SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance in the first three months of 2011. 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.

Highlights

- Net revenues were generally higher for the CT and CC technologies through the first three months of 2011 compared to the same period in 2010, while net revenues for the CP technology were generally lower.

- The increases in net revenues for the CT and CC technologies were the result of higher energy market net revenues, and, in the case of zones which cleared in the RTO LDA for the 2009/2010 delivery year, higher capacity revenues.

- There were no scarcity pricing events in the first three months of 2011 under PJM's current Emergency Action based Scarcity Pricing Rules.

- Operating reserve charges increased $16,402,426, 14.9 percent, from $126,776,024 in the first three months of 2011 compared $110,373,599 in the first three months of 2010. Reliability credits increased $7,922,157, or 49.7 percent, in the first three months of 2011 compared to the first three months of 2010, and deviation credits increased $9,248,673, or 19.5 percent.

- Reliability charges were $23,854,871, 29.6 percent of all balancing operating reserve charges for the first three months 2011, and deviation charges were $56,624,124, 70.4 percent.

- RTO and Eastern deviation balancing operating reserve rates spiked during the fourth week of January 2011, reaching $9.1035/MWh and $2.2142/MWh as a result of the low temperatures, increased natural gas prices at Transco and Texas Eastern pipeline pricing points, and increased dispatch of units for operating reserves in the eastern regions of PJM. The price for natural gas at these pipeline pricing points on the peak day averaged $16.39/MMBtu, while the average price for pricing points on all other pipelines averaged $4.88. The fourth week of 2011, 7.8 percent of the days, accounted for 29.1 percent, $23,433,940, of balancing operating reserves for the first three months of 2011.

- Operating reserve credits for dispatchable transactions, which are a subset of pool-scheduled spot market import transactions, or balancing transaction operating reserve credits, for the months January through March 2011, were $1,273,235. The year with the next highest first quarter total balancing transaction operating reserve credits was in 2002, when credits were $98,065.

- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 50.3 percent of total operating reserve credits in the first three months of 2011, compared to 47.5 percent in the first three months 2010. In the first three months of 2011, the top generation owner received 47.9 percent of the total operating reserve credits paid.

- The regional concentration of balancing operating reserves also remains high for the first three months of 2011, with 44.5 percent of the credits being paid to units operating in the PSEG zone, 18.6 percent in Dominion, and 7.2 percent in the AEP zone.

- In the first three months of 2011, coal units provided 47.7 percent, nuclear units 35.7 percent and gas units 12.0 percent of total generation. Compared to the first three months of 2010, generation from coal units decreased 11.2 percent, and generation from nuclear units increased 2.8 percent. Generation from natural gas units increased 69.0 percent, and generation from oil units increased 101.7 percent.

- At the end of March 2011, 75,737 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 167,000 MW in 2011. Wind projects accounted for approximately 37,579 MW of capacity, 49.6 percent of the capacity in the queues, and combined-cycle projects account for 15,763 MW, 20.8 percent, of the capacity in the queues.

Recommendations

- In this 2011 *State of the Market Report for PJM: January through March*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is 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 is 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 the first three months of 2011, total net revenues were generally higher than in the same period in 2010 for the CT and CC technologies, and generally lower for the CP technology. While the results varied by zone, energy net revenues in all but one zone for the CT and in all zones for the CC technology showed an increase compared to the same period in 2010 while energy net revenues showed a decrease in all but three zones for the CP technology, reflecting the higher spread between LMP and the cost of natural gas compared to the spread between LMP and the cost of coal. 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 but BGE and Pepco had higher total net revenue in first three months of 2011 compared to the same period in 2010 (Table 3-7). For the new entrant CT, all zones but DLCO had higher energy net revenue. Ten zones had slightly lower capacity revenues and two zones had significantly lower capacity revenues, while five zones had higher capacity revenues.[1] The 2010/2011 Base Residual Auction (BRA) cleared with a single price across the entire market which was a significant reduction in price separation by location than prior BRAs 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 decreases or, in the case of SWMAAC, significant decreases, in capacity revenue available for the first three months of 2011, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity revenue. The DLCO control zone had a decrease in energy net revenues, which was more than offset by higher capacity revenues, resulting in an increase in total net 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 BRA. The decreases in capacity revenue in BGE and Pepco were not offset by increases in energy net revenue, leading to decreases in total net revenue in both zones.

  For the new entrant CC, all zones but BGE, PSEG and RECO had higher total net revenue in the first three months of 2011 compared to the same period in 2010 (Table 3-9). For the new entrant CC, all zones showed an increase in energy net revenue. For BGE, PSEG and RECO, higher energy net revenue did not offset decreases in capacity revenues.

1 This section discusses capacity revenues to new and existing units based on the clearing prices in Base Residual Auctions (BRA). It is not intended to reflect actual revenues associated with RPM.

For the new entrant coal plant (CP), all zones but AEP, AP and DAY had lower total net revenue through the first three months of 2011 compared to the same period in 2010 (Table 3-11). For the CP, all zones but AEP, AP, and BGE showed a decrease in energy net revenues. For AEP, higher capacity revenues in addition to higher energy net revenues contributed to an increase in total net revenues. For AP, higher energy revenues were only partially offset by lower capacity revenues. The BGE zone showed slightly higher energy net revenue which was more than offset by lower capacity revenue. The DAY zone showed slightly lower energy net revenue which was more than offset by higher capacity revenue.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through March 31, 2011, PJM installed capacity resources fell slightly from 166,410.2 MW on January 1 to 166,292.2 MW on March 31, a decrease of 118.0 MW or 0.1 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of March 31, 2011, 40.9 percent was coal; 28.7 percent was gas; 18.3 percent was nuclear; 6.5 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, 0.3 percent was wind, and 0.0 percent was solar.

- **Generation Fuel Mix.** In January through March 2011, coal provided 47.7 percent, nuclear 35.7 percent, gas 12.0 percent, oil 0.1 percent, hydroelectric 1.9 percent, solid waste 0.7 percent and wind 1.8 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.

Scarcity

- **Scarcity Pricing Events in the first three months of 2011.** PJM did not declare a scarcity event in the first three months of 2011.

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 payments, operating reserve credits 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, 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 three months of 2011.** Operating reserve charges increased 14.9 percent in the first three months of 2011 compared to the first three months of 2011. Reliability credits increased $7,922,157 in the first three months of 2011 compared to the first three months of 2010, and deviation credits increased $9,248,673.

  The overall increase in operating reserve charges in 2011 is comprised of a 5.5 percent decrease in day-ahead operating reserve charges, a 0.1 percent increase in synchronous condensing charges and a 5.4 percent increase in balancing operating reserve charges.

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.

In the first three months of 2011, energy market revenues were generally higher for new entrant combustion turbines and combined cycles, both using natural gas, as energy market prices increased in most zones, particularly MAAC zones, and, the average delivered price of natural gas decreased in most zones. Energy market net revenues for new entrant coal plants were lower in all zones except for AEP and AP as the average delivered price of low sulfur coal increased more than energy market prices in most zones. In AEP and AP, while average energy market prices changed slightly, increasing in AEP and decreasing in AP, the delivered price of coal in both zones decreased compared to the same period in 2010.

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 and other inframarginal units. With the exception of

DLCO, all zones show a higher frequency of hours with Real-Time LMP greater than $200 and more volatile Real-Time hourly LMPs through the first three months of 2011 compared to 2010. The PPL zone showed fifteen hours of Real-Time LMP greater than $200 through the first three months of 2011 compared to two hours in the same period of 2010, while the DLCO zone showed one hour through the first three months of 2011 compared to fifteen hours in the same period for 2010. As a result, the average increase in energy net revenue for a new entrant CT was 98 percent, and the increase in energy net revenue for PPL was 444 percent, while the decrease in DLCO energy net revenue was 47 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 the energy net revenues used as the offset in determining Capacity Market prices are higher than 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. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

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. In addition, coal plants face the most severe operational constraints, which can lead to operating during hours when the Real-Time LMP is less than the incremental costs of generation, decreasing energy revenues. In the first three months of 2011, coal prices increased significantly in most zones while the average Real-Time LMP increased only slightly in some zones and decreased in other zones, leading to lower energy revenues for coal plants. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. However, in 2011, compared to the 2010, as the average delivered price of coal increased while the average delivery price of natural gas decreased in most locations, coal plants received less inframarginal revenues when during hours when CCs and CTs ran in the first three months of 2011, which contributed to a decrease in 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, 2011 (See 2010 SOM, Table 3-3)

	Delivery Year 2010/2011			Delivery Year 2011/2012			RPM Revenue
Zone	LDA	$/MW-Day	$/MW in 2011	LDA	$/MW-Day	$/MW in 2011	2011 (Jan - Dec) $/MW
AECO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
AEP	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
AP	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
BGE	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
ComEd	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
DAY	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
DLCO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
Dominion	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
DPL	DPL South/RTO	$178.57	$26,964	RTO	$110.00	$23,540	$50,504
JCPL	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
Met-Ed	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PECO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PENELEC	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
Pepco	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PPL	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PSEG	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
RECO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PJM	NA	$174.42	$26,338	NA	$110.00	$23,540	$49,878

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-4)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$17,219	$15,686	(9%)
AEP	$9,184	$15,686	71%
AP	$17,219	$15,686	(9%)
BGE	$21,360	$15,686	(27%)
ComEd	$9,184	$15,686	71%
DAY	$9,184	$15,686	71%
DLCO	$9,184	$15,686	71%
Dominion	$9,184	$15,686	71%
DPL	$17,219	$16,071	(7%)
JCPL	$17,219	$15,686	(9%)
Met-Ed	$17,219	$15,686	(9%)
PECO	$17,219	$15,686	(9%)
PENELEC	$17,219	$15,686	(9%)
Pepco	$21,360	$15,686	(27%)
PPL	$17,219	$15,686	(9%)
PSEG	$17,219	$15,686	(9%)
RECO	$17,219	$15,686	(9%)
PJM	$13,902	$15,698	13%

New Entrant Net Revenues

Table 3-3 PJM 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 March 2010 and 2011 (See 2010 SOM, Table 3-5)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$2,018	$6,314	213%
AEP	$988	$1,916	94%
AP	$2,225	$5,420	144%
BGE	$3,262	$4,969	52%
ComEd	$446	$1,113	150%
DAY	$802	$2,180	172%
DLCO	$3,897	$2,069	(47%)
Dominion	$4,180	$4,219	1%
DPL	$2,518	$4,296	71%
JCPL	$2,117	$5,946	181%
Met-Ed	$1,892	$4,671	147%
PECO	$1,873	$4,851	159%
PENELEC	$942	$5,128	444%
Pepco	$6,995	$11,579	66%
PPL	$1,784	$6,905	287%
PSEG	$2,235	$4,032	80%
RECO	$1,422	$2,895	104%
PJM	$2,329	$4,618	98%

