SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for the first nine months of 2010. 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 quantifies the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, 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 and in existing generation to serve PJM markets. Net revenue quantifies the contribution to total fixed 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 total fixed costs of investing in new generating resources when there is a market based need, 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.

  In 2009, total net revenues were not adequate to cover total fixed costs for a new entrant combustion turbine (CT), combined cycle (CC) or coal plant (CP) in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues in a year with reduced energy market revenues.

  In the first nine months of 2010, total net revenues were higher compared to the same period in 2009. The increases in total net revenues by technology type are the result of increases in energy revenues, resulting from higher energy prices, and in most cases, increases in capacity revenues, resulting from capacity prices determined in prior RPM auctions. In general, energy revenues are a larger proportion of total net revenues for CPs and CCs while capacity revenues are a larger proportion of total net revenues for CTs.

  For the new entrant CT, all zones had higher total net revenue in the first nine months of 2010 compared to the same period in 2009. (See Table 3-8.) For the new entrant CT, all zones had higher energy net revenue. All zones but two, BGE and Pepco, had higher capacity revenues. The 2010/2011 Base Residual Auction (BRA) cleared with much less price separation by location than prior delivery years, and at a higher price for the RTO Locational Deliverability Area (LDA) than previous BRAs. As a result, zones that previously cleared in constrained LDAs saw slight increases or, in the case of SWMAAC, decreases, in capacity revenue for calendar year 2010, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity revenue. The BGE and Pepco zones, which previously cleared in the SWMAAC LDA for the 2009/2010 delivery year, had a lower clearing price associated with the unconstrained RTO LDA for the 2010/2011 delivery year. The decreases in capacity revenue were more than offset by increases in energy net revenue. The six zones that were part of the MAAC+APS LDA for the 2009/2010 BRA and which previously cleared in the EMAAC LDA had slightly higher capacity revenues. Of these six zones, DPL showed a larger increase as DPL South separated and cleared at a slightly higher price than the RTO LDA in the 2010/2011 BRA. The five zones that had cleared in the unconstrained RTO LDA for the 2009/2010 delivery year had significantly higher capacity revenues as a result of higher capacity prices for the 2010/2011 delivery year. The four zones that cleared in the MAAC+APS LDA and that had cleared with the unconstrained RTO LDA in the 2008/2009 BRA, had significantly higher capacity revenues associated with the constrained MAAC+APS LDA in the 2009/2010 delivery year, but slightly lower capacity revenues associated with the 2010/2011 delivery year, thus the rate of increase in capacity revenue will fall through calendar year 2010.

For the new entrant CC, all zones had higher total net revenue in the first nine months of 2010 compared to the same period in 2009. (See Table 3-10.) For the new entrant CC, all zones showed an increase in energy net revenue. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

For the new entrant coal plant (CP), all seventeen zones had higher total net revenue in the first nine months of 2010 compared to the same period in 2009. (See Table 3-12.) For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through September 30, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,732.1 MW on September 30, a decrease of 1,121.7 MW or 0.7 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of September 30, 2010, 41.0 percent was coal; 28.7 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, and 0.3 percent was wind.

- **Generation Fuel Mix.** During the first nine months of 2010, coal provided 49.9 percent, nuclear 34.3 percent, gas 11.4 percent, oil 0.5 percent, hydroelectric 2.0 percent, solid waste 0.8 percent and wind 1.0 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

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 the operating reserve charges that equal these credits, 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 the First Nine Months of 2010.** The level of operating reserve credits and corresponding charges increased in the first nine months of 2010 by 67.1 percent compared to the first nine months of 2009. The largest increase occurred in the third quarter of 2010, which was 116.7 percent higher than the third quarter 2009. The level of operating reserve credits in the first quarter of 2010 increased by only 9.0 percent compared to the first quarter of 2009.

  The increase in total operating reserve credits was comprised of a 6.6 percent, or $4,480,596, decrease in the amount of day-ahead credits, a 73.3 percent, or $1,725,912, decrease in synchronous condensing credits, and a 98.0 percent, or $169,638,134, increase in balancing credits. The increase in balancing credits can be attributed primarily to the large increase in demand in the summer of 2010. Balancing operating reserve credits in each month of the summer in 2010 were more than double the levels in the summer months of 2009. In particular, increased Eastern reliability credits accounted for much of the increase. Total operating reserve credits for the first nine months of 2010 were higher than for the full year of 2009 by $81,036,135.

- **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. The MMU calculated the impact of the new operating reserve rules in three areas.

  The rule changes allocated an increased proportion of balancing operating reserve credits to real-time load and exports. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, defined as real-time load and exports. This rule change had a significant impact in the first nine months of 2010. The new operating reserve rules resulted in an increase of $82,450,015 in charges assigned to real-time load and exports for the first nine months of 2010. These increases were matched by a decrease of $46,020,429 in charges to demand deviations, a decrease of $22,590,700 in charges to supply deviations, and a decrease of $13,838,886 in charges to generator deviations.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $26,689,574 less in operating reserve charges in the first nine months of 2010 as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports.

  The rule changes included the introduction of segmented make whole payments, which results in a calculation of operating reserve credits for periods shorter than the 24 hours used under the old rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $14,909,560, or 6.9 percent, higher for the first nine months of 2010 than they would have been under the old rules, and a total of $23,083,966 higher since December 2008. The most significant difference since the new rule went into effect was for July 2010, when the increase in payments due to the rule change was $4,801,974.

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 can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. 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 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. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up 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. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

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.

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. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The third quarter of 2010 showed a continuation of trends noted in the second quarter of 2010 when compared to the same time period in the prior year. In the third quarter of 2010, energy market revenues were generally higher for combustion turbines and combined cycles, both using natural gas, as energy market prices in the third quarter increased more than the average delivered price of natural gas in most zones. Energy market net revenues for the CP were substantially higher in all zones as a result of higher energy market prices in the third quarter compared to the same period in 2009.

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 tend to be low 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. All zones had more high demand days in the third quarter of 2010 compared to 2009 and all zones showed a higher frequency of hours of real-time LMP greater than $200. The average on peak LMP for PJM increased 61 percent in the third quarter of 2010 compared to the same period in 2009, while in RECO and in PSEG, average on peak LMP increased by 80 and 82 percent. The PJM average real-time LMP was greater than $200 for thirteen hours in the third quarter of 2010, compared to zero hours in the same period for 2009. In RECO and PSEG, Real-Time LMP was greater than $200 for 36 hours and 42 hours in the third quarter of 2010, compared to zero hours in both zones for the same period in 2009. As a result, the average increase in energy net revenue for a new entrant CT was 257 percent, and the RECO and PSEG zones show increases of 357 and 338 percent.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the Capacity Market provides a significant stream of revenue that contributes to the recovery of total costs for existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The Capacity Market is also a significant source of net revenue to cover the fixed costs of investing in new peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when there is a mismatch between the energy net revenues used as the offset in determining Capacity Market prices and actual energy net revenues, 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 load following and peaking gas-fired units set price. For the first nine months of 2010, particularly in the third quarter, CCs and CTs ran more often, which increased the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2010 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2010 (See 2009 SOM, Table 3-3)

	Delivery Year 2009/2010			Delivery Year 2010/2011			RPM Revenue 2010 (Jan - Dec) $/MW
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	
AECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL South	$178.57	$38,214	$67,103
JCPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PJM	NA	$154.47	$23,325	NA	$174.42	$37,327	$60,652

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-4)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$45,810	$50,153	9%
AEP	$29,349	$36,671	25%
AP	$40,241	$50,153	25%
BGE	$60,681	$57,100	(6%)
ComEd	$29,349	$36,671	25%
DAY	$29,349	$36,671	25%
DLCO	$29,349	$36,671	25%
Dominion	$29,349	$36,671	25%
DPL	$45,810	$50,675	11%
JCPL	$45,810	$50,153	9%
Met-Ed	$40,241	$50,153	25%
PECO	$45,810	$50,153	9%
PENELEC	$40,241	$50,153	25%
Pepco	$60,681	$57,100	(6%)
PPL	$40,241	$50,153	25%
PSEG	$45,810	$50,153	9%
RECO	$45,810	$50,153	9%
PJM	$38,259	$44,605	17%

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM[1] (Dollars per MBtu): January through September 2009 and 2010 (See 2009 SOM, Table 3-5)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Natural Gas	$4.43	$5.08	15%
Delivered Coal	$3.14	$2.74	(13%)

1 The average delivered fuel prices shown in Table 3-3 are included for illustrative purposes, and represent the simple average of several indices for various delivery points throughout the PJM footprint.

Table 3-4 Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[2]: Net revenue for January through September 2009 and 2010 (See 2009 SOM, Table 3-6)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$10,047	$43,619	334%
AEP	$3,142	$8,892	183%
AP	$11,985	$24,634	106%
BGE	$12,879	$54,012	319%
ComEd	$2,387	$8,380	251%
DAY	$2,893	$9,075	214%
DLCO	$3,919	$13,719	250%
Dominion	$12,580	$43,343	245%
DPL	$12,674	$42,258	233%
JCPL	$10,229	$37,989	271%
Met-Ed	$9,332	$40,109	330%
PECO	$8,902	$37,115	317%
PENELEC	$5,679	$16,404	189%
Pepco	$20,330	$55,160	171%
PPL	$8,336	$34,282	311%
PSEG	$8,604	$37,681	338%
RECO	$7,303	$33,384	357%
PJM	$8,895	$31,768	257%

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 2009 and 2010 (See 2009 SOM, Table 3-7)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$42,470	$91,595	116%
AEP	$22,459	$35,377	58%
AP	$46,639	$65,079	40%
BGE	$46,652	$106,577	128%
ComEd	$17,755	$30,535	72%
DAY	$22,421	$36,291	62%
DLCO	$22,172	$37,762	70%
Dominion	$46,667	$92,196	98%
DPL	$46,230	$92,016	99%
JCPL	$43,472	$85,526	97%
Met-Ed	$38,889	$86,006	121%
PECO	$39,121	$83,181	113%
PENELEC	$33,676	$50,629	50%
Pepco	$60,297	$110,451	83%
PPL	$36,642	$77,152	111%
PSEG	$41,012	$85,855	109%
RECO	$37,148	$77,871	110%
PJM	$37,866	$73,182	93%

2 The energy net revenues presented for "PJM" for the periods January through June 2009 and 2010 in this section represent the simple average of all zonal energy net revenues. Similarly, the total net revenues presented for "PJM" represent the simple average energy net revenue.

