SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2009. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Overall, through the first nine months of 2009, net revenue results were mixed compared to the same period in 2008. For the new entrant combustion turbine (CT), nine zones had lower net revenue and eight zones had higher net revenue compared to 2008. (Table 3-8) All zones had lower energy net revenue compared to 2008 for the new entrant CT, however, for zones that cleared in the RTO Locational Delivery Area (LDA) for the 2007/2008 and the 2008/2009 BRA, this decrease in energy net revenue was more than offset by higher capacity revenues in the 2008/2009 delivery year. For the new entrant combined cycle (CC), eleven zones had lower net revenue and six zones had higher net revenue compared to 2008, which reflects a decrease in energy market revenue in all zones, a decrease in capacity revenue in most eastern zones, and an increase in capacity revenues in western zones which more than offset lower energy net revenues in AEP, AP, ComEd, DAY and DLCO and PENELEC. For the new entrant coal plant (CP), all zones had a significant decrease in net revenue compared to 2008, which is driven by lower energy revenues.

  The levels of net revenue through September of 2009 for new peaking, midmerit and baseload power plants vary significantly by location. Energy market prices and delivered fuel prices are down from the same period in 2008, although the spread between fuel costs and energy market prices varies by location. In western zones, energy market prices decreased less than in eastern zones, and, as a result, eastern zones show a more significant decrease in net revenue for the CT and the CC technology compared to western zones. The decrease in net revenues for the CP technology in all zones reflects the fact that energy prices decreased more than the delivered price of coal compared to the same period in 2008. Capacity market revenues also show mixed results for the first nine months of 2009 compared to the same period in 2008. Zones in the RTO LDA show an increase in capacity revenues from the same period in 2008 as the RTO cleared significantly higher in the 2008/2009 BRA and the 2009/2010 BRA compared to the 2007/2008 BRA. Some zones in the east show a decrease in capacity revenues from the same period in 2008 as the 2007/2008 auction cleared at a higher price for eastern zones than the 2008/2009 auction. When capacity market revenues for the full year 2009 are reflected, all control zones will show an increase in capacity revenue compared to calendar year 2008. The results from January through September of 2009 illustrate that the profitability of, and thus the incentive to invest in power generation technologies is closely tied to changes in the spread between electricity market prices and input fuel market prices in specific locations. In addition, 2009 results highlight the importance of revenues from the capacity market when energy market net revenues are insufficient to recover fixed costs.

  Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives. While the 2009 net revenue using PJM real-time average locational marginal prices was $39,920 per MW-year for a CT, the zonal maximum net revenue was $70,637 in the Pepco Control Zone and the minimum was $30,105 in the ComEd Control Zone.[1] While the PJM average net revenue in 2009 was $67,705 per MW-year for a CC, the zonal maximum net revenue was $110,937 in the Pepco Control Zone and the minimum was $50,495 in the ComEd Control Zone. While the PJM average net revenue in 2008 was $77,054 per MW-year for a CP, the zonal maximum net revenue was $146,463 in the Pepco Control Zone and the minimum was $54,209 in the DAY Control Zone.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through September 30, 2009, PJM installed capacity resources rose slightly from 164,899 MW on January 1 to 167,269 MW on September 30.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of September 2009, 40.7 percent was coal; 29.2 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During January through September 2009, coal provided 50.3 percent, nuclear 35.8 percent, natural gas 10.1 percent, heavy oil 0.2 percent, hydroelectric 2.0 percent, solid waste 0.6 percent, miscellaneous 0.2 percent, landfill gas 0.2 percent, and wind 0.7 percent of total generation.

- **Planned Generation.** If current trends continue, it is expected that older steam units in the east will be replaced by units burning natural gas and the result has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Scarcity Pricing Events in 2009.** PJM did not declare a scarcity event in the first three quarters of 2009.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher offers are required to meet demand, prices increase.

  When available capacity is not sufficient to maintain reserves, system operators have to implement emergency measures to maintain reliable service. These emergency measures include voltage reductions, emergency energy purchases and calling on maximum emergency resources. All of these actions are designed preserve the level of reserves needed to maintain system reliability.

  Under the current PJM rules, administrative scarcity pricing results when PJM takes specific, non market, emergency administrative actions to maintain system reliability under conditions of high load in pre-specified areas within PJM. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

- **Scarcity.** A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Thus, the energy market alone frequently does not directly compensate some of the resources needed to provide for reliability.

  Scarcity revenues to generation owners can come from a combination of energy and capacity markets or they can come entirely from capacity markets. The RPM capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed modification of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.

1 Calculated values shown in Section 3, "Energy Market, Part 2," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, energy market design should permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs under well defined conditions with transparent and verifiable triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. With a capacity market design that appropriately reflects scarcity rents in the energy market through an offset mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

Like an administrative energy market scarcity pricing mechanism, a capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit offset mechanism to remove those revenues from capacity market revenues or to ensure that the energy market scarcity revenues are not paid to capacity resources. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

- **Modifications to Scarcity Pricing.** While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, PJM's scarcity pricing rules need refinement.

The current single scarcity price signal should be replaced by locational signals. Locational scarcity signals could be implemented via ten minute reserve requirements modeled as constraints within reserve requirement regions, with administrative scarcity penalty factors, in the security constrained dispatch. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes.

The objective should be to create a system that recognizes scarcity in needed reserves, that redispatches units to maintain needed reserves and to meet the need for energy and that provides market signals consistent with this redispatch and with any failure to maintain needed reserves.

The reserve requirement mechanism should use clearly defined reserve targets and accurate measurement of the resources available to meet those requirements. Accurate measurement of available resources is an essential element of a reserve requirement based scarcity pricing mechanism. Without accurate measurement of available reserves, any mechanism designed to dispatch the system to maintain reserves will be compromised in both efficiency and effectiveness. PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism as current measures are not adequate. To be effective, operators will need accurate, real time data on unit availability and capabilities, including better data on ramp rates and ambient temperature adjustments.

Any scarcity pricing mechanism should also include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.

To avoid market power, the provision of reserves must continue to be based on unit characteristics included in a participant's energy offers, not on the basis of separate offers to provide reserves. Allowing for separate energy and reserve offers would create inconsistent parameters, which would prevent the direct substitutability of unit capabilities between reserves and energy and create the potential for the exercise of market power.

The reserve penalty factor curve methodology also requires a mechanism to eliminate the effect of non-market administrative emergency measures used during scarcity situations. In the absence of such a mechanism, emergency actions would result in lower prices in the presence of worsening scarcity conditions. The mechanism would increase the reserve requirement by the amount of resources that result from the emergency actions in order to maintain a market signal consistent with the level of scarcity absent the emergency action. In order to implement this mechanism, PJM will need accurate measurements of the impact of the emergency steps.

This mechanism should apply only to non-market emergency actions. The mechanism should not be applied to emergency resources that have been purchased and have a recognized market value, in particular maximum emergency generation, emergency load response and recallable capacity backed exports. Under conditions of potential and actual emergency, such resources should be recognized as energy or reserves. In addition, such inclusion eliminates the incentive to designate capacity as emergency or to export energy during emergency conditions and thereby force scarcity conditions and higher prices.

The reserve penalty factor curve approach permits the offset of scarcity revenues for capacity resources in an exact manner. In the reserve penalty factor curve approach, scarcity revenues result from a defined scarcity adder.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve 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. 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 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.

- **Operating Reserve Charges in 2009.** The level of operating reserve credits and corresponding charges decreased in the months of January through September by 30.7 percent compared to the months of January through September 2008. This decrease was comprised of a large decrease in the amount of balancing operating reserve credits, an increase in day-ahead credits, and a decrease of 29.0 percent in synchronous condensing credits.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.

- **Parameter Limited Schedule rules.** On March 19, 2009, the Commission issued an order rejecting PJM's proposed revisions to Section 6.6(c) of Schedule 1 of the PJM Operating Agreement that would have altered the application of the rules for evaluating requests for exceptions to the values included in or derived on a formulaic basis from the Parameter Limited Schedule Matrix.[2] As a consequence, the business rules approved by the Members Committee on November 15, 2007, were reinstated. PJM and the Market Monitor jointly administered these rules for the spring cycle.

2 126 FERC ¶61,251 (2009).

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs in well-defined stages with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity rents in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market.