2 The energy net revenues presented for PJM for 2010 and 2011 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 3-4 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 March 2010 and 2011 (See 2010 SOM, Table 3-6)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$10,993	$18,454	68%
AEP	$5,023	$9,928	98%
AP	$10,097	$18,953	88%
BGE	$12,579	$14,271	13%
ComEd	$2,816	$5,281	88%
DAY	$4,710	$10,004	112%
DLCO	$7,809	$9,385	20%
Dominion	$12,787	$13,541	6%
DPL	$11,190	$14,567	30%
JCPL	$10,858	$17,557	62%
Met-Ed	$9,943	$14,401	45%
PECO	$10,255	$15,903	55%
PENELEC	$6,745	$18,215	170%
Pepco	$19,370	$28,232	46%
PPL	$9,352	$17,131	83%
PSEG	$10,709	$12,148	13%
RECO	$7,581	$8,555	13%
PJM	$9,577	$14,501	51%

Table 3-5 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 March 2010 and 2011 (See 2010 SOM, Table 3-7)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$38,430	$32,048	(17%)
AEP	$20,790	$22,697	9%
AP	$27,693	$34,176	23%
BGE	$17,367	$19,881	14%
ComEd	$33,265	$25,120	(24%)
DAY	$25,205	$22,116	(12%)
DLCO	$27,038	$7,006	(74%)
Dominion	$38,203	$29,635	(22%)
DPL	$39,554	$31,086	(21%)
JCPL	$37,869	$30,873	(18%)
Met-Ed	$36,661	$25,458	(31%)
PECO	$37,527	$28,063	(25%)
PENELEC	$31,838	$28,726	(10%)
Pepco	$40,850	$29,285	(28%)
PPL	$31,337	$28,491	(9%)
PSEG	$33,301	$21,927	(34%)
RECO	$35,558	$23,197	(35%)
PJM	$32,499	$25,870	(20%)

New Entrant Combustion Turbine

Table 3-6 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-8)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
Energy	$2,329	$4,618	98%
Capacity	$12,678	$14,315	13%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$596	$596	0%
Total	$15,603	$19,529	25%

Table 3-7 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-9)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$18,316	$21,215	16%
AEP	$9,959	$16,817	69%
AP	$18,522	$20,320	10%
BGE	$23,336	$19,869	(15%)
ComEd	$9,416	$16,013	70%
DAY	$9,773	$17,080	75%
DLCO	$12,867	$16,970	32%
Dominion	$13,151	$19,119	45%
DPL	$18,816	$19,547	4%
JCPL	$18,415	$20,847	13%
Met-Ed	$18,190	$19,572	8%
PECO	$18,171	$19,751	9%
PENELEC	$17,240	$20,028	16%
Pepco	$27,069	$26,479	(2%)
PPL	$18,082	$21,805	21%
PSEG	$18,533	$18,932	2%
RECO	$17,720	$17,795	0%
PJM	$15,603	$19,529	25%

New Entrant Combined Cycle

Table 3-8 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-10)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
Energy	$9,577	$14,501	51%
Capacity	$13,395	$15,125	13%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$800	$800	0%
Total	$23,772	$30,426	28%

Table 3-9 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-11)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$28,383	$34,367	21%
AEP	$14,671	$25,841	76%
AP	$27,487	$34,866	27%
BGE	$33,959	$30,184	(11%)
ComEd	$12,464	$21,195	70%
DAY	$14,358	$25,917	80%
DLCO	$17,457	$25,298	45%
Dominion	$22,435	$29,454	31%
DPL	$28,580	$30,851	8%
JCPL	$28,247	$33,470	18%
Met-Ed	$27,333	$30,314	11%
PECO	$27,645	$31,816	15%
PENELEC	$24,135	$34,128	41%
Pepco	$40,750	$44,145	8%
PPL	$26,742	$33,044	24%
PSEG	$28,099	$28,061	(0%)
RECO	$24,971	$24,468	(2%)
PJM	$23,772	$30,426	28%

New Entrant Coal Plant

Table 3-10 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-12)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
Energy	$32,499	$25,870	(20%)
Capacity	$12,537	$14,157	13%
Synchronized	$0	$0	0%
Regulation	$46	$5	(90%)
Reactive	$446	$446	0%
Total	$45,528	$40,477	(11%)

Table 3-11 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-13)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$54,439	$46,643	(14%)
AEP	$29,565	$37,298	26%
AP	$43,702	$48,784	12%
BGE	$37,095	$34,472	(7%)
ComEd	$42,095	$39,740	(6%)
DAY	$33,994	$36,718	8%
DLCO	$35,836	$21,598	(40%)
Dominion	$46,966	$44,227	(6%)
DPL	$55,588	$46,029	(17%)
JCPL	$53,880	$45,465	(16%)
Met-Ed	$52,672	$40,050	(24%)
PECO	$53,536	$42,654	(20%)
PENELEC	$47,878	$43,326	(10%)
Pepco	$60,587	$43,877	(28%)
PPL	$47,341	$43,083	(9%)
PSEG	$49,315	$36,518	(26%)
RECO	$51,573	$37,788	(27%)
PJM	$45,528	$40,477	(11%)

New Entrant Day-Ahead Net Revenues

Table 3-12 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-14)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$615	$3,623	489%
AEP	$109	$480	339%
AP	$774	$3,421	342%
BGE	$1,016	$3,154	210%
ComEd	$4	$75	1,622%
DAY	$23	$392	1,575%
DLCO	$320	$625	95%
Dominion	$2,354	$2,861	22%
DPL	$598	$3,088	416%
JCPL	$574	$4,267	643%
Met-Ed	$562	$3,023	438%
PECO	$579	$3,806	558%
PENELEC	$301	$3,245	978%
Pepco	$5,618	$10,519	87%
PPL	$550	$4,841	781%
PSEG	$302	$2,363	683%
RECO	$214	$1,619	656%
PJM	$854	$3,024	254%

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-15)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$11,513	$19,459	69%
AEP	$4,609	$9,733	111%
AP	$10,298	$19,953	94%
BGE	$13,401	$15,365	15%
ComEd	$1,969	$3,746	90%
DAY	$3,677	$9,359	155%
DLCO	$5,639	$8,623	53%
Dominion	$15,299	$14,544	(5%)
DPL	$9,945	$16,793	69%
JCPL	$11,720	$20,396	74%
Met-Ed	$10,287	$16,277	58%
PECO	$10,709	$18,740	75%
PENELEC	$8,349	$19,065	128%
Pepco	$22,395	$30,361	36%
PPL	$9,582	$18,580	94%
PSEG	$9,445	$13,828	46%
RECO	$7,712	$10,245	33%
PJM	$9,797	$15,592	59%

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-16)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$43,894	$34,967	(20%)
AEP	$22,087	$23,257	5%
AP	$30,595	$35,628	16%
BGE	$21,278	$21,131	(1%)
ComEd	$35,512	$24,778	(30%)
DAY	$26,139	$22,352	(14%)
DLCO	$27,126	$6,081	(78%)
Dominion	$45,952	$32,824	(29%)
DPL	$44,309	$36,205	(18%)
JCPL	$44,227	$34,709	(22%)
Met-Ed	$42,674	$28,388	(33%)
PECO	$43,596	$32,626	(25%)
PENELEC	$37,272	$30,006	(19%)
Pepco	$48,512	$31,807	(34%)
PPL	$37,298	$31,193	(16%)
PSEG	$38,041	$25,206	(34%)
RECO	$43,435	$30,047	(31%)
PJM	$37,173	$28,306	(24%)

Table 3-15 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through March 2011 (See 2010 SOM, Table 3-17)

	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	$36,925	$22,981	$13,944	38%
2011 (Jan - Mar)	$4,618	$3,024	$1,594	35%

Table 3-16 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 2010 and January through March 2011 (See 2010 SOM, Table 3-18)

	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	$88,275	$78,976	$9,299	11%
2011 (Jan - Mar)	$14,501	$15,592	($1,091)	(8%)

Table 3-17 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 2010 and January through March 2011 (See 2010 SOM, Table 3-19)

	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	$128,990	$126,772	$2,218	2%
2011 (Jan - Mar)	$25,870	$28,306	($2,436)	(9%)

Net Revenue Adequacy

Table 3-18 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)): Calendar years 2005 through 2010 (See 2010 SOM, Table 3-20)

	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	2010 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705	$131,044
CC	$93,549	$99,230	$143,600	$171,361	$173,174	$175,250
CP	$208,247	$267,792	$359,750	$492,780	$446,550	$465,455

New Entrant Combustion Turbine

Table 3-19 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-22)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$18,316	$21,215	$131,044	14%	16%
AEP	$9,959	$16,817	$131,044	8%	13%
AP	$18,522	$20,320	$131,044	14%	16%
BGE	$23,336	$19,869	$131,044	18%	15%
ComEd	$9,416	$16,013	$131,044	7%	12%
DAY	$9,773	$17,080	$131,044	7%	13%
DLCO	$12,867	$16,970	$131,044	10%	13%
Dominion	$13,151	$19,119	$131,044	10%	15%
DPL	$18,816	$19,547	$131,044	14%	15%
JCPL	$18,415	$20,847	$131,044	14%	16%
Met-Ed	$18,190	$19,572	$131,044	14%	15%
PECO	$18,171	$19,751	$131,044	14%	15%
PENELEC	$17,240	$20,028	$131,044	13%	15%
Pepco	$27,069	$26,479	$131,044	21%	20%
PPL	$18,082	$21,805	$131,044	14%	17%
PSEG	$18,533	$18,932	$131,044	14%	14%
RECO	$17,720	$17,795	$131,044	14%	14%
PJM	$15,603	$19,529	$131,044	12%	15%

Figure 3-1 New entrant CT real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): (See 2010 SOM, Figure 3-3)