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 2009 and 2010 (See 2009 SOM, Table 3-8)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$70,368	$143,499	104%
AEP	$20,467	$81,501	298%
AP	$46,693	$110,639	137%
BGE	$37,648	$157,876	319%
ComEd	$38,003	$100,098	163%
DAY	$28,063	$69,265	147%
DLCO	$24,481	$64,155	162%
Dominion	$41,757	$130,382	212%
DPL	$34,678	$124,961	260%
JCPL	$62,202	$133,130	114%
Met-Ed	$50,390	$128,414	155%
PECO	$63,780	$132,550	108%
PENELEC	$63,978	$88,447	38%
Pepco	$59,400	$146,130	146%
PPL	$59,672	$123,262	107%
PSEG	$82,573	$138,054	67%
RECO	$59,622	$127,010	113%
PJM	$49,634	$117,610	137%

New Entrant Combustion Turbine

Table 3-7 Real-time PJM average net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 (See 2009 SOM, Table 3-9)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Energy	$8,895	$31,768	257%
Capacity	$34,096	$40,214	18%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,799	$1,799	0%
Total	$44,789	$73,781	65%

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 2009 and 2010 (See 2009 SOM, Table 3-10)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$52,670	$90,633	72%
AEP	$31,095	$43,752	41%
AP	$49,645	$71,647	44%
BGE	$68,755	$107,289	56%
ComEd	$30,340	$43,240	43%
DAY	$30,846	$43,935	42%
DLCO	$31,872	$48,579	52%
Dominion	$40,533	$78,203	93%
DPL	$55,297	$89,742	62%
JCPL	$52,852	$85,003	61%
Met-Ed	$46,992	$87,123	85%
PECO	$51,525	$84,129	63%
PENELEC	$43,339	$63,418	46%
Pepco	$76,206	$108,437	42%
PPL	$45,996	$81,295	77%
PSEG	$51,227	$84,695	65%
RECO	$49,926	$80,398	61%
PJM	$44,789	$73,781	65%

New Entrant Combined Cycle

Table 3-9 Real-time PJM average net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 (See 2009 SOM, Table 3-11)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Energy	$37,866	$73,182	93%
Capacity	$36,961	$42,906	16%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$2,399	$2,399	0%
Total	$77,226	$118,487	53%

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 2009 and 2010 (See 2009 SOM, Table 3-12)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$89,124	$142,236	60%
AEP	$53,211	$73,050	37%
AP	$87,914	$115,720	32%
BGE	$107,673	$163,901	52%
ComEd	$48,506	$68,208	41%
DAY	$53,172	$73,964	39%
DLCO	$52,924	$75,436	43%
Dominion	$77,418	$129,869	68%
DPL	$92,884	$143,159	54%
JCPL	$90,126	$136,167	51%
Met-Ed	$80,163	$136,647	70%
PECO	$85,775	$133,822	56%
PENELEC	$74,950	$101,270	35%
Pepco	$121,317	$167,775	38%
PPL	$77,916	$127,793	64%
PSEG	$87,666	$136,496	56%
RECO	$83,802	$128,512	53%
PJM	$77,226	$118,487	53%

New Entrant Coal Plant

Table 3-11 Real-time PJM average net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 (See 2009 SOM, Table 3-13)

	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
Energy	$49,634	$117,610	137%
Capacity	$34,493	$40,452	17%
Synchronized	$0	$0	0%
Regulation	$204	$0	(100%)
Reactive	$1,337	$1,337	0%
Total	$85,668	$159,400	86%

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 2009 and 2010 (See 2009 SOM, Table 3-14)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$113,359	$190,550	68%
AEP	$48,497	$116,363	140%
AP	$84,577	$157,748	87%
BGE	$93,822	$211,232	125%
ComEd	$66,675	$135,076	103%
DAY	$56,483	$104,022	84%
DLCO	$52,548	$98,900	88%
Dominion	$69,711	$165,122	137%
DPL	$77,436	$172,408	123%
JCPL	$105,112	$180,159	71%
Met-Ed	$88,210	$175,406	99%
PECO	$106,716	$179,597	68%
PENELEC	$102,672	$135,434	32%
Pepco	$115,660	$199,420	72%
PPL	$97,567	$170,273	75%
PSEG	$126,080	$185,101	47%
RECO	$102,517	$174,045	70%
PJM	$85,668	$159,611	86%

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 2009 and 2010 (See 2009 SOM, Table 3-15)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$5,455	$28,044	414%
AEP	$875	$5,248	500%
AP	$4,529	$16,664	268%
BGE	$6,260	$36,429	482%
ComEd	$334	$5,232	1,465%
DAY	$496	$5,649	1,039%
DLCO	$894	$7,787	771%
Dominion	$6,231	$28,842	363%
DPL	$5,893	$26,786	355%
JCPL	$4,146	$25,086	505%
Met-Ed	$3,867	$26,229	578%
PECO	$4,150	$24,909	500%
PENELEC	$2,695	$12,031	346%
Pepco	$13,751	$40,735	196%
PPL	$3,634	$21,408	489%
PSEG	$3,357	$24,278	623%
RECO	$2,556	$22,245	770%
PJM	$4,066	$21,035	417%

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 2009 and 2010 (See 2009 SOM, Table 3-16)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$40,074	$80,094	100%
AEP	$17,190	$31,179	81%
AP	$38,367	$60,594	58%
BGE	$42,834	$95,595	123%
ComEd	$10,844	$25,707	137%
DAY	$15,470	$31,437	103%
DLCO	$14,990	$35,496	137%
Dominion	$43,095	$85,103	97%
DPL	$41,414	$80,507	94%
JCPL	$39,691	$78,601	98%
Met-Ed	$34,468	$76,302	121%
PECO	$36,469	$76,224	109%
PENELEC	$30,100	$51,544	71%
Pepco	$56,952	$104,736	84%
PPL	$32,838	$67,923	107%
PSEG	$37,348	$77,442	107%
RECO	$32,850	$71,938	119%
PJM	$33,235	$66,495	100%

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 2009 and 2010 (See 2009 SOM, Table 3-17)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	Percent Change
AECO	$72,861	$139,420	91%
AEP	$16,497	$79,880	384%
AP	$40,888	$109,447	168%
BGE	$37,183	$155,210	317%
ComEd	$34,132	$98,843	190%
DAY	$23,161	$66,433	187%
DLCO	$18,006	$63,561	253%
Dominion	$40,187	$130,450	225%
DPL	$32,571	$120,643	270%
JCPL	$62,547	$133,242	113%
Met-Ed	$49,372	$125,874	155%
PECO	$66,233	$133,051	101%
PENELEC	$65,455	$93,398	43%
Pepco	$59,214	$146,901	148%
PPL	$60,302	$121,401	101%
PSEG	$85,230	$137,643	61%
RECO	$59,593	$130,588	119%
PJM	$48,437	$116,823	141%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through September 2010 (See 2009 SOM, Table 3-18)

	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	$5,113	$1,966	$3,148	62%
2010 (Jan - Sep)	$31,768	$21,035	$10,733	34%

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 year 2000 to 2009 and January through September 2010 (See 2009 SOM, Table 3-19)

	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	$31,581	$28,360	$3,221	10%
2010 (Jan - Sep)	$73,182	$66,495	$6,687	9%

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 year 2000 to 2009 and January through September 2010 (See 2009 SOM, Table 3-20)

	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	$49,022	$45,844	$3,178	6%
2010 (Jan - Sep)	$117,610	$116,823	$787	1%

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2009 SOM, Table 3-21)

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705
CC	$93,549	$99,230	$143,600	$171,361	$173,174
CP	$208,247	$267,792	$359,750	$492,780	$446,550

New Entrant Combustion Turbine

Figure 3-1 New entrant CT zonal real-time 2010 net revenue by market for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (New Figure)

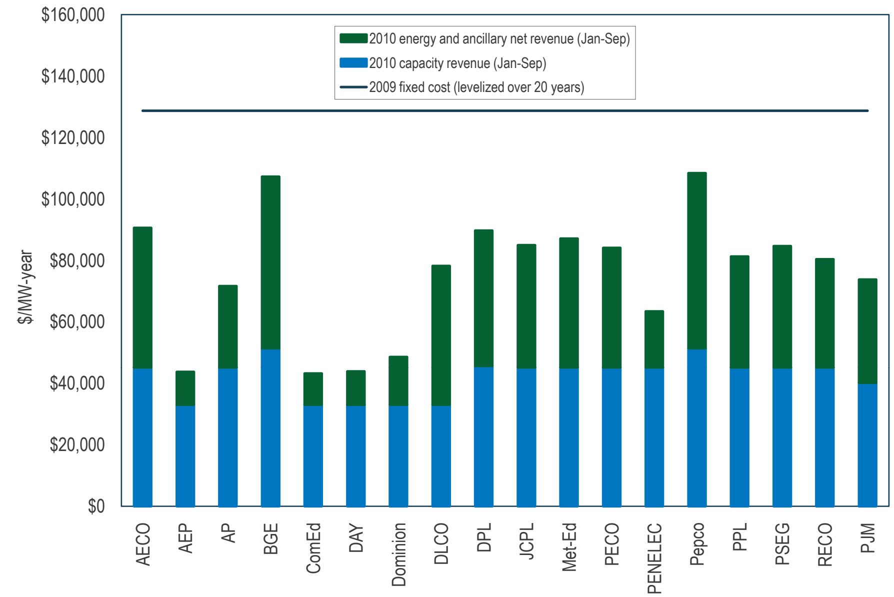
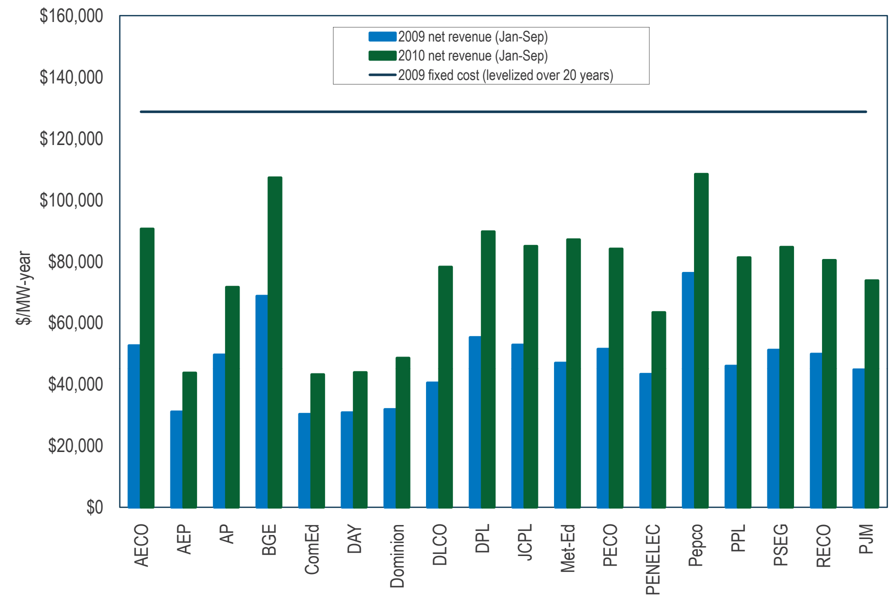


Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-23)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$52,670	$90,633	$128,705	41%	70%
AEP	$31,095	$43,752	$128,705	24%	34%
AP	$49,645	$71,647	$128,705	39%	56%
BGE	$68,755	$107,289	$128,705	53%	83%
ComEd	$30,340	$43,240	$128,705	24%	34%
DAY	$30,846	$43,935	$128,705	24%	34%
DLCO	$31,872	$48,579	$128,705	25%	38%
Dominion	$40,533	$78,203	$128,705	31%	61%
DPL	$55,297	$89,742	$128,705	43%	70%
JCPL	$52,852	$85,003	$128,705	41%	66%
Met-Ed	$46,992	$87,123	$128,705	37%	68%
PECO	$51,525	$84,129	$128,705	40%	65%
PENELEC	$43,339	$63,418	$128,705	34%	49%
Pepco	$76,206	$108,437	$128,705	59%	84%
PPL	$45,996	$81,295	$128,705	36%	63%
PSEG	$51,227	$84,695	$128,705	40%	66%
RECO	$49,926	$80,398	$128,705	39%	62%
PJM	$44,789	$73,781	$128,705	35%	57%

Figure 3-2 New entrant CT real-time 2009 and 2010 net revenue for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-3)



New Entrant Combined Cycle

Figure 3-3 New entrant CC zonal real-time 2010 net revenue by market for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (New Figure)

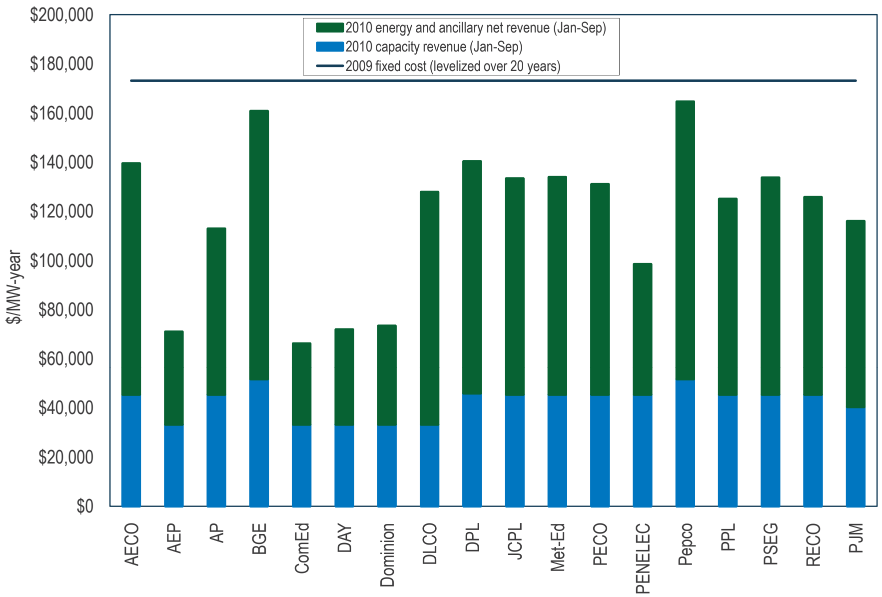
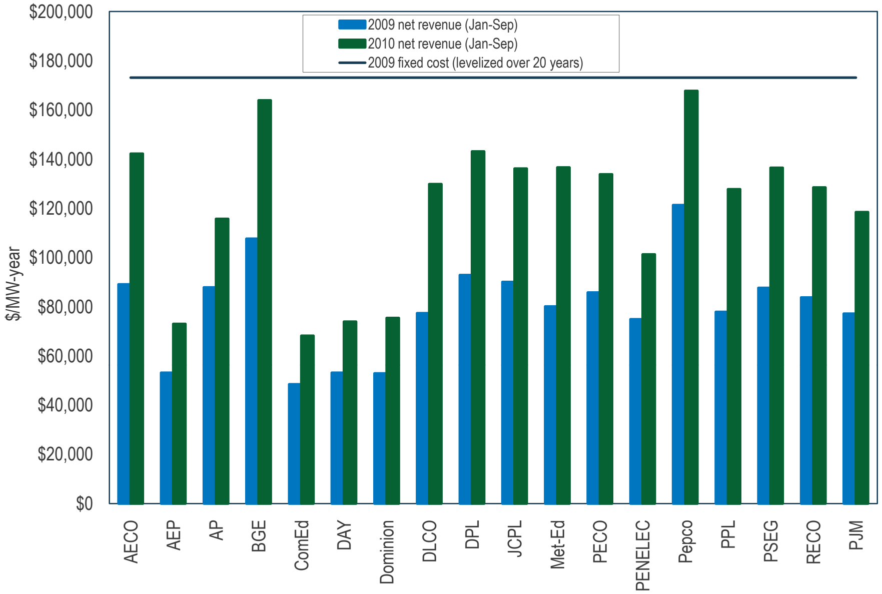


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-25)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$89,124	$142,236	$173,174	51%	82%
AEP	$53,211	$73,050	$173,174	31%	42%
AP	$87,914	$115,720	$173,174	51%	67%
BGE	$107,673	$163,901	$173,174	62%	95%
ComEd	$48,506	$68,208	$173,174	28%	39%
DAY	$53,172	$73,964	$173,174	31%	43%
DLCO	$52,924	$75,436	$173,174	31%	44%
Dominion	$77,418	$129,869	$173,174	45%	75%
DPL	$92,884	$143,159	$173,174	54%	83%
JCPL	$90,126	$136,167	$173,174	52%	79%
Met-Ed	$80,163	$136,647	$173,174	46%	79%
PECO	$85,775	$133,822	$173,174	50%	77%
PENELEC	$74,950	$101,270	$173,174	43%	58%
Pepco	$121,317	$167,775	$173,174	70%	97%
PPL	$77,916	$127,793	$173,174	45%	74%
PSEG	$87,666	$136,496	$173,174	51%	79%
RECO	$83,802	$128,512	$173,174	48%	74%
PJM	$77,226	$118,487	$173,174	45%	68%

Figure 3-4 New entrant CC real-time 2009 and 2010 net revenue for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-5)



New Entrant Coal Plant

Figure 3-5 New entrant CP zonal real-time 2010 net revenue by market for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (New Figure)

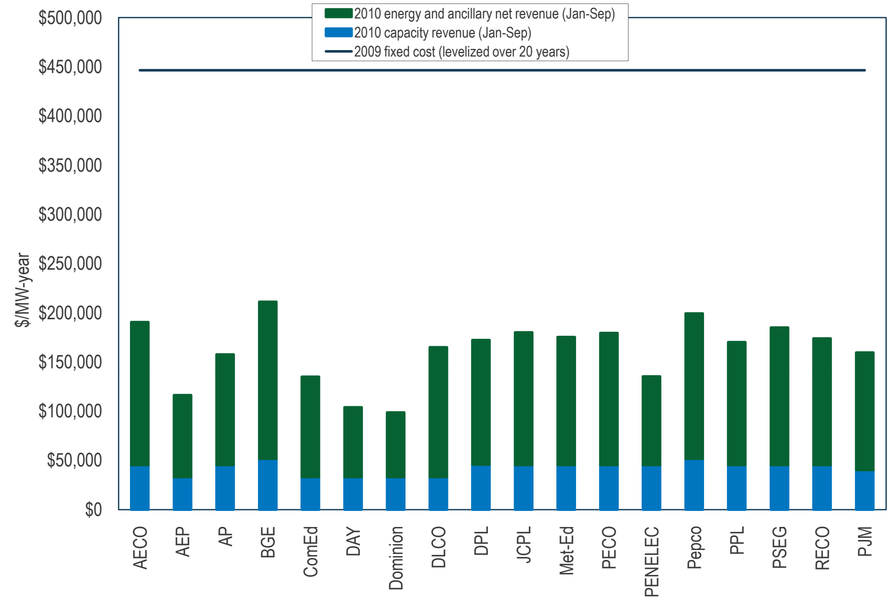
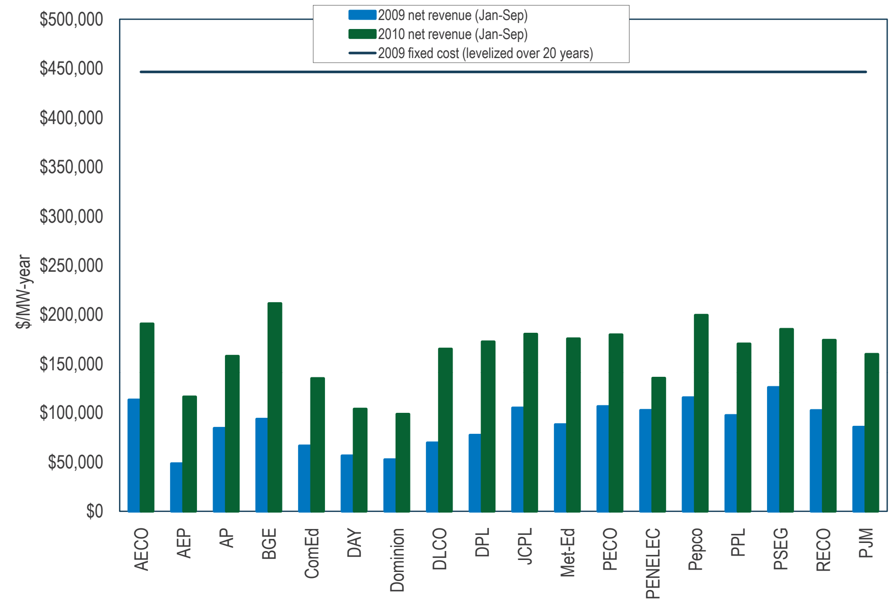