In January through September of 2009, energy market revenues were lower as a result of lower energy prices in all zones compared to the same period in 2008. However, the cost of input fuels was also down significantly from the prior period, resulting in lower marginal costs for all technologies. The change in energy market net revenue is a function of the change in locational price levels and fuel costs. As a result, the change in energy market net revenue for the first nine months of 2009 compared to the first nine months of 2008 varies significantly by fuel type, technology and location.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in the first nine months of 2009. Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, or, when energy net revenues available for new entrants decreases rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when CTs set price based on gas costs. In January through September of 2009, with generally lower load levels, CTs ran less often, which reduced the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2009 Calendar Year PJM RPM auction-clearing capacity prices and capacity revenues by LDA and zone: Effective for January through September 2009 (See 2008 SOM, Table 3-3)

	Delivery Year 2008/2009			Delivery Year 2009/2010			RPM Revenue 2009
Zone	LDA	$/MW-Day	$/MW in 2009	LDA	$/MW-Day	$/MW in 2009	(Jan - Sep) $/MW
AECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
AEP	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
AP	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
BGE	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$28,954	$60,681
ComEd	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DAY	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DLCO	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
Dominion	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
JCPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
Met-Ed	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
PECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
PENELEC	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
Pepco	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$28,954	$60,681
PPL	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
PSEG	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
RECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
PJM	N/A	$124.58	$18,812	N/A	$138.46	$16,892	$35,703

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2009 (See 2008 SOM, Table 3-4)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$48,199	$45,810	(5%)
AEP	$19,856	$29,349	48%
AP	$19,856	$40,241	103%
BGE	$54,292	$60,681	12%
ComEd	$19,856	$29,349	48%
DAY	$19,856	$29,349	48%
DLCO	$19,856	$29,349	48%
Dominion	$19,856	$29,349	48%
DPL	$48,199	$45,810	(5%)
JCPL	$48,199	$45,810	(5%)
Met-Ed	$19,856	$40,241	103%
PECO	$48,199	$45,810	(5%)
PENELEC	$19,856	$40,241	103%
Pepco	$54,292	$60,681	12%
PPL	$19,856	$40,241	103%
PSEG	$48,199	$45,810	(5%)
RECO	$48,199	$45,810	(5%)
PJM	$28,588	$35,703	25%

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM (Dollars per MBtu): January through September 2008 and 2009 (See 2008 SOM, Table 3-6)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Natural Gas	$10.80	$4.67	(57%)
Low Sulfur Coal	$4.53	$3.23	(29%)

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$60,950	$9,926	(84%)
AEP	$4,695	$3,576	(24%)
AP	$20,690	$12,728	(38%)
BGE	$45,137	$13,083	(71%)
ComEd	$4,393	$2,751	(37%)
DAY	$5,124	$3,279	(36%)
DLCO	$7,785	$4,371	(44%)
Dominion	$37,629	$13,971	(63%)
DPL	$32,794	$12,358	(62%)
JCPL	$33,417	$10,084	(70%)
Met-Ed	$24,746	$9,122	(63%)
PECO	$25,716	$8,781	(66%)
PENELEC	$5,590	$3,552	(36%)
Pepco	$46,690	$15,361	(67%)
PPL	$20,717	$8,091	(61%)
PSEG	$27,633	$9,850	(64%)
RECO	$23,148	$8,441	(64%)
PJM	$12,445	$4,903	(61%)

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$136,158	$44,929	(67%)
AEP	$26,445	$25,240	(5%)
AP	$66,752	$50,300	(25%)
BGE	$120,486	$48,717	(60%)
ComEd	$26,228	$20,543	(22%)
DAY	$28,400	$25,433	(10%)
DLCO	$26,843	$24,883	(7%)
Dominion	$105,147	$51,278	(51%)
DPL	$102,291	$48,316	(53%)
JCPL	$111,689	$45,154	(60%)
Met-Ed	$88,762	$40,482	(54%)
PECO	$90,696	$40,367	(55%)
PENELEC	$38,602	$26,425	(32%)
Pepco	$120,454	$50,716	(58%)
PPL	$82,087	$38,245	(53%)
PSEG	$105,588	$47,849	(55%)
RECO	$95,823	$43,610	(54%)
PJM	$55,969	$29,614	(47%)

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through September 2008 and 2009 (See 2008 SOM, Table 3-7)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$309,767	$81,049	(74%)
AEP	$136,544	$41,463	(70%)
AP	$231,731	$81,877	(65%)
BGE	$282,747	$73,912	(74%)
ComEd	$182,016	$68,512	(62%)
DAY	$118,189	$26,274	(78%)
DLCO	$128,065	$51,590	(60%)
Dominion	$260,411	$68,799	(74%)
DPL	$287,512	$56,580	(80%)
JCPL	$293,173	$80,212	(73%)
Met-Ed	$257,848	$71,696	(72%)
PECO	$264,203	$76,509	(71%)
PENELEC	$214,546	$82,351	(62%)
Pepco	$298,582	$78,240	(74%)
PPL	$260,572	$79,695	(69%)
PSEG	$231,512	$103,097	(55%)
RECO	$280,621	$77,192	(72%)
PJM	$167,110	$43,763	(74%)

New Entrant Combustion Turbine

Table 3-7 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-10)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Energy	$12,445	$4,903	(61%)
Capacity	$25,477	$31,818	25%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,199	$1,199	0%
Total	$39,121	$37,920	(3%)

Table 3-8 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-11)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$105,103	$51,950	(51%)
AEP	$23,589	$30,929	31%
AP	$39,584	$49,788	26%
BGE	$94,719	$68,359	(28%)
ComEd	$23,287	$30,105	29%
DAY	$24,018	$30,632	28%
DLCO	$26,679	$31,725	19%
Dominion	$56,523	$41,325	(27%)
DPL	$76,947	$54,382	(29%)
JCPL	$77,570	$52,107	(33%)
Met-Ed	$43,640	$46,183	6%
PECO	$69,869	$50,804	(27%)
PENELEC	$24,484	$40,612	66%
Pepco	$96,272	$70,637	(27%)
PPL	$39,611	$45,152	14%
PSEG	$71,786	$51,874	(28%)
RECO	$67,301	$50,465	(25%)
PJM	$39,121	$37,920	(3%)

New Entrant Combined Cycle

Table 3-9 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-12)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Energy	$55,969	$29,614	(47%)
Capacity	$27,618	$34,492	25%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,599	$1,599	0%
Total	$85,186	$65,705	(23%)

Table 3-10 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-13)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$184,321	$90,783	(51%)
AEP	$47,226	$55,192	17%
AP	$87,533	$90,774	4%
BGE	$174,534	$108,938	(38%)
ComEd	$47,009	$50,495	7%
DAY	$49,181	$55,386	13%
DLCO	$47,624	$54,835	15%
Dominion	$125,929	$81,230	(35%)
DPL	$150,455	$94,170	(37%)
JCPL	$159,852	$91,008	(43%)
Met-Ed	$109,543	$80,957	(26%)
PECO	$138,859	$86,222	(38%)
PENELEC	$59,383	$66,900	13%
Pepco	$174,502	$110,937	(36%)
PPL	$102,869	$78,720	(23%)
PSEG	$153,751	$93,704	(39%)
RECO	$143,986	$89,465	(38%)
PJM	$85,186	$65,705	(23%)

New Entrant Coal Plant

Table 3-11 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-14)

	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
Energy	$167,110	$43,763	(74%)
Capacity	$25,774	$32,189	25%
Synchronized	$0	$0	0%
Regulation	$752	$210	(72%)
Reactive	$892	$892	0%
Total	$194,527	$77,054	(60%)

Table 3-12 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-15)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$355,209	$124,194	(65%)
AEP	$156,146	$69,792	(55%)
AP	$251,798	$120,187	(52%)
BGE	$333,659	$130,119	(61%)
ComEd	$202,313	$96,983	(52%)
DAY	$137,649	$54,209	(61%)
DLCO	$147,945	$80,119	(46%)
Dominion	$280,374	$96,873	(65%)
DPL	$332,986	$99,010	(70%)
JCPL	$338,536	$123,344	(64%)
Met-Ed	$277,699	$109,647	(61%)
PECO	$309,653	$119,671	(61%)
PENELEC	$234,601	$120,751	(49%)
Pepco	$349,584	$134,559	(62%)
PPL	$280,458	$117,901	(58%)
PSEG	$276,760	$146,463	(47%)
RECO	$326,057	$120,281	(63%)
PJM	$194,527	$77,054	(60%)

New Entrant Day-Ahead Net Revenues

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-16)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$24,969	$9,926	(60%)
AEP	$1,901	$3,576	88%
AP	$9,409	$12,728	35%
BGE	$27,451	$13,083	(52%)
ComEd	$1,863	$2,751	48%
DAY	$1,851	$3,195	73%
DLCO	$1,550	$4,371	182%
Dominion	$18,344	$13,971	(24%)
DPL	$18,643	$12,358	(34%)
JCPL	$14,060	$10,084	(28%)
Met-Ed	$12,655	$9,122	(28%)
PECO	$12,734	$8,781	(31%)
PENELEC	$4,465	$3,552	(20%)
Pepco	$29,223	$15,361	(47%)
PPL	$10,412	$8,091	(22%)
PSEG	$13,858	$9,850	(29%)
RECO	$11,521	$8,441	(27%)
PJM	$6,644	$1,896	(71%)

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-17)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$97,526	$44,929	(54%)
AEP	$20,861	$25,240	21%
AP	$53,132	$50,300	(5%)
BGE	$105,588	$48,717	(54%)
ComEd	$21,635	$20,543	(5%)
DAY	$21,322	$25,399	19%
DLCO	$16,049	$24,883	55%
Dominion	$87,683	$51,278	(42%)
DPL	$86,229	$48,316	(44%)
JCPL	$97,496	$45,154	(54%)
Met-Ed	$74,945	$40,482	(46%)
PECO	$74,654	$40,367	(46%)
PENELEC	$35,689	$26,425	(26%)
Pepco	$108,603	$50,716	(53%)
PPL	$68,759	$38,245	(44%)
PSEG	$93,059	$47,849	(49%)
RECO	$84,920	$43,610	(49%)
PJM	$43,044	$27,186	(37%)