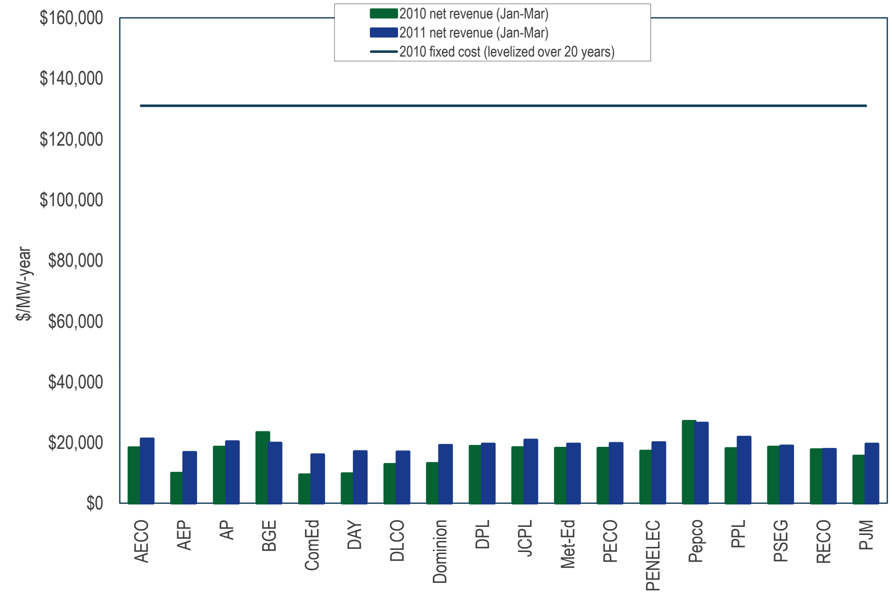
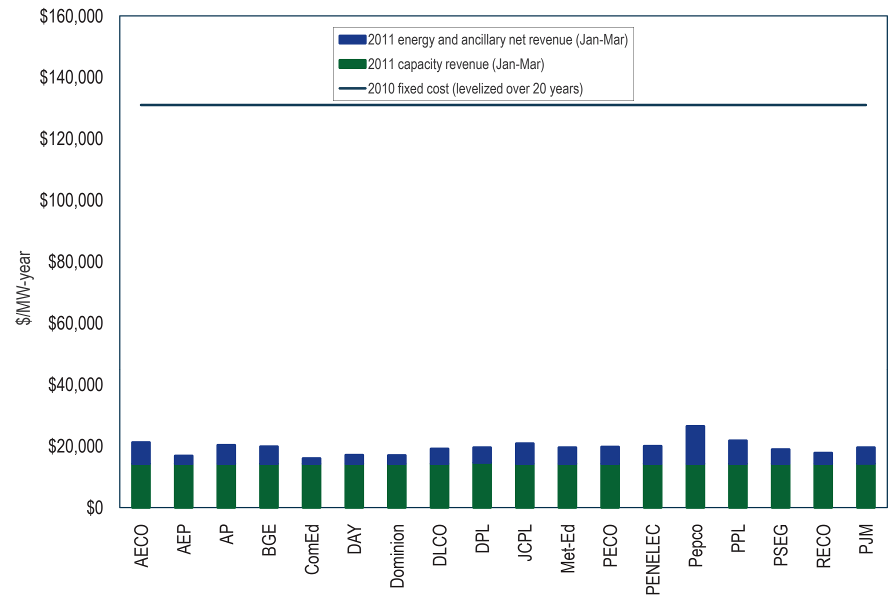


Figure 3-2 New entrant CT zonal real-time January through March 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-4)



New Entrant Combined Cycle

Table 3-20 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-24)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$28,383	$34,367	$175,250	16%	20%
AEP	$14,671	$25,841	$175,250	8%	15%
AP	$27,487	$34,866	$175,250	16%	20%
BGE	$33,959	$30,184	$175,250	19%	17%
ComEd	$12,464	$21,195	$175,250	7%	12%
DAY	$14,358	$25,917	$175,250	8%	15%
DLCO	$17,457	$25,298	$175,250	10%	14%
Dominion	$22,435	$29,454	$175,250	13%	17%
DPL	$28,580	$30,851	$175,250	16%	18%
JCPL	$28,247	$33,470	$175,250	16%	19%
Met-Ed	$27,333	$30,314	$175,250	16%	17%
PECO	$27,645	$31,816	$175,250	16%	18%
PENELEC	$24,135	$34,128	$175,250	14%	19%
Pepco	$40,750	$44,145	$175,250	23%	25%
PPL	$26,742	$33,044	$175,250	15%	19%
PSEG	$28,099	$28,061	$175,250	16%	16%
RECO	$24,971	$24,468	$175,250	14%	14%
PJM	$23,772	$30,426	$175,250	14%	17%

Figure 3-3 New entrant CC real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Figure 3-6)

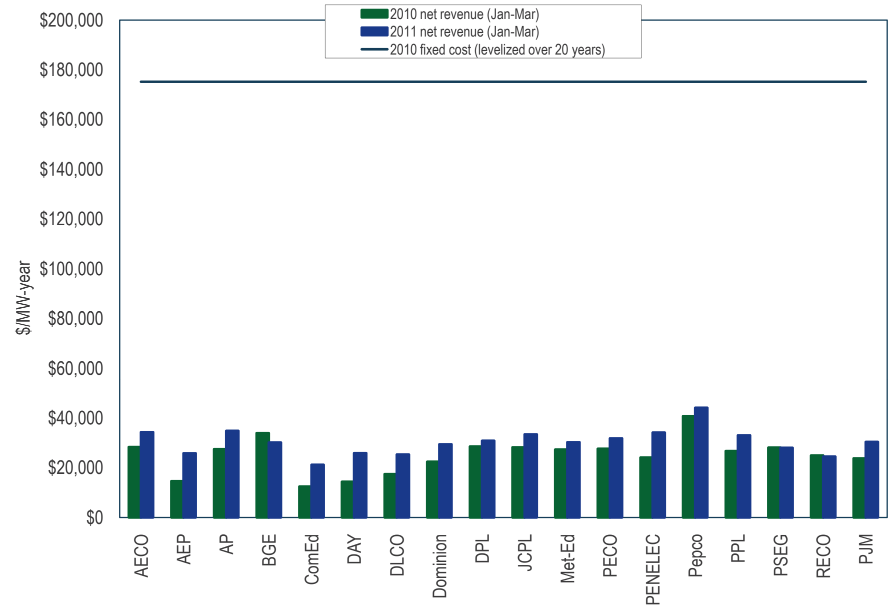
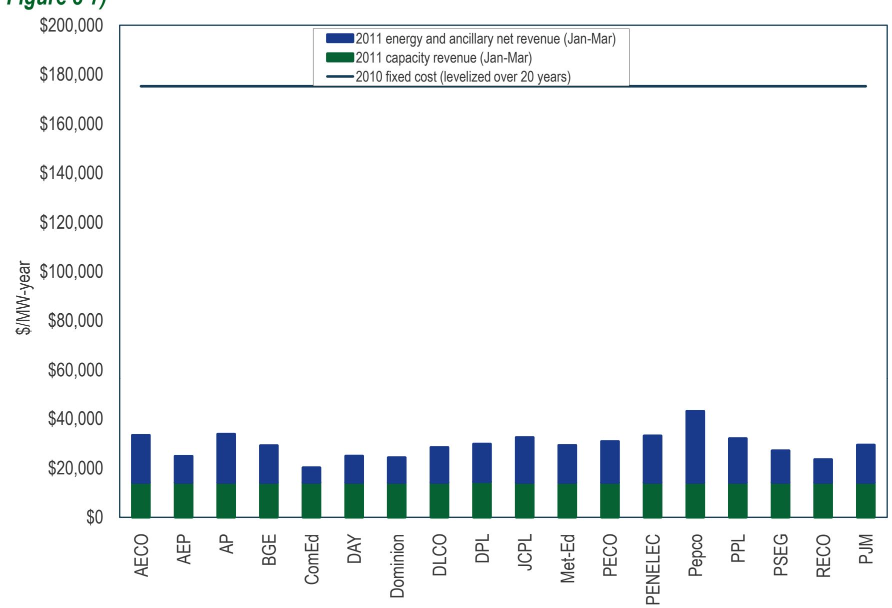


Figure 3-4 New entrant CC zonal real-time January through March 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-7)



New Entrant Coal Plant

Table 3-21 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-26)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$54,439	$46,643	$465,455	12%	10%
AEP	$29,565	$37,298	$465,455	6%	8%
AP	$43,702	$48,784	$465,455	9%	10%
BGE	$37,095	$34,472	$465,455	8%	7%
ComEd	$42,095	$39,740	$465,455	9%	9%
DAY	$33,994	$36,718	$465,455	7%	8%
DLCO	$35,836	$21,598	$465,455	8%	5%
Dominion	$46,966	$44,227	$465,455	10%	10%
DPL	$55,588	$46,029	$465,455	12%	10%
JCPL	$53,880	$45,465	$465,455	12%	10%
Met-Ed	$52,672	$40,050	$465,455	11%	9%
PECO	$53,536	$42,654	$465,455	12%	9%
PENELEC	$47,878	$43,326	$465,455	10%	9%
Pepco	$60,587	$43,877	$465,455	13%	9%
PPL	$47,341	$43,083	$465,455	10%	9%
PSEG	$49,315	$36,518	$465,455	11%	8%
RECO	$51,573	$37,788	$465,455	11%	8%
PJM	$45,528	$40,477	$465,455	10%	9%

Figure 3-5 New entrant CP real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Figure 3-9)

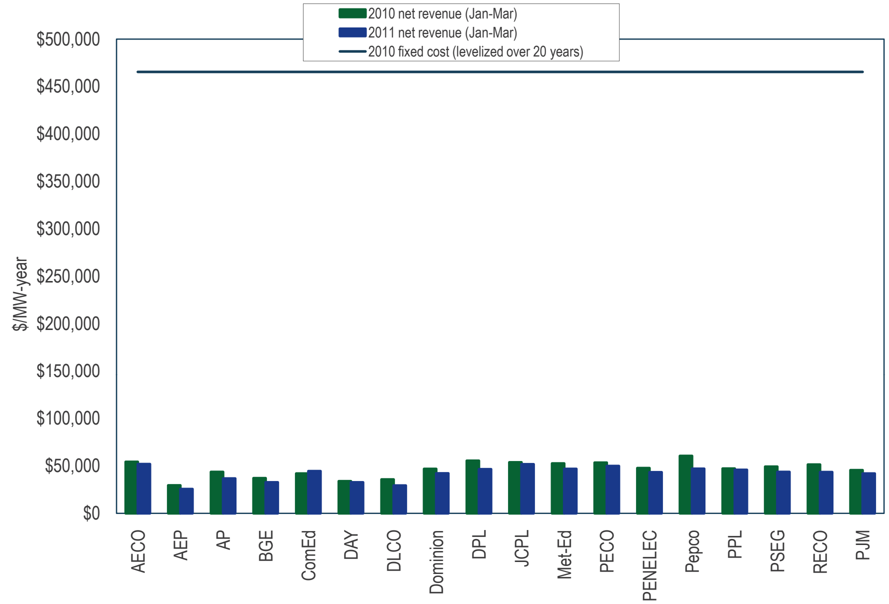
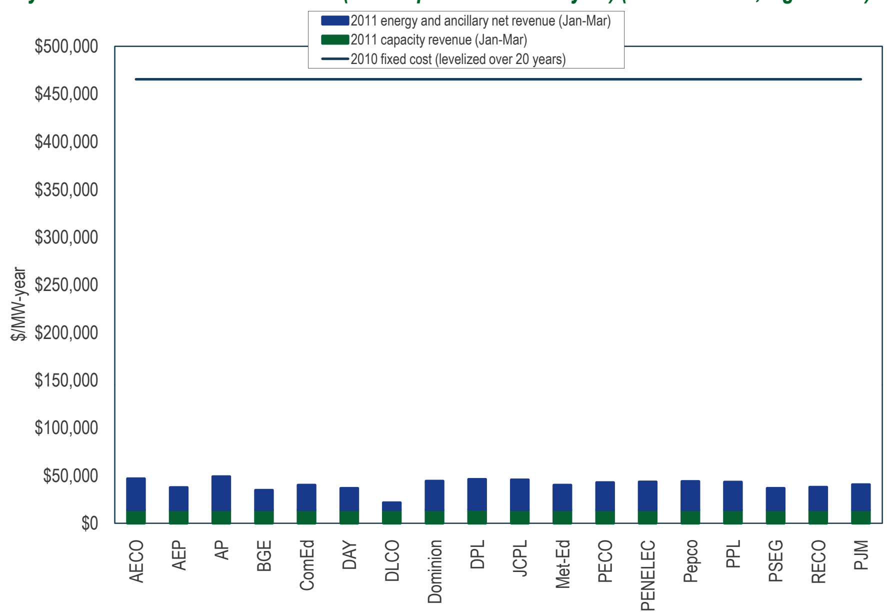