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2009 and 2010 (See 2009 SOM, Table 3-27)

Zone	2009 (Jan - Sep)	2010 (Jan - Sep)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$113,359	$190,550	$446,550	25%	43%
AEP	$48,497	$116,363	$446,550	11%	26%
AP	$84,577	$157,748	$446,550	19%	35%
BGE	$93,822	$211,232	$446,550	21%	47%
ComEd	$66,675	$135,076	$446,550	15%	30%
DAY	$56,483	$104,022	$446,550	13%	23%
DLCO	$52,548	$98,900	$446,550	12%	22%
Dominion	$69,711	$165,122	$446,550	16%	37%
DPL	$77,436	$172,408	$446,550	17%	39%
JCPL	$105,112	$180,159	$446,550	24%	40%
Met-Ed	$88,210	$175,406	$446,550	20%	39%
PECO	$106,716	$179,597	$446,550	24%	40%
PENELEC	$102,672	$135,434	$446,550	23%	30%
Pepco	$115,660	$199,420	$446,550	26%	45%
PPL	$97,567	$170,273	$446,550	22%	38%
PSEG	$126,080	$185,101	$446,550	28%	41%
RECO	$102,517	$174,045	$446,550	23%	39%
PJM	$85,668	$159,611	$446,550	19%	36%

Figure 3-6 New entrant CP real-time 2009 and 2010 net revenue for January through September and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-7)



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, and September 30, 2010 (See 2009 SOM, Table 3-35)

	1-Jan-10		31-May-10		1-Jun-10		30-Sep-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,155.5	40.7%	67,991.1	40.8%	68,347.0	41.0%
Gas	49,238.8	29.3%	48,991.4	29.3%	48,424.5	29.0%	47,924.2	28.7%
Hydroelectric	7,921.9	4.7%	7,923.5	4.7%	7,923.5	4.8%	7,923.5	4.8%
Nuclear	30,611.9	18.2%	30,599.3	18.3%	30,619.0	18.4%	30,604.0	18.4%
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,741.6	6.4%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	680.1	0.4%
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	511.7	0.3%
Total	167,853.8	100.0%	167,400.7	100.0%	166,756.8	100.0%	166,732.1	100.0%

Energy Production by Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through September 2010[3] (See 2009 SOM, Table 3-36)

	GWh	Percent
Coal	279,394.7	49.9%
Nuclear	192,379.3	34.3%
Gas	64,024.4	11.4%
Natural Gas	62,810.2	11.2%
Landfill Gas	1,213.9	0.2%
Biomass Gas	0.4	0.0%
Hydroelectric	11,192.6	2.0%
Wind	5,599.2	1.0%
Waste	4,684.4	0.8%
Solid Waste	3,563.2	0.6%
Miscellaneous	1,121.2	0.2%
Oil	2,942.6	0.5%
Heavy Oil	2,506.1	0.4%
Light Oil	395.8	0.1%
Diesel	28.0	0.0%
Kerosene	12.7	0.0%
Jet Oil	0.1	0.0%
Solar	3.7	0.0%
Battery	0.3	0.0%
Total	560,221.2	100.0%

3 Hydroelectric generation does not net out the MWh used at pumped storage facilities to pump water.

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through September 2010[4] (See 2009 SOM, Table 3-37)

	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	2,516
2010	1,169

PJM Generation Queues

Table 3-26 Queue comparison (MW): September 30, 2010 vs. December 31, 2009 (See 2009 SOM, Table 3-38)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	14,067	(8,667)	(62%)
2011	15,873	17,235	1,362	8%
2012	11,053	12,599	1,545	12%
2013	6,350	8,664	2,314	27%
2014	13,439	13,437	(2)	(0%)
2015	3,091	2,958	(133)	(4%)
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	75,144	(1,581)	(2%)

4 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-27 Capacity in PJM queues (MW): At September 30, 2010[5, 6] (See 2009 SOM, Table 3-39)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
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	505	0	3,978	4,482
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,978	1,348	144	4,104	7,574
P Expired 31-Jan-06	853	1,008	1,922	4,918	8,701
Q Expired 31-Jul-06	1,772	707	3,685	8,450	14,614
R Expired 31-Jan-07	5,511	648	708	15,974	22,840
S Expired 31-Jul-07	7,009	1,430	1,277	11,178	20,893
T Expired 31-Jan-08	12,636	397	299	14,235	27,566
U Expired 31-Jan-09	9,679	121	853	20,781	31,434
V Expired 31-Jan-10	13,330	55	104	3,218	16,707
W Expires 31-Jan-11	10,970	0	15	3	10,987
Total	65,134	24,979	10,010	199,885	300,008

5 The *2010 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.

Table 3-28 Average project queue times: At September 30, 2010 (See 2009 SOM, Table 3-40)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	824	638	0	4,420
In-Service	740	621	0	3,287
Suspended	2,193	737	890	3,622
Under Construction	1,152	893	0	4,370
Withdrawn	519	522	0	3,186

Distribution of Units in the Queues

Table 3-29 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2010[7] (See 2009 SOM, Table 3-41)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	10	703	2	0	0	1,091	665	1,066	63	3,599
AEP	0	1,855	594	6	170	84	56	2,206	12,201	12	17,184
AP	32	958	2	13	108	0	428	724	1,388	0	3,653
BGE	0	0	0	30	0	1,640	0	132	0	0	1,802
ComEd	20	1,680	1,038	78	0	750	0	1,366	20,303	0	25,235
DAY	0	0	10	2	112	0	40	12	1,740	0	1,916
DLCO	0	0	0	0	0	91	0	0	0	0	91
Dominion	0	2,691	1,893	13	30	1,839	150	481	770	53	7,919
DPL	0	0	109	0	0	0	180	43	450	0	782
JCPL	0	1,080	27	33	0	0	465	0	0	0	1,605
Met-Ed	20	650	9	31	0	24	85	10	0	0	829
PECO	0	1,213	37	5	0	510	21	18	0	0	1,805
PENELEC	0	0	65	15	32	0	38	90	1,049	5	1,294
Pepco	0	2,025	230	0	0	0	0	0	0	0	2,255
PPL	20	0	139	10	143	1,600	104	33	179	0	2,228
PSEG	0	1,940	767	10	0	0	186	45	0	0	2,948
Total	92	14,101	5,622	248	594	6,538	2,844	5,824	39,147	133	75,144

7 In this section, unit type "Unknown" is referred to for units that the RTEP has not yet identified.

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2010[8] (See 2009 SOM, Table 3-42)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	0	4,243	1,643	51	0	510	1,943	771	1,516	63	10,739
SWMAAC	0	2,025	230	30	0	1,640	0	132	0	0	4,057
WMAAC	40	650	213	56	175	1,624	228	133	1,228	5	4,350
RTO	52	7,184	3,537	111	420	2,764	674	4,789	36,402	66	55,998
Total	92	14,101	5,622	248	594	6,538	2,844	5,824	39,147	133	75,144

Table 3-31 Existing PJM capacity: At September 30, 2010[9] (By zone and unit type (MW)) (See 2009 SOM, Table 3-43)

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	608	23	0	0	1,264	0	8	1,902
AEP	0	4,355	3,668	57	1,005	2,106	21,568	0	955	33,713
AP	0	1,129	1,178	36	108	0	7,963	0	431	10,845
BGE	0	0	849	7	0	1,705	3,026	0	0	5,587
ComEd	0	1,814	7,110	111	0	10,376	7,090	0	1,903	28,403
DAY	0	0	1,358	52	0	0	3,572	3	0	4,985
DLCO	0	101	188	0	6	1,777	1,239	0	0	3,311
Dominion	0	3,173	3,853	164	3,558	3,494	8,617	0	0	22,859
DPL	0	376	2,496	96	0	0	1,919	0	0	4,887
External	0	974	1,890	0	0	439	10,064	0	185	13,552
JCPL	0	1,192	1,423	25	400	615	318	0	0	3,972
Met-Ed	0	2,000	406	23	20	805	890	0	0	4,143
PECO	1	2,552	836	7	1,642	4,509	2,129	3	0	11,679
PENELEC	0	0	287	39	505	0	6,834	0	497	8,161
Pepco	0	0	1,555	12	0	0	4,706	0	0	6,273
PPL	0	956	1,362	63	571	2,375	5,532	0	217	11,075
PSEG	0	2,921	2,866	0	5	3,553	2,535	10	0	11,890
Total	1	21,542	31,932	714	7,820	31,753	89,264	16	4,194	187,236

8 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
9 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-32 PJM capacity age: At September 30, 2010 (MW) (See 2009 SOM, Table 3-44)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,307	18,925	377	10	0	2,089	16	4,194	42,918
10 to 20	0	3,976	4,740	129	49	0	6,148	0	0	15,042
20 to 30	0	158	490	38	3,438	16,186	9,997	0	0	30,307
30 to 40	0	101	5,276	39	435	14,953	31,657	0	0	52,461
40 to 50	0	0	2,501	128	2,480	615	24,346	0	0	30,069
50 to 60	0	0	0	4	348	0	13,523	0	0	13,875
60 to 70	0	0	0	0	32	0	1,356	0	0	1,388
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	27	0	0	0	0	27
Total	1	21,542	31,932	714	7,820	31,753	89,264	16	4,194	187,236