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-18)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$293,296	$81,049	(72%)
AEP	$135,380	$41,463	(69%)
AP	$226,934	$81,877	(64%)
BGE	$283,802	$73,912	(74%)
ComEd	$187,687	$68,512	(63%)
DAY	$114,894	$26,818	(77%)
DLCO	$131,603	$51,590	(61%)
Dominion	$254,955	$68,799	(73%)
DPL	$290,021	$56,580	(80%)
JCPL	$295,885	$80,212	(73%)
Met-Ed	$261,220	$71,696	(73%)
PECO	$270,026	$76,509	(72%)
PENELEC	$226,578	$82,351	(64%)
Pepco	$301,912	$78,240	(74%)
PPL	$264,827	$79,695	(70%)
PSEG	$232,779	$103,097	(56%)
RECO	$283,203	$77,192	(73%)
PJM	$162,107	$41,054	(75%)

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009 (Jan - Sep)	$4,903	$1,896	$3,007	61%

Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-20)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009 (Jan - Sep)	$29,614	$27,186	$2,428	8%

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2008 and January through September 2009 (See 2008 SOM, Table 3-21)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009 (Jan - Sep)	$43,763	$41,054	$2,709	6%

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2008 SOM, Table 3-22)

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640
CC	$93,549	$99,230	$143,600	$171,361
CP	$208,247	$267,792	$359,750	$492,780

Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-24)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$105,103	$51,950	$123,640	85%	42%
AEP	$23,589	$30,929	$123,640	19%	25%
AP	$39,584	$49,788	$123,640	32%	40%
BGE	$94,719	$68,359	$123,640	77%	55%
ComEd	$23,287	$30,105	$123,640	19%	24%
DAY	$24,018	$30,632	$123,640	19%	25%
DLCO	$26,679	$31,725	$123,640	22%	26%
Dominion	$56,523	$41,325	$123,640	46%	33%
DPL	$76,947	$54,382	$123,640	62%	44%
JCPL	$77,570	$52,107	$123,640	63%	42%
Met-Ed	$43,640	$46,183	$123,640	35%	37%
PECO	$69,869	$50,804	$123,640	57%	41%
PENELEC	$24,484	$40,612	$123,640	20%	33%
Pepco	$96,272	$70,637	$123,640	78%	57%
PPL	$39,611	$45,152	$123,640	32%	37%
PSEG	$71,786	$51,874	$123,640	58%	42%
RECO	$67,301	$50,465	$123,640	54%	41%
PJM	$39,121	$37,920	$123,640	32%	31%

Figure 3-1 New entrant CT zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-3)

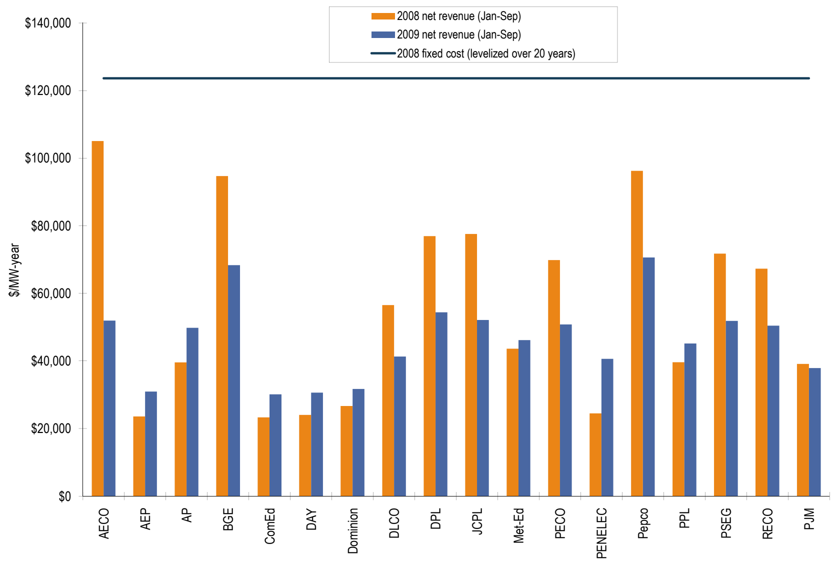


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-26)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$184,321	$90,783	$171,361	108%	53%
AEP	$47,226	$55,192	$171,361	28%	32%
AP	$87,533	$90,774	$171,361	51%	53%
BGE	$174,534	$108,938	$171,361	102%	64%
ComEd	$47,009	$50,495	$171,361	27%	29%
DAY	$49,181	$55,386	$171,361	29%	32%
DLCO	$47,624	$54,835	$171,361	28%	32%
Dominion	$125,929	$81,230	$171,361	73%	47%
DPL	$150,455	$94,170	$171,361	88%	55%
JCPL	$159,852	$91,008	$171,361	93%	53%
Met-Ed	$109,543	$80,957	$171,361	64%	47%
PECO	$138,859	$86,222	$171,361	81%	50%
PE-NELEC	$59,383	$66,900	$171,361	35%	39%
Pepco	$174,502	$110,937	$171,361	102%	65%
PPL	$102,869	$78,720	$171,361	60%	46%
PSEG	$153,751	$93,704	$171,361	90%	55%
RECO	$143,986	$89,465	$171,361	84%	52%
PJM	$85,186	$65,705	$171,361	50%	38%

Figure 3-2 New entrant CC zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-5)

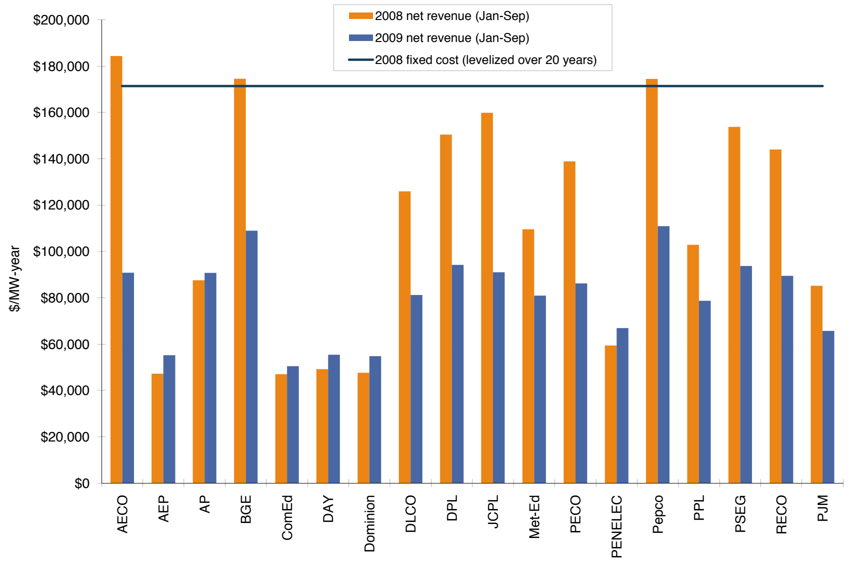


Figure 3-3 New entrant CP zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-7)

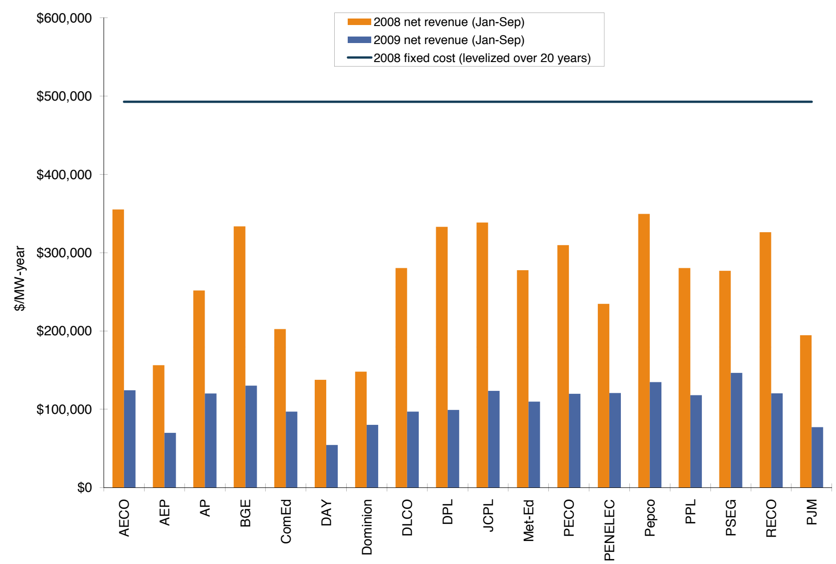


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Table 3-28)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	20-Year Levelized Fixed Cost	2008 Percent Recovery	2009 Percent Recovery
AECO	$355,209	$124,194	$492,780	72%	25%
AEP	$156,146	$69,792	$492,780	32%	14%
AP	$251,798	$120,187	$492,780	51%	24%
BGE	$333,659	$130,119	$492,780	68%	26%
ComEd	$202,313	$96,983	$492,780	41%	20%
DAY	$137,649	$54,209	$492,780	28%	11%
DLCO	$147,945	$80,119	$492,780	30%	16%
Dominion	$280,374	$96,873	$492,780	57%	20%
DPL	$332,986	$99,010	$492,780	68%	20%
JCPL	$338,536	$123,344	$492,780	69%	25%
Met-Ed	$277,699	$109,647	$492,780	56%	22%
PECO	$309,653	$119,671	$492,780	63%	24%
PENELEC	$234,601	$120,751	$492,780	48%	25%
Pepco	$349,584	$134,559	$492,780	71%	27%
PPL	$280,458	$117,901	$492,780	57%	24%
PSEG	$276,760	$146,463	$492,780	56%	30%
RECO	$326,057	$120,281	$492,780	66%	24%
PJM	$194,527	$77,054	$492,780	39%	16%

Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-23 PJM installed capacity (By fuel source): January 1, May 31, June 1, September 30, 2009 (See 2008 SOM, Table 3-30)[3, 4]