Figure 3-6 New entrant CP zonal real-time January through March 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-10)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-22 Table 3-22 PJM installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2011 (See 2010 SOM, Table 3-42)

	1-Jan-11		31-Jan-11		28-Feb-11		31-Mar-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,986.0	40.9%	67,966.1	40.8%	67,979.2	40.9%
Gas	47,736.6	28.7%	47,735.2	28.7%	47,726.0	28.7%	47,750.0	28.7%
Hydroelectric	7,954.5	4.8%	8,020.5	4.8%	8,018.4	4.8%	8,018.4	4.8%
Nuclear	30,552.2	18.4%	30,459.2	18.3%	30,732.2	18.5%	30,457.2	18.3%
Oil	10,949.5	6.6%	10,854.5	6.5%	10,854.1	6.5%	10,854.1	6.5%
Solar	0.0	0.0%	1.9	0.0%	1.9	0.0%	1.9	0.0%
Solid waste	680.1	0.4%	680.1	0.4%	680.1	0.4%	680.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	551.3	0.3%	551.3	0.3%
Total	166,410.2	100.0%	166,288.7	100.0%	166,530.1	100.0%	166,292.2	100.0%

Energy Production by Fuel Source

Table 3-23 PJM generation (By fuel source (GWh)): January through March 2010 and 2011[3] (See 2010 SOM, Table 3-43)

	2010 (Jan-Mar)		2011 (Jan-Mar)		Change
	GWh	Percent	GWh	Percent	in Output
Coal	98,126.2	53.8%	87,182.8	47.7%	(11.2%)
Standard Coal	95,374.4	52.3%	84,234.9	46.1%	0.0%
Waste Coal	2,751.9	1.5%	2,947.9	1.6%	0.0%
Nuclear	63,428.4	34.8%	65,194.7	35.7%	2.8%
Gas	13,000.5	7.1%	21,973.5	12.0%	69.0%
Natural Gas	12,615.9	6.9%	21,552.9	11.8%	70.8%
Landfill Gas	384.6	0.2%	420.6	0.2%	9.4%
Biomass Gas	0.1	0.0%	0.0	0.0%	(70.5%)
Hydroelectric	4,266.2	2.3%	3,524.1	1.9%	(17.4%)
Wind	2,158.3	1.2%	3,220.9	1.8%	49.2%
Waste	1,199.0	0.7%	1,257.9	0.7%	4.9%
Solid Waste	931.7	0.5%	932.8	0.5%	0.1%
Miscellaneous	267.3	0.1%	325.1	0.2%	21.6%
Oil	113.4	0.1%	228.7	0.1%	101.7%
Heavy Oil	80.6	0.0%	190.1	0.1%	135.9%
Light Oil	28.6	0.0%	35.4	0.0%	23.8%
Diesel	4.0	0.0%	2.4	0.0%	(40.7%)
Kerosene	0.2	0.0%	0.9	0.0%	302.7%
Jet Oil	0.0	0.0%	0.0	0.0%	(59.5%)
Solar	0.8	0.0%	7.0	0.0%	810.2%
Battery	0.1	0.0%	0.1	0.0%	12.5%
Total	182,293.0	100.0%	182,589.8	100.0%	0.2%

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

Table 3-24 PJM capacity factor (By unit type (GWh)); January through March 2010 and 2011 (New table)

	2010 (Jan-Mar)		2011 (Jan-Mar)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.1	4.5%	0.1	5.1%
Combined Cycle	11,870.7	24.5%	20,893.0	42.3%
Combustion Turbine	459.7	0.8%	483.1	0.8%
Diesel	346.6	22.9%	365.8	24.0%
Nuclear	63,428.4	93.8%	65,194.7	96.4%
Pumped Storage Hydro	1,741.2	14.7%	1,652.5	13.9%
Run of River Hydro	2,525.0	50.3%	1,871.7	37.3%
Solar	0.8	11.9%	7.0	13.1%
Steam	99,900.0	57.4%	89,005.6	51.1%
Wind	2,158.3	31.3%	3,220.9	34.5%

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through March 2011[4] (See 2010 SOM, Table 3-44)

	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	2,097
2011 (Jan-Mar)	1,034

PJM Generation Queues

Table 3-26 Queue comparison (MW): March 31, 2011 vs. December 31, 2010 (See 2010 SOM, Table 3-44)

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	22,431	(2,947)	(12%)
2012	13,261	13,390	129	1%
2013	11,244	11,004	(240)	(2%)
2014	13,888	13,563	(325)	(2%)
2015	5,960	7,996	2,036	34%
2016	1,350	2,020	670	50%
2017	2,140	2,140	0	0%
2018	3,194	3,194	0	0%
Total	76,415	75,737	(678)	(1%)

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 March 31, 2011[5, 6] (See 2010 SOM, Table 3-46)

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	4,646	0	15,833	20,478
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	1,155	21,461	23,102
H Expired 31-Jan-02	0	703	0	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	148	160	2,336	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	1,678	1,346	471	4,077	7,572
P Expired 31-Jan-06	513	2,500	630	5,058	8,701
Q Expired 31-Jul-06	1,759	1,141	3,021	8,693	14,614
R Expired 31-Jan-07	4,887	649	1,225	15,994	22,755
S Expired 31-Jul-07	3,137	1,614	1,168	14,975	20,893
T Expired 31-Jan-08	11,399	623	750	14,845	27,617
U Expired 31-Jan-09	6,701	212	294	26,106	33,312
V Expired 31-Jan-10	12,387	70	244	4,218	16,918
W Expired 31-Jan-11	18,497	0	166	5,456	24,119
X Expires 31-Jan-12	3,927	0	0	0	3,927
Total	66,281	27,517	9,456	215,841	319,095

Table 3-28 Average project queue times (days): At March 31, 2011 (See 2010 SOM, Table 3-47)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	782	602	0	4,420
In-Service	785	646	0	3,287
Suspended	2,431	735	890	3,849
Under Construction	1,139	917	0	4,370
Withdrawn	515	495	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 March 31, 2011 (See 2010 SOM, Table 3-48)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
AECO	0	1,255	775	17	0	0	1,006	665	2,139	5,856
AEP	0	1,845	580	7	170	84	166	2,482	13,475	18,809
AP	32	958	0	6	78	0	523	1,297	1,180	4,074
BGE	0	0	0	29	0	1,640	0	132	0	1,801
ComEd	20	1,080	1,038	84	23	750	49	1,366	15,612	20,021
DAY	0	0	0	2	112	0	60	12	1,440	1,626
DLCO	0	0	0	0	0	91	0	0	0	91
Dominion	32	1,960	595	21	3	1,774	134	302	1,640	6,461
DPL	0	309	109	0	0	0	208	43	645	1,313
JCPL	0	1,965	27	33	0	0	1,139	0	0	3,164
Met-Ed	23	1,760	7	23	0	24	150	0	0	1,987
PECO	2	663	27	17	0	510	26	0	0	1,246
PENELEC	0	0	65	15	0	0	132	90	930	1,232
Pepco	0	1,479	0	6	0	0	46	0	0	1,531
PPL	20	0	139	13	3	1,600	167	33	498	2,473
PSEG	0	2,490	1,077	3	0	50	307	105	20	4,051
Total	129	15,763	4,439	278	388	6,523	4,112	6,526	37,579	75,737

5 The *2011 Quarterly State of the Market Report for PJM: January through March* 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 3-30 Capacity additions in active or under-construction queues by LDA (MW): At March 31, 2011[7] (See 2010 SOM, Table 3-49)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
EMAAC	2	6,681	2,015	71	0	560	2,686	813	2,804	15,631
SWMAAC	0	1,479	0	35	0	1,640	46	132	0	3,332
WMAAC	43	1,760	211	52	3	1,624	449	123	1,428	5,692
Non-MAAC	84	5,843	2,213	121	386	2,699	931	5,459	33,347	51,082
Total	129	15,763	4,439	278	388	6,523	4,112	6,526	37,579	75,737

Table 3-31 Existing PJM capacity: At March 31, 2011[8] (By zone and unit type (MW)) (See 2010 SOM, Table 3-50)

	Battery	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Wind	Total
AECO	0	0	608	23	0	0	0	1,264	8	1,902
AEP	0	4,355	3,668	57	1,005	2,106	0	21,568	1,053	33,811
AP	0	1,129	1,180	36	108	0	0	7,773	566	10,792
BGE	0	0	841	7	0	1,705	0	3,026	0	5,578
ComEd	0	1,814	7,129	111	0	10,376	0	6,791	1,945	28,165
DAY	0	0	1,364	52	0	0	1	3,572	0	4,989
DLCO	0	244	45	0	6	1,777	0	1,239	0	3,311
Dominion	0	3,173	3,853	161	3,558	3,494	0	8,484	0	22,723
DPL	0	1,117	1,755	96	0	0	0	1,919	0	4,887
External	0	974	1,574	0	70	439	0	9,470	185	12,712
JCPL	0	1,390	1,225	25	400	615	0	318	0	3,972
Met-Ed	0	2,000	406	23	20	805	0	890	0	4,143
PECO	1	2,552	836	7	1,642	4,509	3	2,129	0	11,679
PENELEC	0	0	287	39	505	0	0	6,834	555	8,219
Pepco	0	230	1,325	12	0	0	0	4,706	0	6,273
PPL	0	1,700	618	63	571	2,375	0	5,532	220	11,078
PSEG	0	2,921	2,860	0	5	3,553	58	2,535	0	11,932
Total	1	23,598	29,572	711	7,890	31,753	63	88,048	4,531	186,167