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[10] (See 2009 SOM, Table 3-45)

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%	0	1	0.0%
	Combined Cycle	0	0.0%	7,041	20.5%	4,243	11,284	28.7%
	Combustion Turbine	955	12.3%	8,230	24.0%	1,643	8,917	22.7%
	Diesel	49	0.6%	150	0.4%	51	151	0.4%
	Hydroelectric	2,042	26.2%	2,047	6.0%	0	2,047	5.2%
	Nuclear	615	7.9%	8,676	25.3%	510	8,572	21.8%
	Solar	0	0.0%	13	0.0%	1,943	1,956	5.0%
	Steam	4,135	53.0%	8,164	23.8%	771	4,800	12.2%
	Wind	0	0.0%	8	0.0%	1,516	1,524	3.9%
	Unknown	0	0.0%	0	0.0%	63	63	3.0%
	EMAAC Total	7,796	100.0%	34,330	100.0%	10,739	39,315	100.0%
SWMAAC	Combined Cycle	0	0.0%	0	0.0%	2,025	2,025	16.7%
	Combustion Turbine	540	14.2%	2,404	20.3%	230	2,093	17.3%
	Diesel	0	0.0%	19	0.2%	30	49	0.4%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	27.6%

10 Percents shown in Table 3-33 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
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	38.0%
	SWMAAC Total	3,807	100.0%	11,859	100.0%	4,057	12,109	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	40	40	0.2%
	Combined Cycle	0	0.0%	2,956	12.6%	650	3,606	16.9%
	Combustion Turbine	296	4.3%	2,054	8.8%	213	1,971	9.2%
	Diesel	35	0.5%	125	0.5%	56	145	0.7%
	Hydroelectric	444	6.5%	1,096	4.7%	175	1,270	6.0%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	22.5%
	Solar	0	0.0%	0	0.0%	228	228	1.1%
	Steam	6,042	88.6%	13,256	56.7%	133	7,346	34.5%
	Wind	0	0.0%	713	3.1%	1,228	1,942	9.1%
	Unknown	0	0.0%	0	0.0%	5	5	0.0%
	WMAAC Total	6,817	100.0%	23,379	100.0%	4,350	21,316	100.0%
RTO	Battery	0	0.0%	0	0.0%	52	52	0.0%
	Combined Cycle	0	0.0%	11,545	9.8%	7,184	18,729	12.9%
	Combustion Turbine	709	2.5%	19,244	16.4%	3,537	22,073	15.2%
	Diesel	48	0.2%	421	0.4%	111	484	0.3%
	Hydroelectric	1,401	5.0%	4,677	4.0%	420	3,696	2.5%
	Nuclear	0	0.0%	18,192	15.5%	2,764	20,956	14.4%
	Solar	0	0.0%	3	0.0%	674	676	0.5%
	Steam	25,931	92.3%	60,112	51.1%	4,789	38,969	26.8%
	Wind	0	0.0%	3,473	3.0%	36,402	39,876	27.4%
	Unknown	0	0.0%	0	0.0%	66	66	0.0%
	RTO Total	28,089	100.0%	117,667	100.0%	55,998	145,576	100.0%
All Areas	Total	46,509		187,236		75,144	218,317	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through September 2010 (See 2009 SOM, Table 3-46)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	19.4%	96,538	1,604
Capacity Resource	27.2%	189,394	2,590
All Units	25.2%	285,932	4,194

Table 3-35 Wind resources in real time offering at a negative price in PJM, January through September 2010 (See 2009 SOM, Table 3-47)

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	465.8	1,114	1.42%
All Wind	1,291.6	1,408	1.79%

Figure 3-7 Average hourly real-time generation of wind units in PJM, January through September 2010 (See 2009 SOM, Figure 3-11)

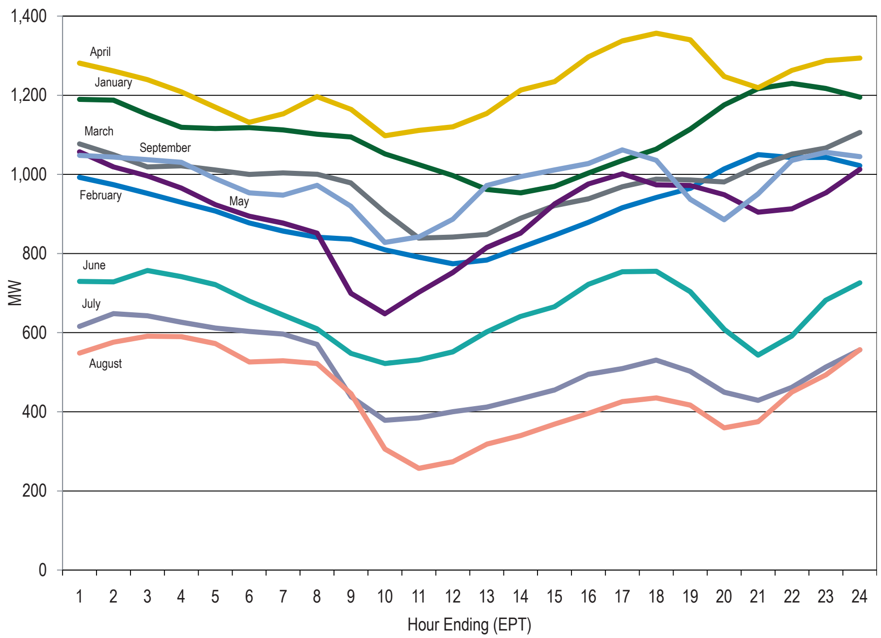


Figure 3-8 Average hourly day-ahead generation of wind units in PJM, January through September 2010 (See 2009 SOM, Figure 3-12)

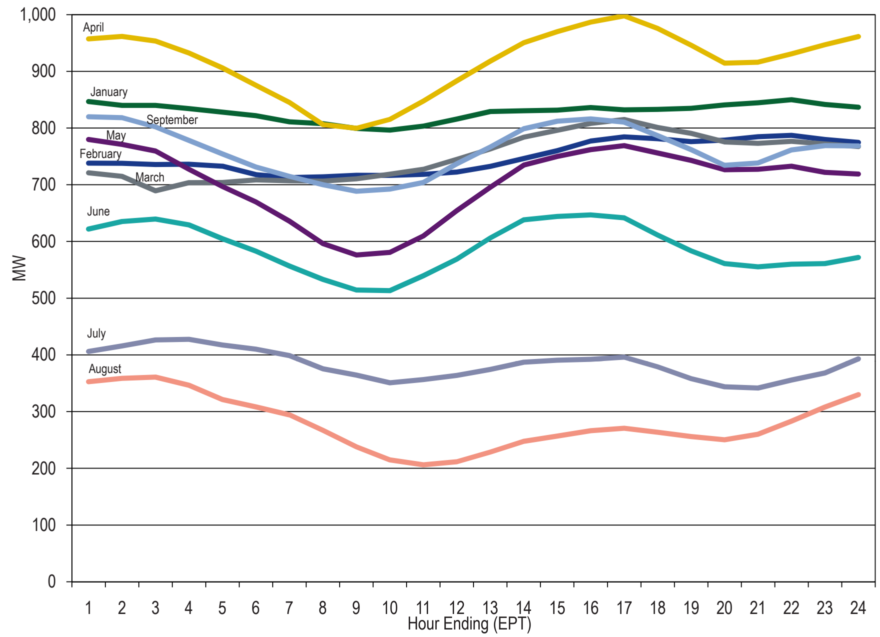


Table 3-36 Capacity factor of wind units in PJM by month, January through September 2010[11] (See 2009 SOM, Table 3-48)

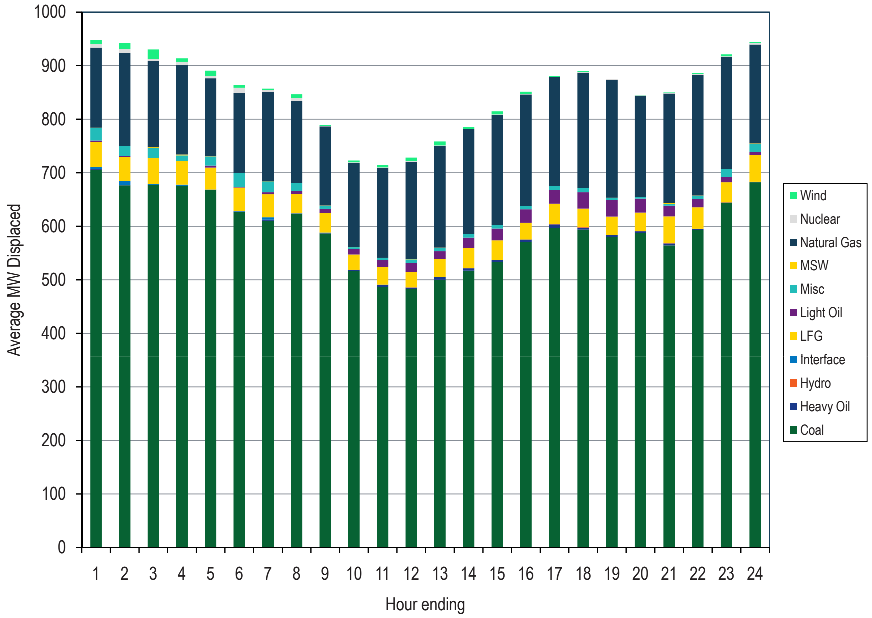
Month	Generation (MWh)	Capacity Factor
January	818,423.9	37.6%
February	612,044.4	29.3%
March	727,819.1	30.2%
April	881,317.4	36.3%
May	670,571.5	26.8%
June	472,775.6	19.0%
July	380,114.8	14.7%
August	330,818.7	12.4%
September	705,289.0	24.4%
October		
November		
December		
Annual	5,599,174.4	25.2%