	1-Jan-09		31-May-09		1-Jun-09		30-Sep-09	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,064.7	40.7%	67,025.3	40.6%	68,159.0	40.7%	68,137.6	40.7%
Gas	48,333.9	29.3%	48,506.9	29.4%	48,979.3	29.2%	48,810.6	29.2%
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%	7,939.9	4.7%
Nuclear	30,478.0	18.5%	30,542.5	18.5%	30,701.5	18.3%	30,701.5	18.4%
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%	10,700.1	6.4%
Solid waste	664.7	0.4%	664.7	0.4%	672.1	0.4%	672.1	0.4%
Wind	166.4	0.1%	182.9	0.1%	297.8	0.2%	306.9	0.2%
Total	164,898.9	100.0%	165,146.7	100.0%	167,453.9	100.0%	167,268.7	100.0%

Energy Production by Primary Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through September 2009 (See 2008 SOM, Table 3-31)

	GWh	Percent
Coal	263,486.1	50.3%
Nuclear	187,626.8	35.8%
Natural Gas	52,694.5	10.1%
Hydroelectric	10,280.2	2.0%
Wind	3,446.5	0.7%
Solid Waste	3,125.5	0.6%
Miscellaneous	1,176.3	0.2%
Heavy Oil	1,127.0	0.2%
Landfill Gas	1,007.9	0.2%
Light Oil	156.5	0.0%
Kerosene	7.0	0.0%
Solar	2.9	0.0%
Biomass Gas	2.1	0.0%
Battery	0.1	0.0%
Jet Oil	0.0	0.0%
Total	524,139.5	100.0%

3 The capacity described in this section is the capability of all PJM capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

4 Wind-based resources accounted for 306.9 MW of installed capacity in PJM on September 30, 2009. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 13 percent factor. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Planned Generation Additions

Table 3-25 Year-to-year capacity additions: Calendar years 2000 through September 2009 (See 2008 SOM, Table 3-32)

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	702

PJM Generation Queues

Table 3-26 Queue comparison (MW): Calendar years 2009 vs. 2008 (See 2008 SOM, Table 3-33)

	MW in the Queue 2008	MW in the Queue 2009	Year-to-Year Change (MW)	Year-to-Year Change
2009	9,023	10,137	1,114	11%
2010	18,052	14,409	(3,642)	(25)%
2011	17,253	16,276	(977)	(6)%
2012	15,527	11,330	(4,198)	(37)%
2013	7,920	7,263	(657)	(9)%
2014	11,965	12,329	364	3%
2015	2,436	1,861	(575)	(31)%
2016	0	2,590	2,590	100%
2017	0	1,640	1,640	100%
2018	1,594	1,594	0	0%
Total	83,770	79,429	(4,341)	(5)%

Table 3-27 Capacity in PJM queues (MW): At September 30, 2009[5, 6] (See 2008 SOM, Table 3-34)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,121	0	17,347	25,468
B Expired 31-Jan-99	0	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	100	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	100	2,416	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	319	186	3,978	4,482
N Expired 31-Jan-05	1,462	2,133	138	6,663	10,397
O Expired 31-Jul-05	2,203	748	792	3,831	7,574
P Expired 31-Jan-06	2,321	816	1,761	3,588	8,486
Q Expired 31-Jul-06	3,226	707	4,339	6,433	14,705
R Expired 31-Jan-07	7,893	667	294	13,987	22,840
S Expired 31-Jul-07	7,671	760	1,689	10,773	20,892
T Expired 31-Jan-08	17,123	158	319	10,867	28,466
U Expired 31-Jan-09	16,241	89	30	18,473	34,833
V Expires 31-Jan-10	10,889	0	2	809	11,701
Total	69,048	23,031	10,381	185,737	288,197

5 The *2009 Quarterly State of the Market Report for PJM: January through September* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 3-28 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2009 (See 2008 SOM, Table 3-36)[7]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unkn	Total
AECO	0	767	4	0	0	81	665	1,066	0	2,582
AEP	1,035	594	2	100	84	25	3,673	10,321	53	15,888
AP	930	4	0	139	0	0	724	2,216	0	4,013
BGE	220	256	5	0	1,640	1	0	0	132	2,254
ComEd	1,680	1,044	94	0	392	0	1,326	23,988	44	28,568
DAY	0	10	2	0	0	20	12	897	0	941
DLCO	0	0	0	77	91	0	0	0	0	168
DPL	0	55	0	0	0	6	43	450	0	554
Dominion	3,521	181	31	30	1,944	20	425	230	0	6,382
JCPL	1,430	27	33	1	0	53	0	0	0	1,543
Met-Ed	1,745	122	26	0	24	10	10	0	0	1,937
PECO	1,830	45	6	0	180	1	18	0	1	2,081
PENELEC	0	65	18	32	0	0	50	1,827	0	1,993
Pepco	2,670	249	5	0	1,640	0	0	0	20	4,584
PPL	1,400	137	3	143	1,600	26	266	226	0	3,800
PSEG	1,225	822	3	0	0	91	0	0	0	2,141
Total	17,686	4,378	233	521	7,595	334	7,211	41,221	250	79,429

Table 3-29 Existing PJM capacity on September 30, 2009 (By zone and unit type (MW)) (See 2008 SOM, Table 3-37)

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	641	23	0	0	1,257	0	8	1,928
AEP	0	4,355	3,627	57	1,001	2,106	21,255	0	400	32,802
AP	0	1,129	1,140	36	108	0	7,974	0	245	10,632
BGE	0	0	862	7	0	1,735	2,942	0	0	5,546
ComEd	0	1,836	7,217	108	0	10,336	7,094	0	1,193	27,784
DAY	0	0	1,377	53	0	0	3,551	0	0	4,981
DLCO	0	0	0	0	6	1,741	1,259	0	0	3,006
DPL	0	364	2,487	95	0	0	2,016	0	0	4,962
Dominion	0	3,216	3,786	156	3,325	3,425	8,479	0	0	22,386
External	0	974	1,890	0	0	439	9,314	0	185	12,802
JCPL	0	1,078	1,430	25	400	615	318	0	0	3,865
Met-Ed	0	2,000	407	24	20	786	890	0	0	4,127
PECO	1	2,540	833	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	0	287	47	521	0	6,830	0	294	7,979
Pepco	0	0	1,454	9	0	0	4,829	0	0	6,292
PPL	0	960	1,352	63	571	2,275	5,830	0	217	11,268
PSEG	0	2,921	2,852	0	5	3,553	1,656	0	0	10,987
Total	1	21,373	31,640	711	7,599	31,499	87,621	3	2,542	182,988

Table 3-30 PJM capacity age (MW) (See 2008 SOM, Table 3-38)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,866	19,832	404	52	0	1,357	3	2,542	42,057
10 to 20	0	3,349	4,086	121	37	1,134	7,779	0	0	16,505
20 to 30	0	158	20	20	3,177	14,847	9,046	0	0	27,268
30 to 40	0	0	5,924	48	451	15,518	35,515	0	0	57,456
40 to 50	0	0	1,778	115	2,470	0	21,074	0	0	25,437
50 to 60	0	0	0	4	348	0	12,211	0	0	12,563
60 to 70	0	0	0	0	107	0	491	0	0	598
70 to 80	0	0	0	0	239	0	149	0	0	388
80 to 90	0	0	0	0	492	0	0	0	0	492
90 to 100	0	0	0	0	194	0	0	0	0	194
100 and over	0	0	0	0	32	0	0	0	0	32
Total	1	21,373	31,640	711	7,599	31,499	87,621	3	2,542	182,988

7 The unknown column includes MW data for units for which PJM has not provided the unit type.

Table 3-31 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2009 (See 2008 SOM, Table 3-39)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	4,485	1,716	46	1	180	232	726	1,516	1	8,902
Non-MAAC	7,166	1,833	129	346	2,511	65	6,160	37,651	97	55,959
SWMAAC	2,890	505	10	0	3,280	1	0	0	152	6,838
WMAAC	3,145	324	48	175	1,624	36	326	2,053	0	7,730
Total	17,686	4,378	233	521	7,595	334	7,211	41,221	250	79,429

Table 3-32 Comparison of generators 40 years and older with planned capacity additions (MW): Through 2018[8] (See 2008 SOM, Table 3-40)

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	1	2	0.0%
	Combined Cycle	0	0.0%	6,903	20.7%	4,485	11,388	29.8%
	Combustion Turbine	634	10.4%	8,242	24.7%	1,716	9,324	24.4%
	Diesel	49	0.8%	150	0.4%	46	147	0.4%
	Hydroelectric	2,042	33.4%	2,047	6.1%	1	2,048	5.4%
	Nuclear	0	0.0%	8,656	25.9%	180	8,836	23.1%
	Solar	0	0.0%	3	0.0%	232	235	0.6%
	Steam	3,384	55.4%	7,376	22.1%	726	4,717	12.3%
	Wind	0	0.0%	8	0.0%	1,516	1,524	4.0%
	EMAAC Total	6,109	100.0%	33,385	100.0%	8,902	38,220	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,510	10.1%	7,166	18,675	12.7%
	Combustion Turbine	631	2.5%	19,037	16.6%	1,833	20,239	13.8%
	Diesel	34	0.1%	409	0.4%	129	505	0.3%
	Hydroelectric	1,396	5.6%	4,440	3.9%	346	4,786	3.3%
	Nuclear	0	0.0%	18,047	15.8%	2,511	20,558	14.0%
	Solar	0	0.0%	0	0.0%	65	65	0.0%
	Steam	23,002	91.8%	58,926	51.5%	6,160	42,084	28.7%
	Wind	0	0.0%	2,023	1.8%	37,651	39,675	27.0%
	Unknown	0	0.0%	0	0.0%	97	97	0.1%
	Non-MAAC Total	25,063	100.0%	114,392	100.0%	55,959	146,684	100.0%