7 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
8 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 (MW) by age: at March 31, 2011 (See 2010 SOM, Table 3-51)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 11	1	18,253	14,734	377	10	0	1,192	63	4,521	39,150
11 to 20	0	4,047	6,325	126	49	0	5,613	0	10	16,170
21 to 30	0	857	1,084	38	3,404	15,210	7,233	0	0	27,825
31 to 40	0	244	4,195	24	105	15,062	31,769	0	0	51,399
41 to 50	0	198	3,234	143	2,915	1,482	24,868	0	0	32,839
51 to 60	0	0	0	4	348	0	15,267	0	0	15,619
61 to 70	0	0	0	0	0	0	1,956	0	0	1,956
71 to 80	0	0	0	0	344	0	95	0	0	439
81 to 90	0	0	0	0	488	0	54	0	0	542
91 to 100	0	0	0	0	190	0	0	0	0	190
101 and over	0	0	0	0	37	0	0	0	0	37
Total	1	23,598	29,572	711	7,890	31,753	88,048	63	4,531	186,167

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[9] (See 2010 SOM, Table 3-52)

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%	2	3	0.0%
	Combined Cycle	0	0.0%	7,980	23.2%	6,681	14,662	33.2%
	Combustion Turbine	955	12.2%	7,285	21.2%	2,015	8,344	18.9%
	Diesel	49	0.6%	150	0.4%	71	171	0.4%
	Hydroelectric	2,042	26.0%	2,047	6.0%	0	2,047	4.6%
	Nuclear	615	7.8%	8,676	25.2%	560	8,622	19.5%
	Solar	0	0.0%	61	0.2%	2,686	2,747	6.2%
	Steam	4,192	53.4%	8,164	23.8%	813	4,785	10.8%
	Wind	0	0.0%	8	0.0%	2,804	2,812	6.4%
	EMAAC Total	7,853	100.0%	34,372	100.0%	15,631	44,193	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	1,479	1,709	15.0%
	Combustion Turbine	540	14.2%	2,165	18.3%	0	1,625	14.3%
	Diesel	0	0.0%	19	0.2%	35	54	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	29.4%
	Solar	0	0.0%	0	0.0%	46	46	0.4%

Table 3-33 continued next page.

9 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.

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	40.4%
	SWMAAC Total	3,807	100.0%	11,851	100.0%	3,332	11,377	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	43	43	0.2%
	Combined Cycle	0	0.0%	3,700	15.8%	1,760	5,460	24.1%
	Combustion Turbine	296	4.3%	1,310	5.6%	211	1,225	5.4%
	Diesel	35	0.5%	125	0.5%	52	141	0.6%
	Hydroelectric	444	6.5%	1,096	4.7%	3	1,098	4.8%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	21.2%
	Solar	0	0.0%	0	0.0%	449	449	2.0%
	Steam	6,042	88.6%	13,256	56.6%	123	7,336	32.4%
	Wind	0	0.0%	734	3.1%	1,428	2,162	9.5%
	WMAAC Total	6,817	100.0%	23,399	100.0%	5,692	22,675	100.0%
Non-MAAC	Battery	0	0.0%	0	0.0%	84	84	0.1%
	Combined Cycle	0	0.0%	11,688	10.0%	5,843	17,531	12.5%
	Combustion Turbine	709	2.6%	18,812	16.2%	2,213	20,316	14.5%
	Diesel	48	0.2%	418	0.4%	121	490	0.4%
	Hydroelectric	1,401	5.0%	4,747	4.1%	386	3,731	2.7%
	Nuclear	0	0.0%	18,192	15.6%	2,699	20,891	14.9%
	Solar	0	0.0%	1	0.0%	931	933	0.7%
	Steam	25,632	92.2%	58,896	50.6%	5,459	38,723	27.7%
	Wind	0	0.0%	3,699	3.2%	33,347	37,046	26.5%
	Non-MAAC Total	27,790	100.0%	116,453	100.0%	51,082	139,746	100.0%
All Areas	Total	46,267		186,076		75,737	217,990	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through March 2011 (See 2010 SOM, Table 3-53)[10]

Type of Resource	Capacity Factor	Total Run Hours	Peak Capacity Factor	Peak Run Hours	Installed Capacity (MW)
Energy-Only Resource	30.6%	34,711	N/A	N/A	1,160
Capacity Resource	35.6%	77,724	199.8%	9,102	3,371
All Units	34.5%	112,435	N/A	9,102	4,531

10 Peak capacity factor refers to cleared RPM MW in peak periods (peak hours during January, February, June, July, and August).

Table 3-35 Wind resources in real time offering at a negative price in PJM, January through March 2011 (See 2010 SOM, Table 3-54)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	1,104.9	485	2.85%
All Wind	2,491.1	615	3.62%

Figure 3-7 Average hourly real-time generation of wind units in PJM, January through March 2011 (See 2010 SOM, Figure 3-13)

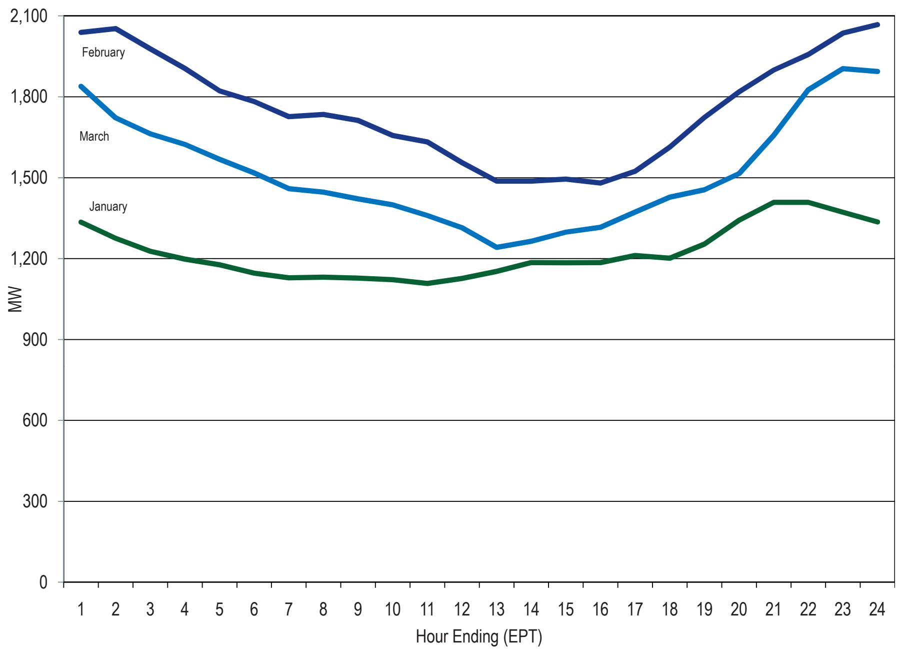


Table 3-36 Capacity factor of wind units in PJM by month, Calendar years 2010 to March 31, 2011[11] (See 2010 SOM, Table 3-55)

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	818,423.9	35.7%	909,690.8	29.1%
February	612,044.4	28.6%	1,181,192.0	40.5%
March	727,819.1	29.5%	1,130,037.9	35.0%
April	881,317.4	35.5%		
May	670,571.5	26.2%		
June	472,775.6	18.6%		
July	380,114.8	14.4%		
August	330,818.7	12.1%		
September	705,289.0	24.0%		
October	1,006,233.1	32.5%		
November	1,088,610.5	35.5%		
December	1,118,789.3	35.3%		
Annual	8,812,807.2	27.4%	3,220,920.7	34.5%

Table 3-37 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): January through March 2011 (See 2010 SOM, Table 3-56)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	32.5%				32.5%
	Average Wind Generation	1,407.3				1,407.3
	Average Load	86,939.1				86,939.1
Off-Peak	Capacity Factor	36.2%				36.2%
	Average Wind Generation	1,568.1				1,568.1
	Average Load	75,243.8				75,243.8

11 Capacity factor shown in Table 3-36 is based on all hours in January through March, 2011.

Figure 3-8 Average hourly day-ahead generation of wind units in PJM, January through March 2011 (See 2010 SOM, Figure 3-14)

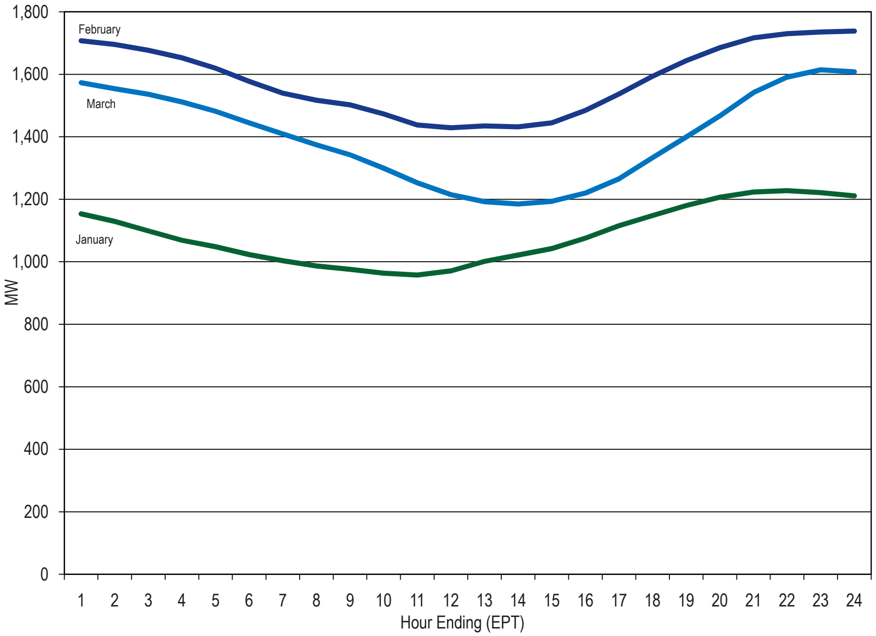
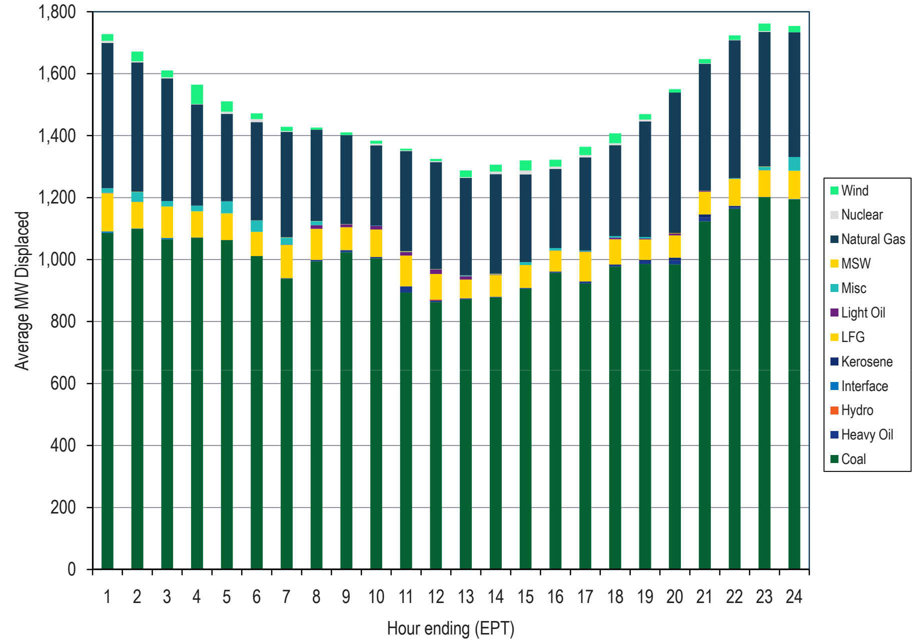