11 Capacity factor shown in Table 3-36 is based on all hours in January through September, 2010.

Table 3-37 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, January through September 2010 (See 2009 SOM, Table 3-49)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	31.0%	35.3%	18.2%		24.0%
	Average Wind Generation	960.6	1,188.6	650.8		814.9
	Average Load	86,485.1	73,871.4	74,018.2		89,846.1
Off-Peak	Capacity Factor	33.5%	37.3%	20.6%		26.2%
	Average Wind Generation	1,033.9	1,257.9	736.7		889.5
	Average Load	75,824.0	59,326.6	95,159.1		73,066.0

Figure 3-9 Marginal fuel at time of wind generation in PJM, January through September 2010 (See 2009 SOM, Figure 3-13)



Operating Reserve

Credit and Charge Categories

Table 3-38 Operating reserve credits and charges (See 2009 SOM, Table 3-50)

For Credits Received	By Charges Paid
Day ahead:	Day-ahead demand
Day-Ahead Energy Market	Decrement bids
Day-ahead import transactions	Day-ahead export transactions
Synchronous condensing	Real-time load
	Real-time export transactions
Balancing:	
Balancing energy market	Real-time deviations
Lost opportunity cost	from day-ahead schedules
Real-time import transactions	
Balancing Energy Market Credits Received	**By Balancing Energy Market Charges Paid**
By (RTO, Eastern Region, Western Region)	Real-time load
Reliability Credits	Real-time export transactions
Deviation Credits	Real-time deviations
	from day-ahead schedules

Table 3-39 Operating reserve deviations (See 2009 SOM, Table 3-51)

Deviations		
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Balancing Credits and Charges

Table 3-40 Balancing operating reserve allocation process (See 2009 SOM, Table 3-52)

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Credit and Charge Results

Overall Results

Table 3-41 Monthly operating reserve charges: Calendar year 2009 and January through September 2010 (See 2009 SOM, Table 3-54)[12]

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,472,496	$50,803,869
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,346,529	$33,786,738
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,823,288	$25,782,991
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$7,633,141	$93,253	$22,870,495	$30,596,889
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$5,127,307	$131,600	$38,987,045	$44,245,952
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$3,511,264	$33,923	$56,903,524	$60,448,710
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255	$4,601,788	$88,136	$62,814,415	$67,504,339
Aug	$7,697,174	$1	$21,164,586	$28,861,761	$3,622,670	$66,535	$41,526,188	$45,215,393
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577	$8,433,892	$27,971	$40,031,736	$48,493,599
Oct	$7,046,301	$0	$17,026,425	$24,072,727				
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519				
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245				
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$63,473,794	$628,972	$342,775,715	$406,878,481
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	15.6%	0.2%	84.2%	100.0%

Table 3-42 Regional balancing charges allocation: January through September 2010[13] (See 2009 SOM, Table 3-55)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$24,175,834 10.7%	$963,847 0.4%	$25,139,682 11.1%	$63,249,775 28.0%	$31,110,560 13.8%	$18,839,412 8.3%	$113,199,747 50.2%	$138,339,428 61.3%
East	$42,654,235 18.9%	$1,589,085 0.7%	$44,243,320 19.6%	$11,685,727 5.2%	$5,263,247 2.3%	$2,754,031 1.2%	$19,703,005 8.7%	$63,946,325 28.3%
West	$12,636,155 5.6%	$516,075 0.2%	$13,152,230 5.8%	$5,690,585 2.5%	$2,385,359 1.1%	$2,142,870 0.9%	$10,218,813 4.5%	$23,371,043 10.4%
Total	$79,466,225 35.2%	$3,069,008 1.4%	$82,535,232 36.6%	$80,626,087 35.7%	$38,759,166 17.2%	$23,736,312 10.5%	$143,121,565 63.4%	$225,656,797 100%

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The figures reported in this section reflect the figures at the time this report was created.

13 The total charges shown in Table 3-42 do not equal the total balancing charges shown in Table 3-41 because the totals in Table 3-41 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-42 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

Deviations

Allocation

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar year 2009 and January through September 2010 (See 2009 SOM, Table 3-56)

	2009 Deviations				2010 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,128,112	5,575,170	2,630,917	17,334,199	9,439,465	5,707,965	2,709,298	17,856,728
Feb	7,044,702	4,153,575	2,107,229	13,305,505	7,675,656	5,332,236	2,462,260	15,470,152
Mar	7,214,090	4,352,550	2,409,507	13,976,146	8,101,950	5,138,264	2,269,735	15,509,950
Apr	6,873,427	3,836,896	2,275,153	12,985,477	7,006,983	4,668,407	2,146,855	13,822,245
May	6,958,699	5,184,983	2,382,351	14,526,033	9,004,034	4,228,004	2,429,552	15,661,590
Jun	8,569,879	4,603,052	2,635,991	15,808,922	10,936,989	3,964,478	3,200,282	18,101,749
Jul	9,233,511	5,129,409	2,243,337	16,606,257	10,928,408	3,847,011	3,452,080	18,227,500
Aug	9,961,944	5,425,344	2,427,539	17,814,827	9,747,045	3,417,328	3,203,587	16,367,960
Sep	7,972,378	4,171,876	2,109,506	14,253,759	9,480,237	3,587,356	2,543,115	15,610,709
Oct	7,028,775	4,543,635	2,203,723	13,776,133				
Nov	6,742,675	4,248,221	2,193,013	13,183,910				
Dec	8,301,680	4,682,157	3,113,047	16,096,884				
Total	95,029,874	55,906,867	28,731,313	179,668,054	82,320,769	39,891,049	24,416,764	146,628,582
Share of Annual Deviations	52.9%	31.1%	16.0%	100.0%	56.1%	27.2%	16.7%	100.0%

Table 3-44 Regional charges determinants (MWh): January through September 2010 (See 2009 SOM, Table 3-57)

	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	Total
RTO	531,074,577	21,317,226	552,391,803	82,320,769	39,891,049	24,416,764	146,628,582	699,020,385
East	292,229,113	11,518,295	303,747,408	52,077,789	26,670,526	12,734,372	91,482,687	395,230,095
West	238,845,464	9,798,931	248,644,395	30,007,962	13,154,912	11,677,454	54,840,328	303,484,723

Balancing Operating Reserve Charge Rate

Figure 3-10 Daily RTO reliability and deviation rates ($/MWh): January through September 2010 (See 2009 SOM, Figure 3-14)

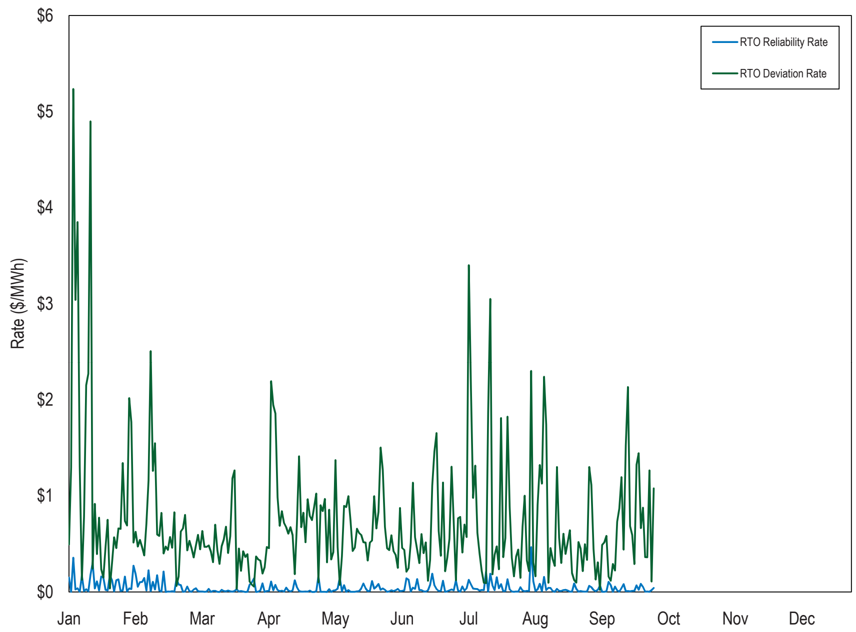


Figure 3-11 Daily regional reliability and deviation rates ($/MWh): January through September 2010 (See 2009 SOM, Figure 3-15)

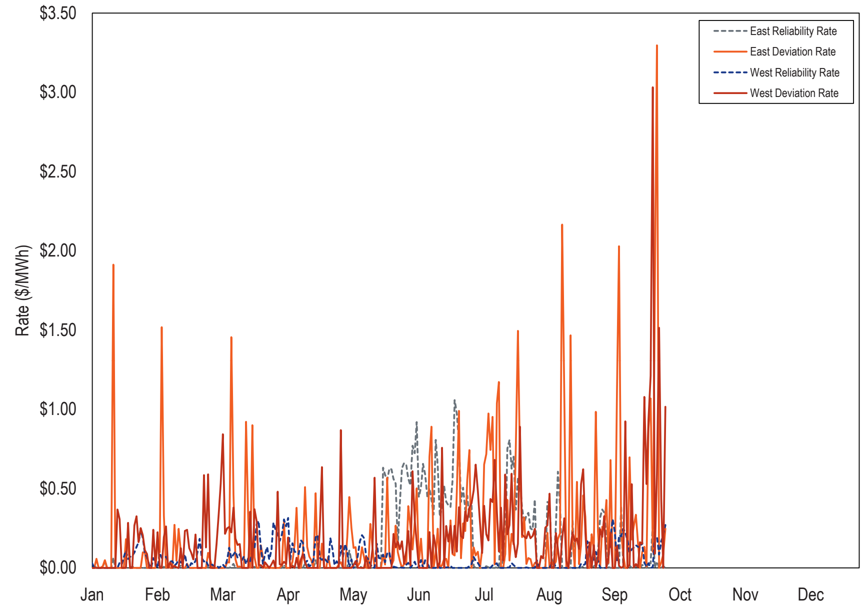


Table 3-45 Regional balancing operating reserve rates ($/MWh): January through September 2010 (See 2009 SOM, Table 3-58)

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.044	0.741
East	0.132	0.211
West	0.060	0.179

Operating Reserve Credits by Category

Figure 3-12 Operating reserve credits: January through September 2010 (See 2009 SOM, Figure 3-16)