8 Percents shown in Table 3-32 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

(cont'd) Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
SWMAAC	Combined Cycle	0	0.0%	0	0.0%	2,890	2,890	9633.3%
	Combustion Turbine	315	9.0%	2,316	19.6%	505	2,506	16.5%
	Diesel	0	0.0%	16	54.8%	10	26	88.1%
	Nuclear	0	0.0%	1,735	14.7%	3,280	5,015	33.0%
	Solar	0	0.0%	0	0.0%	1	1	4.0%
	Steam	3,169	91.0%	7,770	65.6%	0	4,602	30.3%
	Unknown	0	0.0%	0	0.0%	152	152	1.0%
	SWMAAC Total	3,484	100.0%	11,837	100.0%	6,838	15,192	100.0%
WMAAC	Combined Cycle	0	0.0%	2,960	12.7%	3,145	6,105	23.0%
	Combustion Turbine	198	3.9%	2,046	8.8%	324	2,172	8.2%
	Diesel	35	0.7%	135	0.6%	48	147	0.6%
	Hydroelectric	444	8.8%	1,112	4.8%	175	1,286	4.9%
	Nuclear	0	0.0%	3,061	13.1%	1,624	4,685	17.7%
	Solar	0	0.0%	0	0.0%	36	36	0.1%
	Steam	4,370	86.6%	13,549	58.0%	326	9,505	35.9%
	Wind	0	0.0%	511	2.2%	2,053	2,564	9.7%
	WMAAC Total	5,047	100.0%	23,373	100.0%	7,730	26,500	100.0%
All Areas	Total	39,703		182,988		79,429	226,596	

Characteristics of Wind Units

Table 3-33 Capacity factor of wind units in PJM, January through September 2009[9] (New Table)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	24.9%	122,624	1,744
Capacity Resource	27.5%	69,361	798
All Units	26.0%	191,985	2,542

Table 3-34 Wind resources in Real-Time offering at a negative price in PJM, June through September 2009[10] (New Table)

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	83.0	85	0.15%
All Wind	828.9	473	0.81%

9 The corresponding table in the *2009 Quarterly State of the Market Report for PJM*, reversed the labels for energy-only resources and capacity resources data..

10 Units were permitted to submit negative price offers beginning June 1, 2009.

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through September 2009 (New Figure)

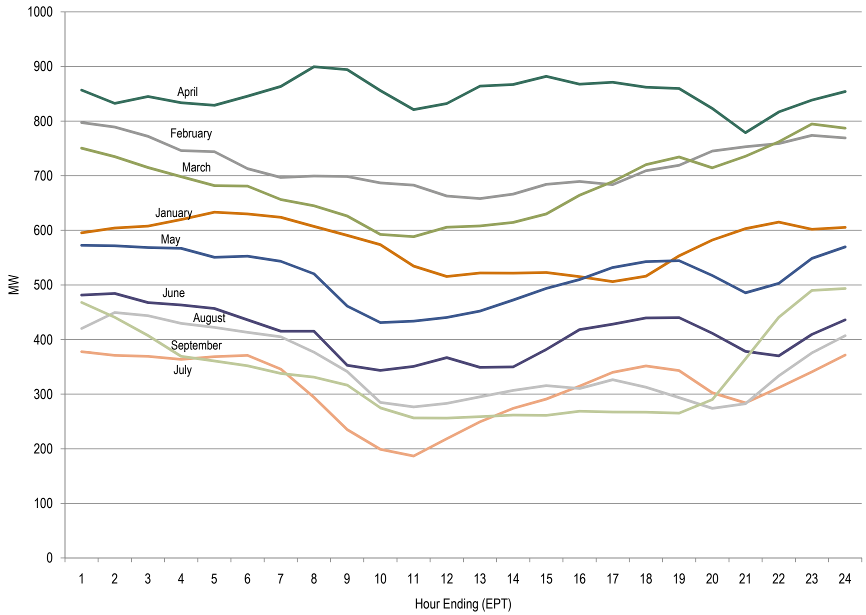


Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through September 2009 (New Figure)

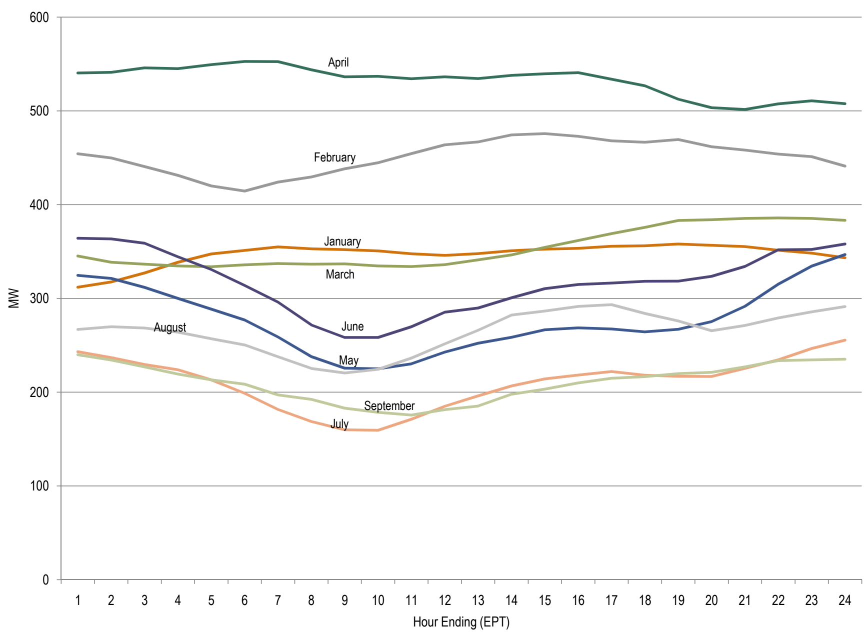
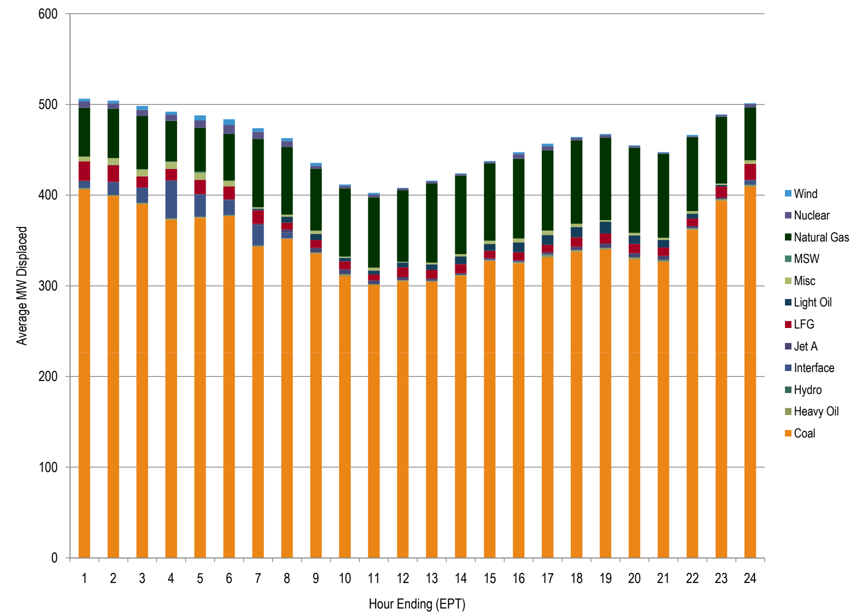


Figure 3-6 Marginal fuel displacement by wind generation in PJM, January through September 2009 (New Figure)



Operating Reserve

Overall Results

Table 3-35 Monthly operating reserve charges: January through September 2008 and 2009[11] (See 2008 SOM, Table 3-45)

	2008 (Jan-Sep) Charges				2009 (Jan-Sep) Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$4,126,221	$456,972	$39,935,491	$44,518,684	$9,260,150	$1,328,814	$30,001,637	$40,590,601
Feb	$3,731,017	$200,456	$23,165,838	$27,097,312	$7,434,068	$839,679	$16,508,010	$24,781,756
Mar	$2,904,498	$249,900	$18,916,241	$22,070,639	$9,549,963	$108,664	$25,945,310	$35,603,936
Apr	$4,213,578	$209,366	$22,559,577	$26,982,522	$6,998,364	$19,929	$13,246,434	$20,264,727
May	$10,873,205	$202,397	$22,970,363	$34,045,964	$6,024,108	$5,543	$15,476,784	$21,506,435
Jun	$7,064,877	$575,927	$65,597,311	$73,238,115	$6,722,329	$0	$19,224,687	$25,947,016
Jul	$7,038,834	$874,234	$48,041,415	$55,954,483	$8,210,636	$38,643	$17,312,974	$25,562,253
Aug	$6,140,554	$143,857	$26,212,547	$32,496,959	$7,697,174	$1	$20,711,506	$28,408,680
Sep	$4,581,147	$405,308	$27,809,898	$32,796,353	$6,057,598	$13,611	$13,450,468	$19,521,678
Total	$50,673,931	$3,318,419	$295,208,680	$349,201,030	$67,954,390	$2,354,884	$171,877,810	$242,187,084
Share of Annual Charges	14.5%	1.0%	84.5%	100.0%	28.1%	1.0%	71.0%	100.0%