Figure 3-9 Marginal fuel at time of wind generation in PJM, January through March 2011 (See 2010 SOM, Figure 3-15)



Environmental Regulatory Impacts

Emission Allowances Trading

Figure 3-10 Spot average emission price comparison: Calendar year 2010 to March 31, 2011 (See 2010 SOM, Figure 3-16)

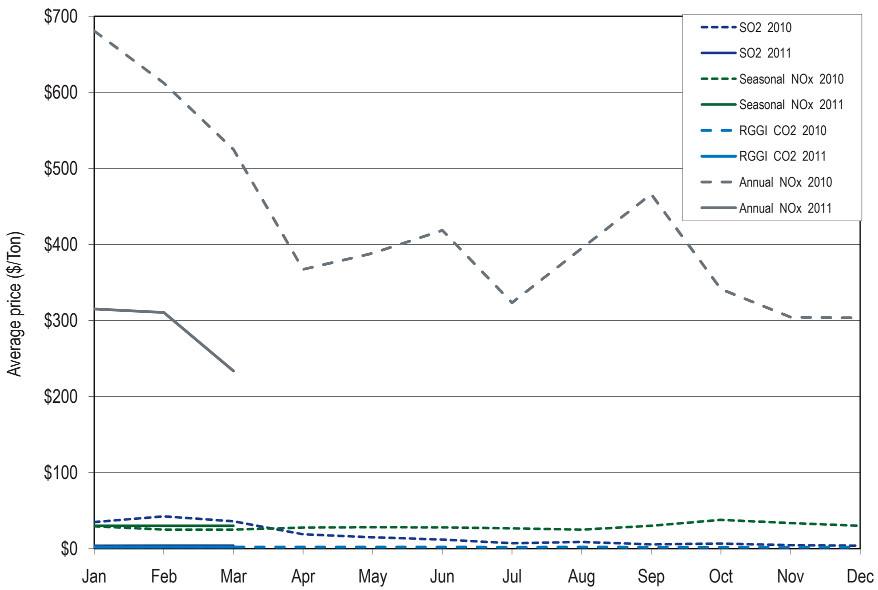


Table 3-38 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2010 SOM, Table 3-57)[12]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813

12 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed April 1, 2011).

Emission Controlled Capacity in the PJM Region

Table 3-39 SO_2 emission controls (FGD) by unit type (MW), as of March 31, 2011 (See 2010 SOM, Table 3-58)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	48,996.7	27,224.0	76,220.7	64.3%
Combined Cycle	0.0	23,598.4	23,598.4	0.0%
Combustion Turbine	0.0	29,463.2	29,463.2	0.0%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	0.0	10,837.0	10,837.0	0.0%
Total	48,996.7	91,465.0	140,461.7	34.9%

Table 3-40 NO_x emission controls by unit type (MW), as of March 31, 2011 (See 2010 SOM, Table 3-59)

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	74,072.9	2,147.8	76,220.7	97.2%
Combined Cycle	23,448.4	150.0	23,598.4	99.4%
Combustion Turbine	24,041.5	5,421.7	29,463.2	81.6%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	5,808.1	5,028.9	10,837.0	53.6%
Total	127,370.9	13,090.8	140,461.7	90.7%

Table 3-41 Particulate emission controls by unit type (MW), as of March 31, 2011 (See 2010 SOM, Table 3-60)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	74,621.7	1,599.0	76,220.7	97.9%
Combined Cycle	0.0	23,598.4	23,598.4	0.0%
Combustion Turbine	0.0	29,463.2	29,463.2	0.0%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	3,047.0	7,790.0	10,837.0	28.1%
Total	77,668.7	62,793.0	140,461.7	55.3%

Renewable Portfolio Standards

Table 3-42 Renewable standards of PJM jurisdictions to 2021[13,14] (See 2010 SOM, Table 3-61)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana	No Standard										
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

Table 3-43 Solar renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-62)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

13 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

14 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

Table 3-44 Additional renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-63)

Jurisdiction		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)	306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste		0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)		170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

Table 3-45 Renewable alternative compliance payments in PJM jurisdictions: 2010 (See 2010 SOM, Table 3-64)

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 3-46 Renewable generation by jurisdiction and renewable resource type (GWh): January through March 2011 (See 2010 SOM, Table 3-65)

Jurisdiction	Battery	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	0.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	13.8	27.6
Indiana	0.0	0.0	0.0	11.0	0.0	0.0	0.0	831.6	842.5	842.5
Illinois	0.0	37.9	0.0	0.0	0.0	2.4	0.0	1,378.2	1,416.1	1,418.5
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	21.3	0.0	565.0	0.0	138.0	0.0	91.3	677.6	815.6
Michigan	0.0	7.9	0.0	14.8	0.0	0.0	0.0	0.0	22.7	22.7
New Jersey	0.0	69.5	132.4	7.4	6.0	339.3	0.0	3.3	86.3	558.0
North Carolina	0.0	0.0	0.0	92.2	0.0	0.0	0.0	0.0	92.2	92.2
Ohio	0.0	9.7	0.0	24.8	0.2	0.0	0.0	0.0	34.7	34.7
Pennsylvania	0.1	214.9	503.4	677.7	0.8	496.0	2,656.5	590.0	1,483.3	5,139.3
Tennessee	0.0	0.0	0.0	0.0	0.0	84.7	0.0	0.0	0.0	84.7
Virginia	0.0	45.6	1,016.7	180.3	0.0	301.9	0.0	0.0	225.9	1,544.4
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	0.0	298.5	0.0	0.0	277.2	326.6	625.1	902.4
Total	0.1	420.6	1,652.5	1,871.7	7.0	1,362.4	2,933.7	3,220.9	5,520.2	11,468.9

Table 3-47 PJM renewable capacity by jurisdiction (MW), on March 31, 2011 (See 2010 SOM, Table 3-66)

Jurisdiction	Battery	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	0.0	8.1	1,827.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,848.1
Illinois	0.0	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	60.0	24.9	129.0	69.0	0.0	1,162.0	0.0	109.0	0.0	120.0	1,673.9
Michigan	0.0	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
New Jersey	0.0	0.0	74.9	0.0	0.0	400.0	5.0	58.4	191.1	0.0	7.5	736.9
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	0.0	3,132.7	4.5	0.0	18.0	0.0	116.2	1.1	0.0	0.0	0.0	3,272.5
Pennsylvania	1.0	35.0	199.4	2,240.3	0.0	2,575.0	664.9	3.0	280.0	1,418.9	790.0	8,207.5
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	0.0	109.1	80.0	17.0	3,588.0	426.1	0.0	231.0	0.0	0.0	4,451.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	318.0	0.0	0.0	0.0	0.0	257.6	0.0	0.0	130.0	430.5	1,136.1
PJM Total	1.0	3,545.7	493.8	4,276.3	117.0	6,563.0	2,968.9	62.5	976.1	1,548.9	4,531.1	25,084.3

Table 3-48 Renewable capacity by jurisdiction, non-PJM units registered in GATS[15,16] (MW), on March 31, 2011 (See 2010 SOM, Table 3-67)

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	9.1	0.0	0.1	9.2
Illinois	0.0	8.7	97.8	0.0	0.0	0.0	10.5	0.0	302.5	419.5
Indiana	0.0	0.0	26.4	0.0	679.1	0.0	0.2	0.0	0.0	705.7
Kentucky	0.0	2.0	16.0	0.0	0.0	0.0	0.2	88.0	0.0	106.2
Maryland	0.0	0.0	5.0	0.0	0.0	0.0	14.8	10.0	0.0	29.8
Michigan	0.0	0.0	37.0	0.0	0.0	0.0	0.1	0.0	0.0	37.1
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	36.5	0.0	0.0	23.3	234.6	0.0	0.2	294.5
New York	0.0	179.9	0.0	0.0	0.0	0.0	0.4	0.0	0.0	180.3
North Carolina	0.0	225.0	5.3	0.0	0.0	0.0	2.0	0.0	0.0	232.3
Ohio	60.0	1.0	42.4	52.6	45.0	0.0	19.9	109.3	9.7	340.0
Pennsylvania	0.0	0.2	5.4	4.8	85.5	0.3	56.5	0.0	3.2	155.9
Tennessee	0.0	12.5	14.8	0.0	0.0	0.0	3.2	318.1	0.0	348.7
Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0	0.0	1.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	60.0	429.4	286.7	57.4	809.6	23.6	353.3	525.4	461.8	3,007.2

15 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
16 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed April 01, 2011).

Operating Reserve[17]

Credit and Charge Results

Overall Results

Table 3-49 Monthly operating reserve charges: Calendar years 2010 and 2011 (See SOM 2010, Table 3-72)

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,472,496	$50,803,869	$12,373,099	$110,095	$47,752,503	$60,235,697
Feb	$11,425,494	$14,715	$22,346,529	$33,786,738	$8,940,203	$139,287	$26,337,304	$35,416,794
Mar	$8,836,886	$122,817	$16,823,288	$25,782,991	$6,837,719	$66,032	$24,219,783	$31,123,534
Apr	$7,633,141	$93,253	$22,870,495	$30,596,889				
May	$5,127,307	$131,600	$39,144,404	$44,403,311				
Jun	$3,511,264	$33,923	$56,989,229	$60,534,415				
Jul	$4,601,788	$88,136	$63,190,853	$67,880,778				
Aug	$3,622,670	$66,535	$41,690,612	$45,379,817				
Sep	$8,433,892	$27,971	$40,637,086	$49,098,949				
Oct	$7,719,744	$1,543	$30,433,986	$38,155,273				
Nov	$6,556,715	$29,674	$20,020,310	$26,606,698				
Dec	$12,951,879	$59,954	$83,021,125	$96,032,958				
Total	$30,543,731	$187,554	$79,642,313	$110,373,599	$28,151,021	$315,414	$98,309,589	$126,776,024
Share of Annual Charges	27.7%	0.2%	72.2%	100.0%	22.2%	0.2%	77.5%	100.0%

17 See the *2010 State of the Market Report for PJM* Volume II, Section 3, "Energy Market, Part 2", Table 3-68 *Operating reserve credit and charges* and Table 3-69 *Operating reserve deviations* for details regarding operating reserve structure.