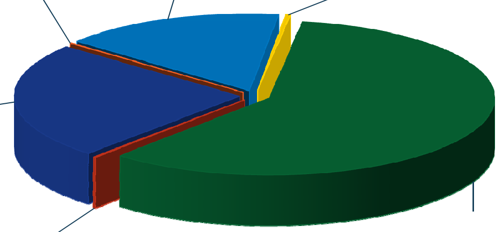


Table 3-46 Credits by month (By operating reserve market): January through September 2010 (See 2009 SOM, Table 3-59)[14]

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$34,146,809	$0	$3,333,858	$47,812,040
Feb	$11,382,585	$42,910	$14,715	$17,778,182	$77,139	$1,712,235	$31,007,765
Mar	$8,831,771	$5,115	$122,817	$13,931,307	$15,603	$1,971,841	$24,878,454
Apr	$7,633,141	$0	$93,253	$17,089,233	$0	$4,531,810	$29,347,437
May	$5,117,845	$9,462	$131,600	$23,182,507	$1,236	$15,665,943	$44,108,593
Jun	$3,469,143	$42,121	$33,923	$38,730,332	$196,537	$15,681,736	$58,153,793
Jul	$3,974,505	$627,284	$88,136	$36,589,423	$0	$23,571,309	$64,850,657
Aug	$3,391,194	$231,476	$66,535	$23,966,310	$0	$15,010,705	$42,666,220
Sep	$8,248,826	$185,065	$27,971	$25,726,609	$0	$13,630,437	$47,818,909
Oct							
Nov							
Dec							
Total	$62,248,544	$1,225,250	$628,972	$231,140,712	$290,515	$95,109,875	$390,643,869
Share of Credits	15.9%	0.3%	0.2%	59.2%	0.1%	24.3%	100.0%

14 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on customers' final bills.

Characteristics of Credits and Charges

Types of Units

Table 3-47 Credits by unit types (By operating reserve market): January through September 2010 (See 2009 SOM, Table 3-60)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	34.5%	0.0%	58.0%	7.4%	$86,036,382
Combustion Turbine	1.6%	0.5%	50.2%	47.8%	$132,420,673
Diesel	3.7%	0.0%	75.7%	20.7%	$514,429
Hydro	0.0%	0.0%	100.0%	0.0%	$371,295
Landfill	0.0%	0.0%	0.0%	100.0%	$13,784,394
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	19.6%	0.0%	73.0%	7.4%	$155,760,941
Wind Farm	0.0%	0.0%	100.0%	0.0%	$233,059

Table 3-48 Credits by operating reserve market (By unit type): January through September 2010 (See 2009 SOM, Table 3-61)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	47.7%	0.0%	21.6%	6.7%
Combustion Turbine	3.3%	100.0%	28.8%	66.5%
Diesel	0.0%	0.0%	0.2%	0.1%
Hydro	0.0%	0.0%	0.2%	0.0%
Landfill	0.0%	0.0%	0.0%	14.5%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	49.0%	0.0%	49.2%	12.2%
Wind Farm	0.0%	0.0%	0.1%	0.0%
Total	$62,248,544	$628,972	$231,133,780	$95,109,875

Geography of Balancing Credits and Charges

Table 3-49 Monthly balancing operating reserve charges and credits to generators (By location): January through September 2010 (See 2009 SOM, Table 3-65)

	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 Credits Percent of Total Operating Reserve Credits
Jan	$1,913,490	$249,304	$2,162,794	$29,069,084	$2,730,988	$31,800,072	$1,971,007	$263,791	$2,234,797	$5,077,725	$602,870	$5,680,596	8.6%	78.4%
Feb	$1,069,496	$138,378	$1,207,873	$14,194,451	$1,375,982	$15,570,433	$998,751	$132,679	$1,131,430	$3,583,730	$336,253	$3,919,983	6.9%	62.9%
Mar	$591,204	$125,590	$716,795	$8,223,758	$1,399,277	$9,623,035	$756,085	$166,509	$922,594	$5,707,549	$572,564	$6,280,114	6.4%	63.9%
Apr	$904,242	$342,520	$1,246,763	$12,334,741	$3,370,088	$15,704,830	$1,099,662	$393,474	$1,493,136	$4,754,491	$1,161,722	$5,916,213	9.0%	73.7%
May	$919,969	$1,219,952	$2,139,922	$17,646,849	$13,869,787	$31,516,636	$935,038	$1,196,289	$2,131,327	$5,535,658	$1,796,157	$7,331,815	9.7%	88.1%
Jun	$1,334,394	$1,453,614	$2,788,008	$33,621,482	$14,552,023	$48,173,505	$1,243,549	$1,370,749	$2,614,298	$5,108,850	$1,129,713	$6,238,563	8.9%	93.6%
Jul	$2,253,574	$2,323,169	$4,576,743	$29,626,646	$19,048,045	$48,674,691	$1,898,910	$2,015,996	$3,914,905	$6,962,777	$4,523,264	$11,486,041	12.5%	92.8%
Aug	$1,575,552	$1,449,229	$3,024,781	$18,625,295	$10,495,220	$29,120,516	$1,480,028	$1,643,754	$3,123,782	$5,341,015	$4,515,485	$9,856,499	13.5%	91.4%
Sep	$1,202,073	$952,764	$2,154,837	$16,755,277	$12,557,752	$29,313,029	$1,587,360	$1,200,168	$2,787,528	$8,971,332	$1,072,685	$10,044,017	10.2%	82.3%
Oct														
Nov														
Dec														
Average	49.6%	49.6%	49.6%	77.9%	83.5%	79.5%	50.4%	50.4%	50.4%	22.1%	16.5%	20.5%	9.5%	80.8%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-50 Regional balancing operating reserve credits: January through September 2010 (See 2009 SOM, Table 3-66)[15]

	Reliability Credits	Deviation Credits	Total Credits
RTO	$25,054,465	$112,894,940	$137,949,404
East	$44,243,320	$19,696,897	$63,940,218
West	$13,152,230	$10,140,624	$23,292,854
Total	$82,450,015	$142,732,461	$225,182,476

Table 3-51 Total deviations: January through September 2010 (See 2009 SOM, Table 3-67)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	82,321,091	39,891,049	24,437,806	146,649,946

Table 3-52 Charge allocation under old operating reserve construct: January through September 2010 (See 2009 SOM, Table 3-68)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	82,321,091	39,891,049	24,437,806	146,649,946
Balancing Rate ($/MWh)	1.536	1.536	1.536	1.536
Charges ($)	$126,404,867	$61,253,109	$37,524,499	$225,182,476

Table 3-53 Actual regional credits, charges, rates and charge allocation (MWh): January through September 2010 (See 2009 SOM, Table 3-69)

	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	$25,054,465	552,391,803	0.045	$25,054,465	$112,894,940	146,649,946	0.770	$112,894,940	$137,949,404
East	$44,243,320	303,747,408	0.146	$44,243,320	$19,696,897	91,501,468	0.215	$19,696,897	$63,940,218
West	$13,152,230	248,644,395	0.053	$13,152,230	$10,140,624	54,842,911	0.185	$10,140,624	$23,292,854
Total	$82,450,015	552,391,803	NA	$82,450,015	$142,732,461	146,649,946	NA	$142,732,461	$225,182,476

15 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on customers' final bills.

Table 3-54 Difference in total charges between old rules and new rules: January through September 2010 (See 2009 SOM, Table 3-70)

	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	$126,404,867	$61,253,109	$37,524,499	$225,182,476
Charges (Current)	$79,383,516	$3,066,499	$82,450,015	$80,384,439	$38,662,409	$23,685,613	$142,732,461
Difference	$79,383,516	$3,066,499	$82,450,015	($46,020,429)	($22,590,700)	($13,838,886)	($82,450,015)

Impact on decrement bids and incremental offers

Table 3-55 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through September 2010 (see 2009 SOM, Table 3-71)

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047
Feb	8,323,844	11,828,780	2,004,162	2,234,045
Mar	8,032,429	11,159,303	2,150,898	2,594,826
Apr	7,568,471	9,989,951	2,214,314	2,066,270
May	8,306,597	11,573,314	2,250,271	3,437,786
Jun	8,304,139	12,735,819	2,223,204	4,058,044
Jul	8,389,094	12,813,573	1,840,017	3,503,722
Aug	7,862,123	11,648,289	1,465,333	2,676,900
Sep	8,188,967	11,532,284	2,103,152	3,105,498
Total	73,267,095	106,310,830	18,715,203	27,129,138

Table 3-56 Comparison of balancing operating reserve charges to virtual bids: January through September 2010 (See 2009 SOM, Table 3-72)

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,708,013	$10,190,867	($2,517,146)
Feb	$5,382,344	$3,936,420	($1,445,924)
Mar	$4,612,939	$3,468,829	($1,144,110)
Apr	$6,530,621	$5,301,308	($1,229,313)
May	$13,792,538	$10,102,237	($3,690,302)
Jun	$18,748,323	$10,628,729	($8,119,594)
Jul	$18,164,125	$14,194,310	($3,969,815)
Aug	$9,792,633	$7,531,136	($2,261,497)
Sep	$12,912,392	$10,600,518	($2,311,874)
Total	$102,643,927	$75,954,353	($26,689,574)

Table 3-57 Summary of impact on virtual bids under balancing operating reserve allocation: January through September 2010 (See 2009 SOM, Table 3-73)

Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Under Old Rules ($/MWh)	Balancing Rate Under Current Rules ($/MWh)	Charges Under Old Rules	Charges Under Current Rules	Differerence
RTO	18,715,203	27,129,138	45,844,342	2.16	1.40	$102,643,926	$66,619,974	($36,023,952)
East	12,277,110	16,595,492	28,872,602	0.00	0.18	$0	$6,310,630	$6,310,630
West	6,372,482	10,298,629	16,671,111	0.00	0.00	$0	$3,023,749	$3,023,749

Segmented Make Whole Payments

Table 3-58 Impact of segmented make whole payments: December 2008 through October 2010 (See 2009 SOM, Table 3-74)