Table 3-36 Regional balancing charges allocation: January through September 2008 and 2009[12] (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$3,432,227	$134,849	$3,567,076	$49,355,811	$28,883,393	$14,803,890	$93,043,094	$96,610,170
RTO	2.6%	0.1%	2.7%	37.9%	22.2%	11.4%	71.5%	74.2%
East	$393,809	$13,683	$407,492	$5,824,239	$3,067,879	$1,559,973	$10,452,090	$10,859,583
East	0.3%	0.0%	0.3%	4.5%	2.4%	1.2%	8.0%	8.3%
West	$18,628,965	$829,980	$19,458,945	$1,640,297	$1,080,901	$560,559	$3,281,757	$22,740,702
West	14.3%	0.6%	14.9%	1.3%	0.8%	0.4%	2.5%	17.5%
Total	$22,455,001	$978,512	$23,433,513	$56,820,347	$33,032,173	$16,924,422	$106,776,941	$130,210,454
Total	17.2%	0.8%	18.0%	43.6%	25.4%	13.0%	82.0%	100.0%

11 The balancing charges shown in Table 3-35 are higher than total credits for the months of January through September, 2009 due to credits to units that were overstated in initial market settlements, and required manual refunds to the transmission owner. These make whole payments will be allocated as generator local charge credits.

12 The total charges shown in Table 3-36 do not equal the total balancing charges shown in Table 3-35 because the totals in Table 3-35 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-36 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while LOC, cancellation, and local charges are allocated on an RTO wide basis, based on demand, supply, and generator deviations.

Deviations

Table 3-37 Monthly balancing operating reserve deviations (MWh): January through September 2008 and 2009 (See 2008 SOM, Table 3-46)

	2008 (Jan-Sep) Deviations				2009 (Jan-Sep) Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	8,172,164	3,297,121	2,572,113	14,041,398	9,128,112	5,575,170	2,637,718	17,341,000
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,044,702	4,153,575	2,107,229	13,305,505
Mar	6,392,821	2,520,387	2,405,061	11,318,269	7,214,090	4,352,550	2,410,544	13,977,183
Apr	5,951,654	3,127,726	2,224,157	11,303,537	6,873,427	3,836,896	2,275,153	12,985,477
May	6,624,696	3,787,650	2,699,616	13,111,962	6,958,699	5,184,983	2,382,351	14,526,033
Jun	8,117,669	3,179,999	2,644,016	13,941,684	8,569,879	4,603,052	2,635,991	15,808,922
Jul	9,237,956	3,914,230	2,213,828	15,366,014	9,233,511	5,129,409	2,280,626	16,643,546
Aug	8,296,485	4,000,974	2,275,294	14,572,753	9,961,944	5,425,344	2,349,290	17,736,578
Sep	7,360,536	3,691,646	2,577,095	13,629,277	7,972,378	4,171,876	2,114,798	14,259,052
Total	41,987,065	18,959,174	15,091,472	76,037,711	72,956,743	42,432,853	21,193,699	136,583,296
Share of Annual Deviations	55.2%	24.9%	19.8%	100.0%	53.4%	31.1%	15.5%	100.0%

Table 3-38 Regional charges determinants (MWh): January through September 2009 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	504,137,618	20,197,925	524,335,544	72,956,743	42,432,853	21,193,699	136,583,296	660,918,840
East	278,168,510	10,073,712	288,242,222	44,817,337	23,209,690	11,485,907	79,512,935	367,755,157
West	225,969,108	10,124,213	236,093,321	27,929,588	19,159,306	9,707,792	56,796,686	292,890,007

Figure 3-7 Daily RTO reliability and deviation rates: January through September 2009 (New Figure)

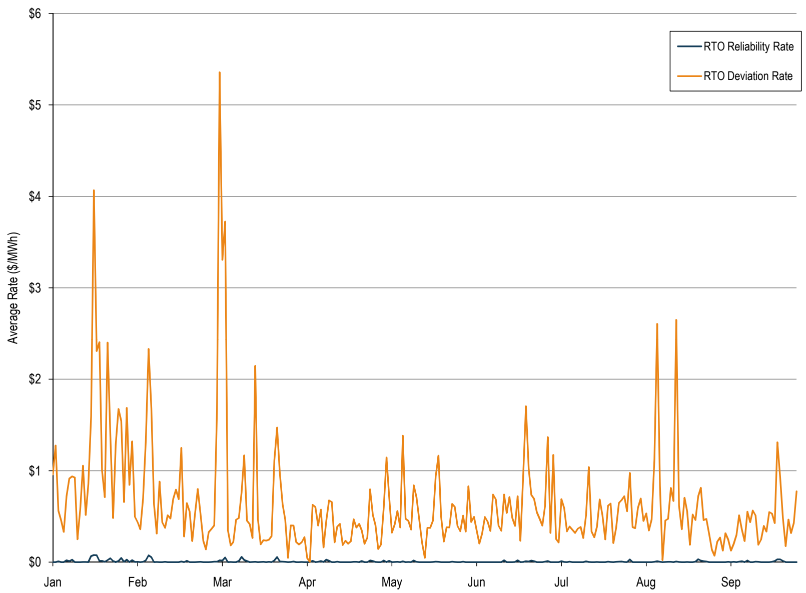
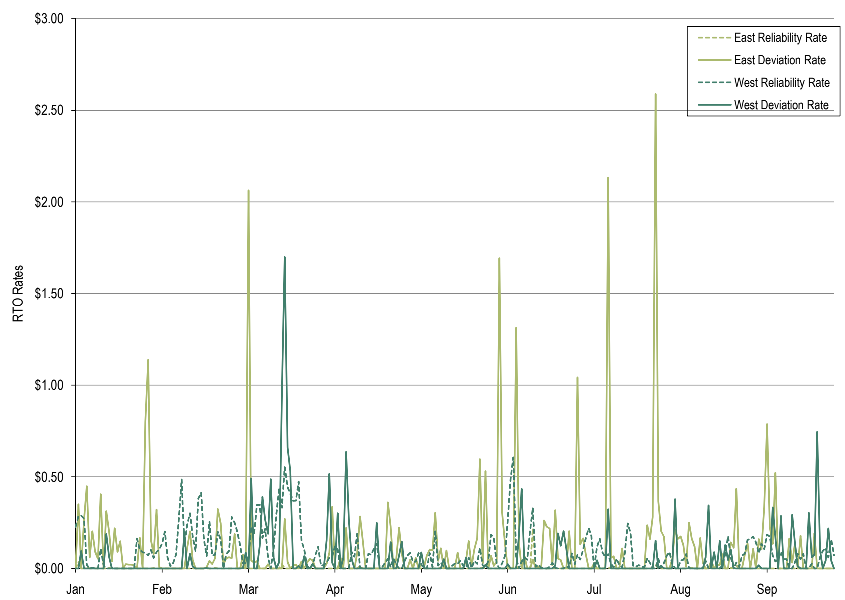


Figure 3-8 Daily regional reliability and deviation rates: January through September 2009 (New Figure)



Balancing Operating Reserve Charge Rate

Table 3-39 Average regional balancing operating reserve rates: January through September 2009 (See 2008 SOM, Table 3-48)

	Reliability	Deviations
RTO	0.006	0.648
East	0.001	0.122
West	0.087	0.057

Operating Reserve Credits by Category

Figure 3-9 Operating reserve credits: January through September 2009 (See 2008 SOM, Figure 3-11)