Table 3-50 Regional balancing charges allocation: January through March 2011[18] (See SOM 2010, Table 3-73)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$16,943,025 21.1%	$740,353 0.9%	$17,683,378 22.0%	$30,441,252 37.8%	$10,466,880 13.0%	$10,493,852 13.0%	$51,401,983 63.9%	$69,085,361 85.8%
East	$1,314,882 1.6%	$52,439 0.1%	$1,367,321 1.7%	$2,007,896 2.5%	$681,169 0.8%	$591,083 0.7%	$3,280,149 4.1%	$4,647,469 5.8%
West	$4,573,669 5.7%	$230,503 0.3%	$4,804,172 6.0%	$1,033,628 1.3%	$471,498 0.6%	$436,866 0.5%	$1,941,992 2.4%	$6,746,164 8.4%
Total	$22,831,577 28.4%	$1,023,294 1.3%	$23,854,871 29.6%	$33,482,776 41.6%	$11,619,547 14.4%	$11,521,801 14.3%	$56,624,124 70.4%	$80,478,995 100%

Deviations

Allocation

Table 3-51 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011 (See SOM 2010, Table 3-74)

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,795,075	3,263,461	3,190,976	16,249,511
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	2,715,163	12,721,102
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,172	2,781,147	12,758,678
Apr	7,006,983	4,668,407	2,132,045	13,807,435				
May	9,004,034	4,228,004	2,416,103	15,648,141				
Jun	10,936,989	3,964,478	3,174,230	18,075,697				
Jul	10,928,408	3,847,011	3,412,498	18,187,917				
Aug	9,747,045	3,417,328	3,188,437	16,352,810				
Sep	9,480,237	3,587,356	2,524,213	15,591,806				
Oct	7,170,712	2,913,554	2,368,303	12,452,569				
Nov	7,606,971	2,860,054	2,485,153	12,952,178				
Dec	10,069,627	4,027,236	3,513,489	17,610,352				
Total	107,168,077	49,691,893	32,634,038	189,494,008	24,501,987	8,540,017	8,687,286	41,729,290
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	58.7%	20.5%	20.8%	100.0%

18 The total charges shown in Table 3-50 do not equal the total balancing charges shown in Table 3-49 because the totals in Table 3-49 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-50 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.

Table 3-52 Regional charges determinants (MWh): January through March 2011 (See SOM 2010, Table 3-75)

	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	174,918,790	7,695,621	182,614,411	24,501,987	8,540,017	8,687,286	41,729,290	224,343,702
East	94,176,944	3,799,175	97,976,119	14,838,976	4,635,609	4,307,451	23,782,036	121,758,155
West	80,741,846	3,896,446	84,638,292	9,612,552	3,865,133	4,379,835	17,857,520	102,495,812

Table 3-53 Monthly impacts on netting deviations: January through March 2011 (See SOM 2010, Table 3-76)

Month	Demand Deviations (MWh) Old Rules	Demand Deviations (MWh) New Rules	Difference	Supply Deviations (MWh) Old Rules	Supply Deviations (MWh) New Rules	Difference	Generator Deviations (MWh) Old Rules	Generator Deviations (MWh) New Rules	Difference
Jan	8,956,331	9,795,075	838,743	3,137,527	3,263,461	125,934	3,198,301	3,191,499	(6,802)
Feb	6,694,980	7,196,554	501,574	2,738,472	2,809,384	70,912	2,729,986	2,715,190	(14,796)
Mar	7,007,409	7,510,358	502,950	2,386,345	2,467,172	80,827	2,790,461	2,783,720	(6,741)
Total	22,658,720	24,501,987	1,843,267	8,262,344	8,540,017	277,673	8,718,748	8,690,408	(28,339)

Table 3-54 Summary of impact on netting deviations: January through March 2011 (See SOM 2010, Table 3-77)

	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Total Deviations (MWh)
Old Rules (No Netting)	22,658,720	8,262,344	8,718,748	39,639,811
New Rules (Netting)	24,501,987	8,540,017	8,690,408	41,732,412
Difference	1,843,267	277,673	(28,339)	2,092,601

Balancing Operating Reserve Charge Rate

Figure 3-11 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): January through March 2011 (See SOM 2010, Figure 3-20)

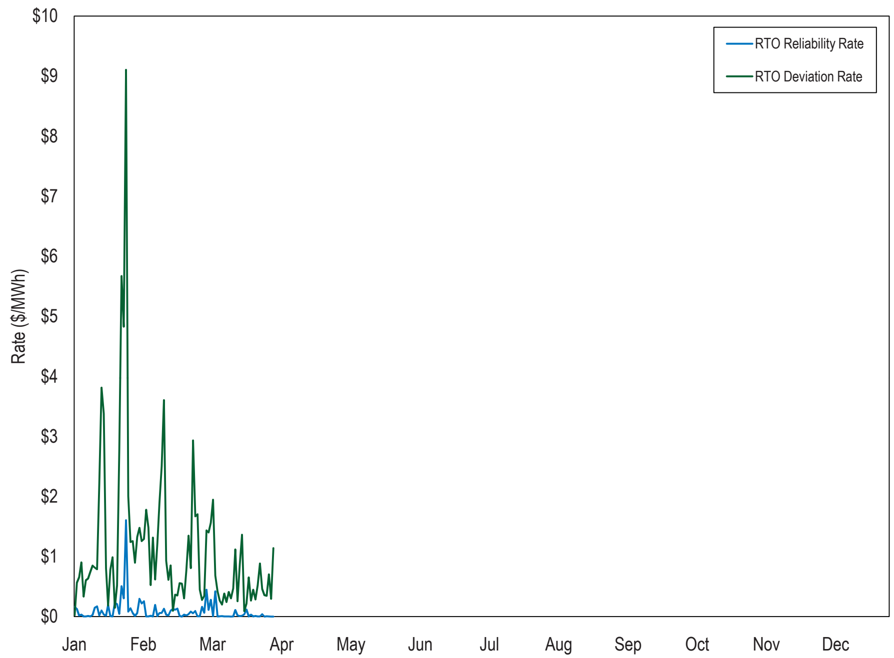


Figure 3-12 Daily regional reliability and deviation rates ($/MWh): January through March 2011 (See SOM 2010, Figure 3-21)

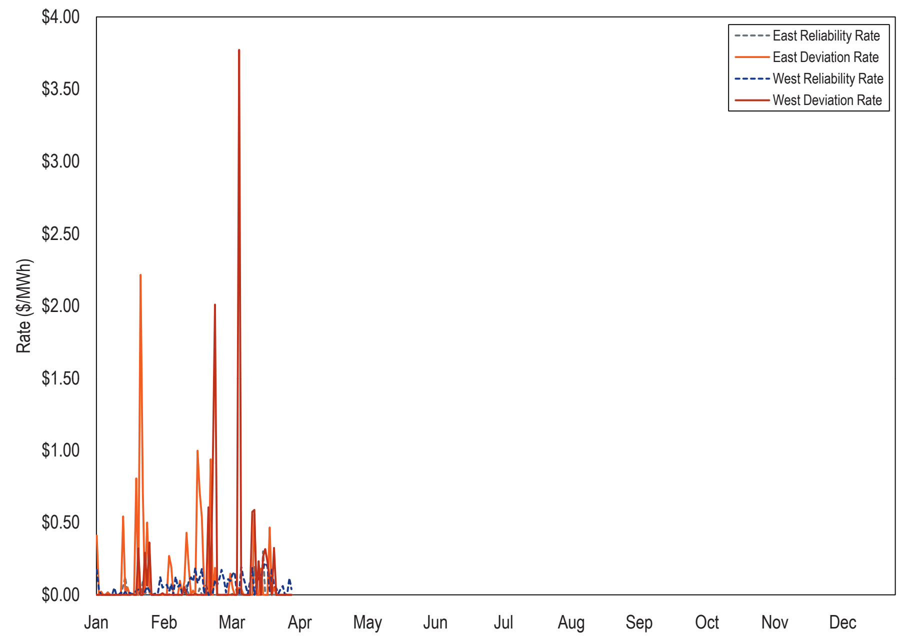


Table 3-55 Regional balancing operating reserve rates ($/MWh): January through March 2011 (See SOM 2010, Table 3-78)

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.092	1.141
East	0.000	0.129
West	0.060	0.122

Operating Reserve Credits by Category

Figure 3-13 Operating reserve credits: January through March 2011 (See SOM 2010, Figure 3-22)

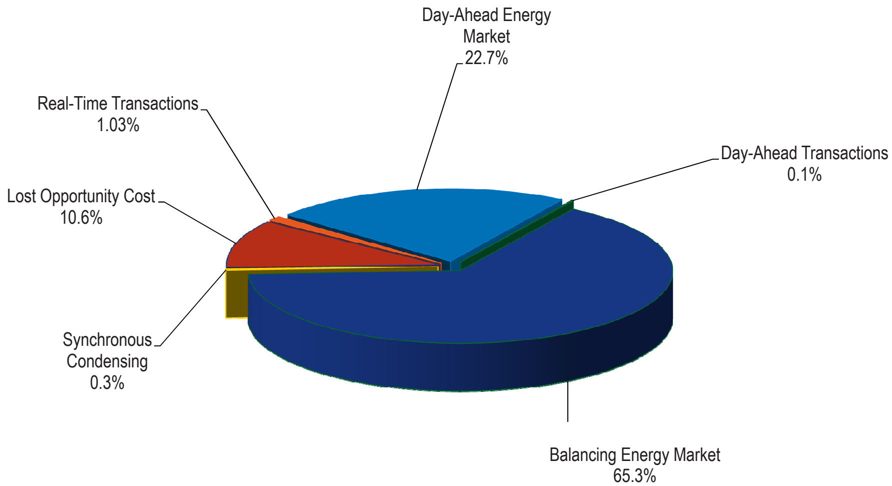


Table 3-56 Credits by month (By operating reserve market): Calendar year 2011[19] (See SOM 2010, Table 3-79)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$42,106,060	$473,317	$2,887,804	$57,950,375
Feb	$8,844,162	$96,041	$139,287	$22,787,740	$378,056	$3,171,508	$35,416,794
Mar	$6,830,696	$7,024	$66,032	$15,720,534	$421,862	$7,085,630	$30,131,777
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$28,027,469	$123,553	$315,414	$80,614,333	$1,273,235	$13,144,943	$123,498,946
Share of Credits	22.7%	0.1%	0.3%	65.3%	1.0%	10.6%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-57 Credits by unit types (By operating reserve market): January through March 2011 (See SOM 2010, Table 3-80)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	32.7%	0.0%	66.3%	0.9%	$54,660,271
Combustion Turbine	0.8%	0.9%	79.1%	19.2%	$34,123,235
Diesel	0.0%	0.0%	77.2%	22.8%	$75,907
Hydro	0.0%	0.0%	100.0%	0.0%	$731,094
Landfill	0.0%	0.0%	0.0%	100.0%	$5,299,228
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	36.6%	0.0%	60.6%	2.9%	$26,976,468
Wind Farm	0.0%	0.0%	100.0%	0.0%	$204,398