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,982,105	$33,924,489	$942,385
2010	Feb	$17,321,317	$17,609,133	$287,815
2010	Mar	$13,458,120	$13,672,172	$214,052
2010	Apr	$16,441,644	$17,036,058	$594,414
2010	May	$21,854,306	$23,455,721	$1,601,415
2010	Jun	$36,297,521	$38,885,349	$2,587,828
2010	Jul	$32,247,658	$37,049,632	$4,801,974
2010	Aug	$21,851,376	$24,333,948	$2,482,572
2010	Sep	$24,286,200	$25,683,305	$1,397,105
Total		$416,042,294	$439,126,259	$23,083,966

Table 3-59 Impact of segmented make whole payments (By unit type): January through September 2010 (See 2009 SOM, Table 3-75)[16]

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	7273	$6,198	$6,868	$670	$45,077,122	$49,950,143	$4,873,021
Large Frame Combustion Turbine (135 - 180 MW)	3215	$6,125	$7,049	$924	$19,691,696	$22,662,336	$2,970,640
Medium Frame Combustion Turbine (30 - 65 MW)	8181	$2,842	$3,204	$362	$23,246,625	$26,210,577	$2,963,951
Petroleum/Gas Steam (Pre-1985)	1020	$64,134	$65,436	$1,303	$65,416,233	$66,744,917	$1,328,684
Medium-Large Frame Combustion Turbine (65 - 125 MW)	2490	$4,864	$5,341	$477	$12,112,441	$13,299,362	$1,186,921
Petroleum/Gas Steam (Post-1985)	1877	$2,041	$2,370	$329	$3,830,891	$4,448,249	$617,358
Sub-Critical Coal	23922	$1,421	$1,445	$24	$34,002,003	$34,573,565	$571,562
Small Frame Combustion Turbine (0 - 29 MW)	3067	$1,633	$1,743	$110	$5,007,478	$5,344,633	$337,155
Diesel	3432	$96	$114	$18	$330,443	$390,511	$60,068
Super-Critical Coal	7204	$1,093	$1,093	$0	$7,874,597	$7,874,796	$199
Nuclear	1006	$0	$0	$0	$0	$0	$0
Hydro	576	$262	$262	$0	$150,717	$150,717	$0

Table 3-60 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through September 2010 (See 2009 SOM, Table 3-76)

Unit Type	Share of Increase
Combustion Turbines	50.0%
Combined-Cycle	32.7%
Steam	16.9%
Diesel	0.4%

16 In previous State of the Market reports, the columns *Average Daily Balancing Credits (Old and New rules)*, and *Total Balancing Credits (Old and Current rules)*, were the average and sums of only the observations in which there *was* a difference for a unit's balancing credits for the day under each method of calculation. The table now reflects the average and total credits for *all* observations in the time period, regardless of whether there was a difference for that day when calculating credits under each rule. While the *differences* between the new and old rules remain the same, the *Total Balancing Credits* columns now reflect the total sum of the time period's balancing operating reserves credits, as shown in Table 3-59.

Unit Operating Parameters

Table 3-61 Unit Parameter Limited Schedule Matrix (See 2009 SOM, Table 3-77)

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 65 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Table 3-62 Units receiving credits from a parameter limited schedule: January through September 2010 (See 2009 SOM, Table 3-78)

Unit Type	Number of Units	Observations
Combined-Cycle	3	8
Large Frame Combustion Turbine (135 - 180 MW)	6	81
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	113
Petroleum/Gas Steam (Pre-1985)	5	12
Sub-Critical Coal	25	250
Super-Critical Coal	1	1

Concentration of Unit Ownership for Operating Reserve Credits

Concentration of Operating Reserve Credits

Table 3-63 Unit operating reserve credits for units (By zone): January through September 2010 (See 2009 SOM, Table 3-80)

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$480,014	$3,971	$1,929,145	$3,524,005	$5,937,135	1.5%
AEP	$2,263,256	$13,296	$27,048,789	$2,825,550	$32,150,892	8.3%
AP	$1,452,413	$0	$4,118,792	$6,564,651	$12,135,856	3.1%
BGE	$4,395,983	$0	$8,633,699	$511,135	$13,540,817	3.5%
ComEd	$1,295,180	$4,080	$8,130,739	$5,885,245	$15,315,244	3.9%
DAY	$203,534	$0	$1,985,475	$290,918	$2,479,927	0.6%
DLCO	$2,349,144	$0	$9,902,666	$144,349	$12,396,159	3.2%
Dominion	$4,228,691	$0	$24,005,538	$50,802,524	$79,036,753	20.3%
DPL	$2,596,665	$10,337	$6,960,197	$1,502,119	$11,069,319	2.8%
JCPL	$2,307,738	$0	$5,394,610	$858,547	$8,560,894	2.2%
Met-Ed	$292,312	$0	$2,055,817	$562,727	$2,910,855	0.7%
PECO	$1,840,315	$2,095	$5,412,001	$2,356,875	$9,611,287	2.5%
PENELEC	$165,418	$27,409	$1,141,900	$2,334,790	$3,669,518	0.9%
Pepco	$3,898,184	$0	$65,271,187	$12,140,136	$81,309,507	20.9%
PPL	$133,000	$0	$5,234,632	$1,991,069	$7,358,702	1.9%
PSEG	$34,346,696	$567,782	$53,915,527	$2,815,234	$91,645,239	23.6%
RECO	$0	$0	$0	$0	$0	0.0%
External	$0	$0	$0	$0	$0	0.0%
Total	$62,248,544	$628,972	$231,140,712	$95,109,875	$389,128,103	100.0%

Table 3-64 Top 10 units and organizations receiving total operating reserve credits: January through September 2010 (See 2009 SOM, Table 3-81)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$29,445,765	7.6%	7.6%	$90,735,278	23.3%	23.3%
2	$21,957,259	5.6%	13.2%	$73,690,019	18.9%	42.3%
3	$21,272,780	5.5%	18.7%	$54,900,544	14.1%	56.4%
4	$18,256,867	4.7%	23.4%	$25,177,668	6.5%	62.8%
5	$14,092,829	3.6%	27.0%	$17,374,058	4.5%	67.3%
6	$12,524,539	3.2%	30.2%	$17,163,809	4.4%	71.7%
7	$10,284,726	2.6%	32.9%	$15,258,698	3.9%	75.6%
8	$4,868,869	1.3%	34.1%	$14,337,000	3.7%	79.3%
9	$4,783,701	1.2%	35.3%	$10,046,413	2.6%	81.9%
10	$4,253,062	1.1%	36.4%	$6,006,489	1.5%	83.4%

Table 3-65 Top 10 units and organizations receiving day-ahead generator credits: January through September 2010 (See 2009 SOM, Table 3-82)

	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	$13,648,456	21.9%	21.9%	$34,271,260	55.1%	55.1%
2	$8,019,436	12.9%	34.8%	$4,616,829	7.4%	62.5%
3	$7,133,477	11.5%	46.3%	$4,475,372	7.2%	69.7%
4	$2,824,506	4.5%	50.8%	$2,666,266	4.3%	73.9%
5	$1,875,580	3.0%	53.8%	$2,066,275	3.3%	77.3%
6	$1,812,089	2.9%	56.7%	$2,049,253	3.3%	80.6%
7	$1,797,737	2.9%	59.6%	$1,875,580	3.0%	83.6%
8	$1,358,925	2.2%	61.8%	$1,770,586	2.8%	86.4%
9	$1,280,779	2.1%	63.9%	$1,136,211	1.8%	88.2%
10	$1,136,211	1.8%	65.7%	$1,066,890	1.7%	90.0%

Table 3-66 Top 10 units and organizations receiving synchronous condensing credits: January through September 2010 (See 2009 SOM, Table 3-83)

	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	$47,478	7.5%	7.5%	$567,782	90.3%	90.3%
2	$47,176	7.5%	15.0%	$27,409	4.4%	94.6%
3	$46,849	7.4%	22.5%	$14,309	2.3%	96.9%
4	$44,323	7.0%	29.5%	$13,296	2.1%	99.0%
5	$44,031	7.0%	36.5%	$4,080	0.6%	99.7%
6	$37,699	6.0%	42.5%	$2,095	0.3%	100.0%
7	$31,142	5.0%	47.5%			
8	$27,863	4.4%	51.9%			
9	$27,604	4.4%	56.3%			
10	$25,858	4.1%	60.4%			

Table 3-67 Top 10 units and organizations receiving balancing generator credits: January through September 2010 (See 2009 SOM, Table 3-84)

	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	$22,306,460	9.7%	9.7%	$53,082,632	23.0%	23.0%
2	$21,272,051	9.2%	18.9%	$50,312,355	21.8%	44.7%
3	$17,918,553	7.8%	26.6%	$31,859,970	13.8%	58.5%
4	$10,024,439	4.3%	30.9%	$21,840,941	9.4%	68.0%
5	$9,695,765	4.2%	35.1%	$13,691,304	5.9%	73.9%
6	$8,277,061	3.6%	38.7%	$12,736,753	5.5%	79.4%
7	$6,073,193	2.6%	41.3%	$11,242,727	4.9%	84.3%
8	$3,717,281	1.6%	43.0%	$3,378,186	1.5%	85.7%
9	$2,708,497	1.2%	44.1%	$3,105,615	1.3%	87.1%
10	$2,649,408	1.1%	45.3%	$2,493,475	1.1%	88.1%

Table 3-68 Top 10 units and organizations receiving lost opportunity cost credits: January through September 2010 (See 2009 SOM, Table 3-85)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$4,528,271	4.8%	4.8%	$37,354,677	39.3%	39.3%
2	$4,415,166	4.6%	9.4%	$14,312,947	15.0%	54.3%
3	$3,584,978	3.8%	13.2%	$7,465,460	7.8%	62.2%
4	$2,923,880	3.1%	16.2%	$3,833,009	4.0%	66.2%
5	$2,633,988	2.8%	19.0%	$2,841,276	3.0%	69.2%
6	$2,558,140	2.7%	21.7%	$2,814,097	3.0%	72.1%
7	$2,325,374	2.4%	24.2%	$2,813,603	3.0%	75.1%
8	$2,055,519	2.2%	26.3%	$2,507,605	2.6%	77.7%
9	$2,050,391	2.2%	28.5%	$1,644,622	1.7%	79.5%
10	$1,995,456	2.1%	30.6%	$1,566,141	1.6%	81.1%