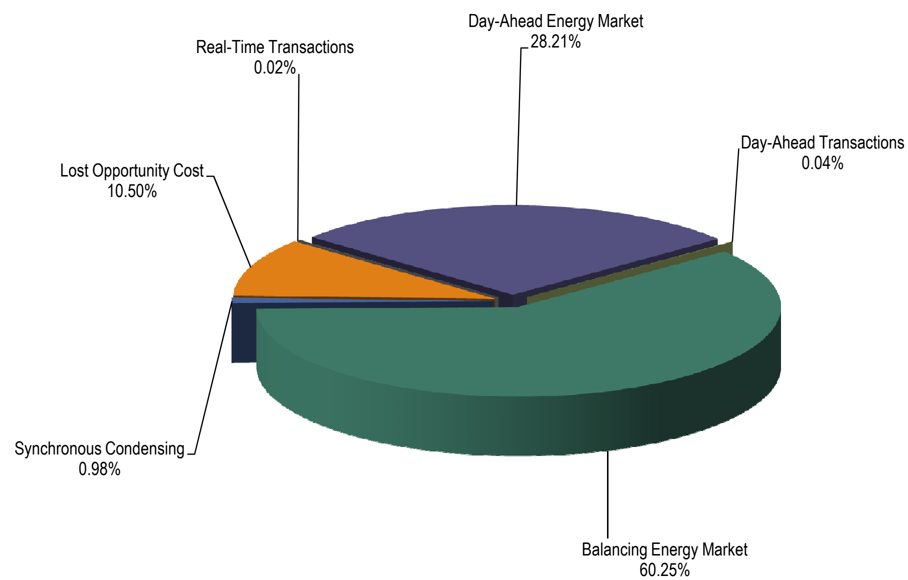


Table 3-40 Credits by month (By operating reserve market): January through September 2009 (See 2008 SOM, Table 3-49)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$9,260,150	$0	$1,328,814	$26,443,459	$0	$3,558,177	$40,590,600
Feb	$7,434,068	$0	$839,679	$14,413,879	$31,258	$2,062,873	$24,781,757
Mar	$9,542,383	$7,580	$108,664	$22,273,264	$13,249	$3,511,174	$35,456,315
Apr	$6,998,364	$0	$19,929	$10,746,431	$6,942	$1,833,546	$19,605,213
May	$6,024,108	$0	$5,543	$13,965,424	$0	$1,511,360	$21,506,435
Jun	$6,711,471	$10,858	$0	$16,058,244	$0	$2,527,907	$25,308,480
Jul	$8,183,242	$27,394	$38,643	$15,216,183	$0	$2,096,792	$25,562,254
Aug	$7,636,586	$60,588	$1	$15,210,565	$0	$5,368,663	$28,276,403
Sep	$6,057,599	$0	$13,611	$10,582,749	$0	$2,780,091	$19,434,049
Total	$67,847,971	$106,420	$2,354,884	$144,910,199	$51,449	$25,250,583	$240,521,506
Share of Credits	28.2%	0.0%	1.0%	60.2%	0.0%	10.5%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-41 Credits by unit types (By operating reserve market): January through September 2009 (See 2008 SOM, Table 3-50)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	40.1%	0.0%	59.1%	0.8%	$67,710,494
Combustion Turbine	1.6%	3.5%	72.4%	22.5%	$67,687,734
Diesel	0.1%	0.0%	4.0%	95.9%	$3,819,600
Hydro	0.0%	0.3%	99.7%	0.0%	$180,200
Nuclear	0.0%	0.0%	0.0%	100.0%	$150,645
Steam	39.3%	0.0%	55.1%	5.7%	$100,851,779
Wind Farm	0.0%	0.0%	58.4%	41.6%	$10,497

Table 3-42 Credits by operating reserve market (By unit type): January through September 2009 (See 2008 SOM, Table 3-51)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	40.0%	0.0%	27.6%	2.1%
Combustion Turbine	1.6%	100.0%	33.8%	60.2%
Diesel	0.0%	0.0%	0.1%	14.5%
Hydro	0.0%	0.0%	0.1%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.6%
Steam	58.4%	0.0%	38.3%	22.6%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$67,847,971	$2,354,884	$144,957,511	$25,250,583

Economic and Noneconomic Generation

Table 3-43 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: January through September 2009 (See 2008 SOM, Table 3-52)

	All Hours	On Peak	Off Peak
Self-scheduled generation	24.8%	23.3%	28.4%
Economic generation	63.6%	68.9%	50.7%
Noneconomic generation	10.1%	7.0%	17.7%
Regulation generation	1.5%	0.8%	3.2%
Total	100%	100%	100%

Table 3-44 PJM generation (By unit type receiving operating reserve payments): January through September 2009 (See 2008 SOM, Table 3-53)

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.0%	10.3%	24.4%	26.0%
Combustion turbine	0.3%	0.4%	2.1%	0.1%
Diesel	0.2%	0.0%	0.0%	0.0%
Hydroelectric	2.6%	0.6%	0.0%	0.0%
Steam	93.0%	88.7%	73.5%	74.0%
Wind	1.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

Table 3-45 PJM unit type generation distribution (By unit type receiving operating reserve payments): January through September 2009 (See 2008 SOM, Table 3-54)

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	7.3%	64.6%	24.3%	3.8%	100%
Combustion turbine	12.4%	46.0%	41.5%	0.1%	100%
Diesel	75.8%	17.5%	6.7%	0.0%	100%
Hydroelectric	63.7%	36.3%	0.0%	0.0%	100%
Steam	26.1%	64.1%	8.5%	1.3%	100%
Wind	99.2%	0.8%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-46 Monthly balancing operating reserve charges and credits to generators (By location): January through September 2009 (See 2008 SOM, Table 3-55)

	Eastern Region						Western Region							
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Deviation Credits Percent of Total Operating Reserve Credits
Jan	$2,038,901	$302,581	$2,341,482	$21,038,966	$2,617,930	$23,656,896	$1,655,607	$276,275	$1,931,882	$5,404,493	$940,247	$6,344,741	10.5%	66.6%
Feb	$799,666	$162,819	$962,486	$7,821,619	$1,685,163	$9,506,782	$726,523	$168,720	$895,243	$6,592,259	$377,710	$6,969,970	7.5%	59.5%
Mar	$1,493,041	$339,407	$1,832,448	$13,177,635	$2,283,617	$15,461,251	$1,359,326	$283,325	$1,642,651	$9,095,630	$1,227,558	$10,323,188	9.8%	64.6%
Apr	$505,788	$160,034	$665,822	$3,987,806	$1,098,113	$5,085,919	$530,487	$161,839	$692,326	$6,758,625	$735,433	$7,494,058	6.7%	56.5%
May	$701,590	$115,219	$816,808	$6,817,008	$1,311,304	$8,128,312	$700,361	$131,955	$832,316	$7,154,625	$200,056	$7,354,681	7.7%	66.1%
Jun	$1,040,688	$206,804	$1,247,492	$8,683,676	$2,014,143	$10,697,819	$920,214	$222,661	$1,142,875	$7,386,679	$513,764	$7,900,443	9.2%	65.2%
Jul	$947,502	$162,282	$1,109,784	$9,640,563	$1,855,776	$11,496,339	$617,861	$130,886	$748,748	$5,604,614	$241,016	$5,845,629	7.3%	60.8%
Aug	$1,095,199	$418,288	$1,513,487	$10,708,827	$4,839,160	$15,547,988	$838,707	$349,336	$1,188,044	$4,501,738	$529,502	$5,031,240	9.5%	56.5%
Sep	$592,176	$212,843	$805,019	$5,573,582	$2,594,659	$8,168,241	$549,716	$184,433	$734,149	$5,009,167	$185,432	$5,194,599	7.9%	56.5%
Average	52.8%	50.8%	52.4%	59.2%	73.4%	61.0%	47.2%	49.2%	47.6%	40.8%	26.6%	39.0%	8.6%	63.1%

Market Power Issues

Top 10 Units

Table 3-47 Top 10 units and organizations receiving total operating reserve credits: January through September 2009 (See 2008 SOM, Table 3-57)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$24,528,324	10.2%	10.2%	$70,296,769	29.2%	29.2%
2	$17,238,165	7.2%	17.4%	$48,586,092	20.2%	49.4%
3	$10,021,474	4.2%	21.5%	$24,600,093	10.2%	59.7%
4	$8,495,009	3.5%	25.1%	$15,209,491	6.3%	66.0%
5	$6,847,966	2.8%	27.9%	$13,079,299	5.4%	71.4%
6	$5,983,837	2.5%	30.4%	$10,049,183	4.2%	75.6%
7	$3,423,767	1.4%	31.8%	$8,715,685	3.6%	79.3%
8	$3,362,806	1.4%	33.2%	$5,556,467	2.3%	81.6%
9	$3,360,659	1.4%	34.6%	$4,086,988	1.7%	83.3%
10	$2,855,522	1.2%	35.8%	$3,729,968	1.6%	84.8%

Table 3-48 Top 10 units and organizations receiving day-ahead generator credits: January through September 2009 (See 2008 SOM, Table 3-58)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$12,814,488	18.9%	18.9%	$31,542,915	46.5%	46.5%
2	$8,629,554	12.7%	31.6%	$7,800,491	11.5%	58.0%
3	$8,168,880	12.0%	43.6%	$6,372,426	9.4%	67.4%
4	$2,485,187	3.7%	47.3%	$3,940,777	5.8%	73.2%
5	$1,417,222	2.1%	49.4%	$2,662,573	3.9%	77.1%
6	$1,381,387	2.0%	51.4%	$2,267,207	3.3%	80.5%
7	$1,235,554	1.8%	53.3%	$2,010,611	3.0%	83.4%
8	$1,070,665	1.6%	54.8%	$1,861,146	2.7%	86.2%
9	$722,248	1.1%	55.9%	$1,653,297	2.4%	88.6%
10	$668,548	1.0%	56.9%	$1,622,710	2.4%	91.0%

Table 3-49 Top 10 units and organizations receiving synchronous condensing credits: January through September 2009 (See 2008 SOM, Table 3-59)

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$199,676	8.5%	8.5%	$2,094,463	88.9%	88.9%
2	$199,001	8.5%	16.9%	$174,494	7.4%	96.4%
3	$192,296	8.2%	25.1%	$75,847	3.2%	99.6%
4	$191,155	8.1%	33.2%	$5,133	0.2%	99.8%
5	$188,686	8.0%	41.2%			
6	$187,366	8.0%	49.2%			
7	$183,946	7.8%	57.0%			
8	$89,051	3.8%	60.8%			
9	$86,246	3.7%	64.4%			
10	$77,903	3.3%	67.7%			

Table 3-50 Top 10 units and organizations receiving balancing generator credits: January through September 2009 (See 2008 SOM, Table 3-60)

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$15,896,419	11.0%	11.0%	$39,669,400	27.4%	27.4%
2	$8,148,763	5.6%	16.6%	$36,462,047	25.2%	52.5%
3	$6,277,324	4.3%	20.9%	$15,592,123	10.8%	63.3%
4	$5,570,753	3.8%	24.8%	$13,002,646	9.0%	72.2%
5	$4,314,924	3.0%	27.7%	$6,448,995	4.4%	76.7%
6	$3,080,612	2.1%	29.9%	$4,774,820	3.3%	80.0%
7	$3,019,261	2.1%	31.9%	$3,616,669	2.5%	82.5%
8	$2,450,815	1.7%	33.6%	$2,579,346	1.8%	84.3%
9	$2,187,103	1.5%	35.1%	$2,354,713	1.6%	85.9%
10	$2,087,549	1.4%	36.6%	$1,948,344	1.3%	87.2%

