reliability credits during the summer of 2010 were due to transmission maintenance on a 230 kV line, while high east deviations credits during the summer of 2011 were the result of high load levels during the peak months. The increase in west reliability credits since December 2011 was the result of credits paid to units providing black start and voltage support.

Figure 3-5 Monthly regional reliability and deviations credits: December 2008 through June 2012[12] (See 2011 SOM, Figure 3-5)



One of the purposes of the operating reserve rules implemented on December 1, 2008, was to allocate reliability charges to those requiring additional resources to maintain system reliability, defined to be real-time load and exports. In the first six months of 2012, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In the first six months of 2012, $46.8 million of reliability charges were allocated to participants serving real-time load and exports, which would have been charged to deviations under the prior rules. Figure 3-6 and Table 3-33 show how reliability credits were allocated across the RTO, Eastern and Western Regions.

Figure 3-6 Monthly balancing operating reserve categories: January through June 2012 (See 2011 SOM, Figure 3-6)



12 Credits in this figure do not include additional balancing operating reserve credits, such as lost opportunity cost, canceled resources or resources controlling local constraints control.

Table 3-33 Monthly balancing operating reserve categories: January through June 2012 (See 2011 SOM, Table 3-39)

	Reliability Credits			Deviation Credits		
	RTO	East	West	RTO	East	West
Jan	$2,031,032	$90,844	$5,165,990	$11,706,317	$1,323,039	$123,612
Feb	$549,422	$0	$6,769,404	$8,811,063	$1,975,509	$801,761
Mar	$1,543,774	$0	$6,228,575	$6,552,059	$2,662,899	$0
Apr	$731,845	$0	$7,038,913	$8,016,695	$3,258,059	$413,975
May	$1,239,772	$47,772	$5,890,042	$14,296,294	$485,574	$1,086,972
Jun	$1,437,983	$881,265	$7,155,048	$19,043,880	$304,880	$530,432
Jul						
Aug						
Sep						
Oct						
Nov						
Dec						
Total	$7,533,828	$1,019,881	$38,247,973	$68,426,307	$10,009,960	$2,956,753

Con-Ed – 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.[13] 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.

Black Start and Voltage Support Units

Certain units located in the Western Region zone 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 recommends that PJM dispatchers explicitly log the reasons that these units are run out-of-merit to comply with black start requirements or voltage support in order to correctly assign the associated charges.

Credits categorized as reliability paid to units in the Western Region increased considerably in the first six months of 2012 compared to the first six months of 2011 because of these units used for black start and voltage support

Up-to Congestion Transactions

Up-to congestion transactions do not pay balancing operating reserve charges. The MMU calculated the impact on balancing 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 the first six months of 2012, 49.9 percent of all up-to congestion transactions were profitable.[14]

In order to address the reaction of participants using up-to congestion transactions to an allocation of operating reserve charges and the associated impact on profitability, 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 proportional distribution of profitable and unprofitable transactions after paying operating reserve charges as actually occurred when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, it would be reasonable to expect that some transactions would not be made if such charges were assigned. The result is that only 29.3 percent of all up-to congestion transactions would have been made if such transactions had to pay operating reserve charges and the proportional distribution of profitable and unprofitable transactions remained the same. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

13 See the *2011 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.

14 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.

Table 3-34 shows the impact that including the identified 29.3 percent of up-to congestion transactions in the allocation of balancing operating reserve charges would have had on the operating reserve charge rates in the first six months of 2012. For example, the RTO deviations rate would have been reduced by 56.8 percent.

Table 3-34 Up-to Congestion Transactions Impact on the Operating Reserve Rates: January through June 2012 (See 2011 SOM, Table 3-44)

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.089	0.080	(0.009)	(10.6%)
RTO Deviations	0.944	0.408	(0.537)	(56.8%)
East Deviations	0.251	0.150	(0.100)	(40.0%)
West Deviations	0.091	0.029	(0.062)	(68.0%)
Lost Opportunity Cost	0.932	0.403	(0.530)	(56.8%)
Canceled Resources	0.045	0.020	(0.026)	(56.8%)

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[15] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including start up and no load 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 reserve. 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 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 the first six months of 2012, units providing reactive services were paid $15.2 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 95.5 percent were paid by deviations in the RTO Region, 4.1 percent by real-time load and real-time exports in the RTO Region and the remaining 0.4 percent by real-time load and real-time exports in the Western Region.

Table 3-35 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-35 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): January through June 2012 (New Table)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Credits to Units Providing Reactive Services	Current	($/MWh)	Percentage
Reliability	RTO	0.018	0.020	0.002	9.1%
	East	0.006	0.006	0.000	0.0%
	West	0.187	0.187	0.000	0.1%
Deviation	RTO	0.744	0.944	0.200	26.9%
	East	0.251	0.251	0.000	0.0%
	West	0.091	0.091	0.000	0.0%

15 OA Schedule 1 § 3.2.3B(f).