Table 3-51 Top 10 units and organizations receiving lost opportunity cost credits: January through September 2009 (See 2008 SOM, Table 3-61)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$1,609,528	6.4%	6.4%	$10,044,590	39.8%	39.8%
2	$1,430,884	5.7%	12.0%	$6,344,879	25.1%	64.9%
3	$1,397,091	5.5%	17.6%	$1,252,960	5.0%	69.9%
4	$1,308,823	5.2%	22.8%	$1,116,201	4.4%	74.3%
5	$1,292,277	5.1%	27.9%	$1,060,867	4.2%	78.5%
6	$1,257,205	5.0%	32.9%	$1,047,433	4.1%	82.6%
7	$1,047,433	4.1%	37.0%	$909,480	3.6%	86.2%
8	$909,480	3.6%	40.6%	$493,238	2.0%	88.2%
9	$843,495	3.3%	43.9%	$462,045	1.8%	90.0%
10	$680,646	2.7%	46.6%	$317,087	1.3%	91.3%

Figure 3-10 Cumulative distribution of units receiving credits (By operating reserve category): January through September 2009 (See 2008 SOM, Figure 3-12)

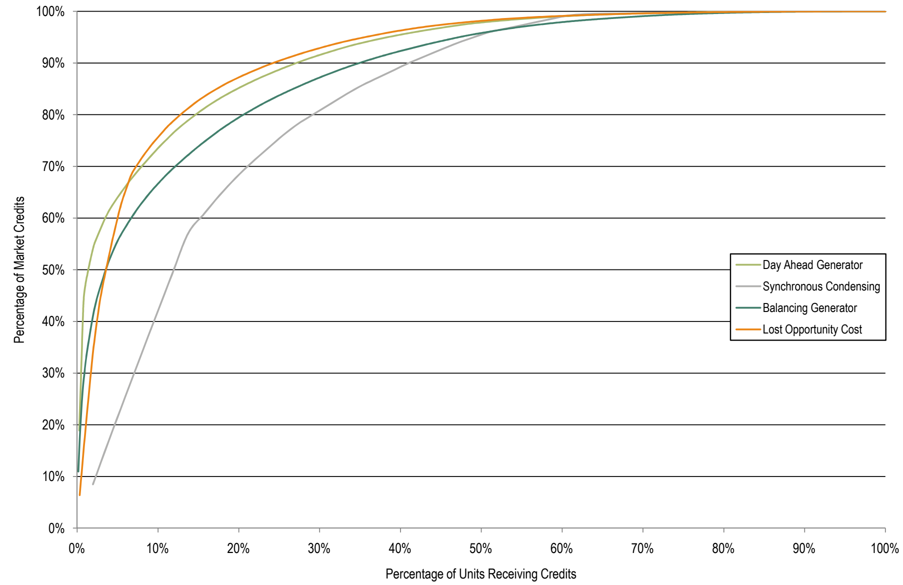
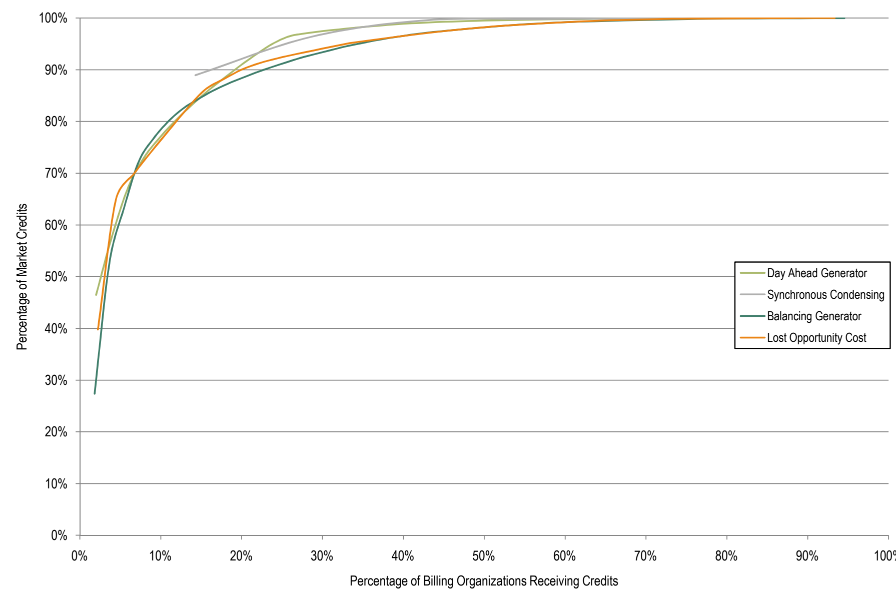


Figure 3-11 Cumulative distribution of billing organizations receiving credits (By operating reserve market): January through September 2009 (See 2008 SOM, Figure 3-13)



Markup

Unit Markup - Top 10 Units

Table 3-52 Top 10 operating reserve revenue units markup: January through September 2009 (See 2008 SOM, Table 3-62)

	Top 10 Units Weighted Markup	Steam Share of Top 10 Units Credits	Steam Units in Top 10 Weighted Markup	Combined Cycle Share of Top 10 Units Credits	Combined Cycle Units in Top 10 Weighted Markup	Combustion Turbine Share of Top 10 Units Credits	Combustion Turbine Units in Top 10 Weighted Markup
2009 (Jan -Sep)	(1.2%)	47.6%	(9.4%)	52.4%	3.5%	0.0%	NA

Unit Markup - All Units

Table 3-53 Average real-time weighted markup by unit type receiving balancing credits: January through September 2009 (New Table)

Unit Type	Number of Units	Weighted Markup
Combustion Turbine	391	(17.0%)
Steam	241	(7.8%)
Combined Cycle	48	(8.8%)
Diesel	21	(63.8%)
Hydro	11	259.2%
Nuclear	2	(30.0%)
Wind Farm	2	0.0%

Review of Impact on Regional Balancing Operating Reserve Charges

Total regional balancing generator credits for both reliability and deviation purposes for January through September 2009 totaled $130,210,454.

Table 3-54 Regional balancing operating reserve credits: January through September 2009 (New Table)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$3,567,076	$93,043,094	$96,610,170
East	$407,492	$10,452,090	$10,859,583
West	$19,458,945	$3,281,757	$22,740,702
Total	$23,433,513	$106,776,941	$130,210,454

Table 3-55 Total deviations: January through September 2009 (New Table)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	72,956,743	42,432,853	21,193,699	136,583,296

Under the old operating reserve construct, total credits for the day would have been allocated to demand, supply, and generator deviations at the rate of credits/deviations. This balancing rate would then have been applied against each organizations demand, supply, and generator deviations in the form of charges.

Table 3-56 Charge allocation under old operating reserve construct: January through September 2009 (New Table)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	72,956,743	42,432,853	21,193,699	136,583,296
Balancing Rate ($/MWh)	0.953	0.953	0.953	0.953
Charges ($)	$69,552,654	$40,452,978	$20,204,822	$130,210,454

Under the new operating reserve construct, rates are applied separately to credits for reliability or deviation purposes in the Eastern, Western, and RTO regions, resulting in six balancing rates. Reliability credits are allocated by Real-Time load MWh plus Real-Time export MWh in the Eastern and Western regions, and the sum of those MWh for the RTO rate. Regional deviation credits are allocated to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at aggregates that span both regions apply to RTO deviations). Total RTO deviations are the sum of the Eastern deviations, Western deviations, and the deviations that were directly applied to the RTO.

For January through September 2009, charges were actually allocated as shown in Table 3-57.

The difference between the charges based on the old operating reserve construct (see Table 3-56) and the actual charges allocated under the current rules is shown in Table 3-58, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

A breakdown of the reallocation of charges for the period January through September 2009 is shown in Table 3-59.

Table 3-57 Actual regional credits, charges, rates and charge allocation MWh: January through September 2009 (New Table)

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$3,567,076	524,335,544	0.007	$3,567,076	$93,043,094	136,583,296	0.681	$93,043,094	$96,610,170
East	$407,492	288,242,222	0.001	$407,492	$10,452,090	79,512,935	0.131	$10,452,090	$10,859,583
West	$19,458,945	236,093,321	0.082	$19,458,945	$3,281,757	56,796,686	0.058	$3,281,757	$22,740,702
Total	$23,433,513	524,335,544	NA	$23,433,513	$106,776,941	136,583,296	NA	$106,776,941	$130,210,454

Table 3-58 Difference in total charges between old rules and new rules: January through September 2009 (New Table)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$69,552,654	$40,452,978	$20,204,822	$130,210,454
Charges (Current)	$22,455,001	$978,512	$23,433,513	$56,820,347	$33,032,173	$16,924,422	$106,776,941
Difference	$22,455,001	$978,512	$23,433,513	($12,732,306)	($7,420,806)	($3,280,401)	($23,433,513)

Table 3-59 Difference in total charges between old rules and new rules: January through September 2009 (New Table)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Difference	$22,455,001	$978,512	$23,433,513	($12,732,306)	($7,420,806)	($3,280,401)	($23,433,513)