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

Table 3-58 Credits by operating reserve market (By unit type): January through March 2011 (See SOM 2010, Table 3-81)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	63.8%	0.0%	45.0%	3.9%
Combustion Turbine	1.0%	100.0%	33.5%	49.8%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.9%	0.0%
Landfill	0.0%	0.0%	0.0%	40.3%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	35.2%	0.0%	20.3%	5.9%
Wind Farm	0.0%	0.0%	0.3%	0.0%
Total	$28,027,469	$315,414	$80,584,348	$13,143,370

Economic and Noneconomic Generation

Table 3-59 Economic vs. noneconomic hours: January through March 2011 (See SOM 2010, Table 3-82)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	6,302	60.4%	4,135	39.6%	10,437
Combustion Turbine	1,095	23.3%	3,602	76.7%	4,697
Diesel	31	16.4%	158	83.6%	189
Steam	13,702	84.7%	2,467	15.3%	16,169

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-60 Regional balancing operating reserve credits: January through March 2011 (See SOM 2010, Table 3-86)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$17,683,378	$51,401,983	$69,085,361
East	$1,367,321	$3,280,149	$4,647,469
West	$4,769,142	$1,941,992	$6,711,134
Total	$23,819,840	$56,624,124	$80,443,964

Table 3-61 Total deviations: January through March 2011 (See SOM 2010, Table 3-87)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	24,501,987	8,540,017	8,687,286	41,729,290

Table 3-62 Charge allocation under old operating reserve construct: January through March 2011 (See SOM 2010, Table 3-88)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	24,501,987	8,540,017	8,687,286	41,729,290
Balancing Rate ($/MWh)	1.928	1.928	1.928	1.928
Charges ($)	$47,233,896	$16,463,084	$16,746,984	$80,443,964

Table 3-63 Actual regional credits, charges, rates and charge allocation (MWh): January through March 2011 (See SOM 2010, Table 3-89)

	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	$17,683,378	182,614,411	0.097	$17,683,378	$51,401,983	41,729,290	1.232	$51,401,983	$69,085,361
East	$1,367,321	97,976,119	0.014	$1,367,321	$3,280,149	23,782,036	0.138	$3,280,149	$4,647,469
West	$4,769,142	83,735,322	0.057	$4,769,142	$1,941,992	17,720,520	0.110	$1,941,992	$6,711,134
Total	$23,819,840	182,614,411	NA	$23,819,840	$56,624,124	41,729,290	NA	$56,624,124	$80,443,964

Table 3-64 Difference in total operating reserve charges between old rules and new rules: January through March 2011 (See SOM 2010, Table 3-90)

	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	$47,233,896	$16,463,084	$16,746,984	$80,443,964
Charges (Current)	$22,797,761	$1,022,080	$23,819,840	$33,482,776	$11,619,547	$11,521,801	$56,624,124
Difference	$22,797,761	$1,022,080	$23,819,840	($13,751,120)	($4,843,538)	($5,225,183)	($23,819,840)

Impact on Decrement Bids and Incremental Offers

Table 3-65 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through March, 2010 and 2011 (See SOM 2010, Table 3-91)

	2010				2011			
Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	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	6,054,214	8,284,810	1,548,295	3,162,842
Feb	8,323,844	11,828,781	2,004,162	2,234,045	5,732,202	7,440,032	1,376,811	2,271,323
Mar	8,032,429	11,159,303	2,150,898	2,594,826	5,372,006	7,753,370	1,152,806	2,548,787
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	2,676,901				
Sep	8,188,967	11,532,284	2,103,152	3,105,498				
Oct	7,777,616	10,423,935	1,564,871	2,163,717				
Nov	8,027,852	11,041,950	1,408,786	2,467,942				
Dec	9,416,187	12,320,592	1,920,956	3,451,929				
Total	98,488,750	140,097,307	23,609,817	35,212,727	17,158,422	23,478,211	4,077,912	7,982,952

Table 3-66 Comparison of balancing operating reserve charges to virtual bids: January through March, 2010 and 2011 (See SOM 2010, Table 3-92)

	2010			2011		
Month	Charges Under Old Rules	Charges Under Current Rules	Difference	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)	$10,130,258	$13,855,712	($3,725,454)
Feb	$5,319,874	$3,936,420	($1,383,454)	$5,758,334	$7,474,212	($1,715,879)
Mar	$4,797,076	$3,468,829	($1,328,248)	$4,945,666	$6,666,882	($1,721,216)
Apr	$6,480,725	$5,301,308	($1,179,417)			
May	$13,658,944	$10,158,307	($3,500,637)			
Jun	$18,021,960	$10,673,612	($7,348,348)			
Jul	$17,068,724	$14,327,987	($2,740,737)			
Aug	$9,394,993	$7,575,980	($1,819,013)			
Sep	$13,065,704	$10,820,010	($2,245,694)			
Oct	$9,019,721	$6,456,368	($2,563,353)			
Nov	$5,817,780	$3,925,450	($1,892,330)			
Dec	$17,570,579	$19,884,462	$2,313,884			
Total	$132,741,464	$106,719,600	($26,021,864)	$20,834,257	$27,996,806	($7,162,549)

Table 3-67 Summary of impact on virtual bids under balancing operating reserve allocation: January through March, 2010 and 2011 (See SOM 2010, Table 3-93)

	Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Under Current Rules ($/MWh)	Balancing Rate Under Old Rules ($/MWh)	Charges Under Current Rules	Charges Under Old Rules	Differerence
2010	RTO	6,618,912	8,280,918	14,899,830	0.942	1.383	$15,650,032	$22,371,028	($6,720,997)
	East	4,481,203	4,848,963	9,330,165	0.118	0.000	$1,097,057	$0	$1,097,057
	West	2,113,208	3,385,979	5,499,187	0.119	0.000	$603,725	$0	$603,725
2011	RTO	4,077,912	7,982,952	12,060,863	1.515	2.194	$19,384,060	$27,996,806	($8,612,746)
	East	2,201,838	3,753,224	5,955,062	0.135	0.000	$802,288	$0	$802,288
	West	1,836,798	4,179,269	6,016,067	0.113	0.000	$647,909	$0	$647,909

Segmented Make Whole Payments

Table 3-68 Impact of segmented make whole payments: January through March 2011 (See SOM 2010, Table 3-94)

	2010			2011		
Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
Jan	$32,982,105	$33,924,489	$942,385	$40,721,858	$41,949,204	$1,227,346
Feb	$17,321,317	$17,609,133	$287,815	$21,621,511	$22,774,422	$1,152,911
Mar	$13,458,120	$13,672,172	$214,052	$14,872,573	$15,695,526	$822,954
Apr	$16,441,644	$17,036,058	$594,414			
May	$21,854,306	$23,455,721	$1,601,415			
Jun	$36,297,521	$38,885,349	$2,587,828			
Jul	$32,251,623	$37,053,630	$4,802,007			
Aug	$21,867,024	$24,335,171	$2,468,147			
Sep	$24,293,196	$25,686,790	$1,393,593			
Oct	$21,839,101	$22,478,455	$639,354			
Nov	$15,795,391	$16,238,383	$442,991			
Dec	$49,180,164	$51,293,810	$2,113,646			
Total	$303,581,512	$321,669,160	$18,087,648	$77,215,942	$80,419,153	$3,203,211

Table 3-69 Impact of segmented make whole payments (By unit type): January through March 2011 (See SOM 2010, Table 3-95)

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	242	$4,685	$8,177	$3,492	$1,133,762	$1,978,773	$845,011
Medium Frame Combustion Turbine (30 - 65 MW)	434	$2,255	$2,802	$547	$978,722	$1,215,955	$237,233
Large Frame Combustion Turbine (135 - 180 MW)	24	$17,622	$24,943	$7,321	$422,925	$598,631	$175,705
Petroleum/Gas Steam (Post-1985)	13	$5,227	$11,677	$6,450	$67,946	$151,798	$83,852
Sub-Critical Coal	98	$51	$618	$567	$5,023	$60,591	$55,569
Medium-Large Frame Combustion Turbine (65 - 125 MW)	60	$3,960	$4,745	$786	$237,571	$284,716	$47,145
Small Frame Combustion Turbine (0 - 29 MW)	34	$3,177	$3,361	$183	$108,025	$114,264	$6,239
Diesel	1	$0	$1,210	$1,210	$0	$1,210	$1,210

Table 3-70 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through March 2011 (See SOM 2010, Table 3-96)

Unit Type	Share of Increase
Combined-Cycle	14.2%
Steam	4.8%
Combustion Turbines	73.8%
Diesel	7.1%

Unit Operating Parameters[20]

Table 3-71 Units receiving credits from a parameter limited schedule: January through March 2011 (See SOM 2010, Table 3-98)

Unit Type	Number of Units	Observations
Combined-Cycle	1	1
Large Frame Combustion Turbine (135 - 180 MW)	2	3
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	33
Petroleum/Gas Steam (Pre-1985)	1	2
Sub-Critical Coal	13	76

Issues in Operating Reserves

Concentration of Operating Reserve Credits

Table 3-72 Unit operating reserve credits for units (By zone): January through March 2011 (See SOM 2010, Table 3-100)

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	$81,262	$0	$1,027,344	$430,881	$1,539,486	1.3%
AEP	$518,737	$0	$7,863,677	$269,853	$8,652,267	7.2%
AP	$503,257	$0	$2,686,329	$968,560	$4,158,146	3.5%
BGE	$3,162,984	$0	$1,914,686	$11,195	$5,088,865	4.2%
ComEd	$130,850	$0	$879,129	$549,700	$1,559,678	1.3%
DAY	$1,568	$0	$196,770	$5,025	$203,363	0.2%
Dominion	$818,887	$0	$12,941,842	$8,647,410	$22,408,140	18.6%
DPL	$409,631	$0	$2,926,557	$281,793	$3,617,981	3.0%
DLCO	$145,077	$0	$851,816	$0	$996,893	0.8%
JCPL	$1,227,517	$0	$3,439,615	$50,489	$4,717,621	3.9%
Met-Ed	$66,745	$0	$408,577	$313	$475,635	0.4%
PECO	$350,877	$4,692	$1,339,968	$217,677	$1,913,213	1.6%
PENELEC	$0	$0	$522,328	$245,087	$767,415	0.6%
Pepco	$1,175,318	$0	$5,029,368	$599,501	$6,804,187	5.7%
PPL	$49,265	$0	$3,322,132	$488,089	$3,859,486	3.2%
PSEG	$19,153,341	$310,354	$33,908,994	$222,480	$53,595,169	44.5%
External	$0	$0	$0	$0	$0	0.0%
Total	$27,795,315	$315,046	$79,259,131	$12,988,053	$120,357,545	100.0%

20 See the *2010 State of the Market Report for PJM*, Volume 2, Section 3, "Energy Market, Part 2," Table 3-97 *Unit Parameter Limited Schedule Matrix* for details regarding default unit operating parameters.

Table 3-73 Top 10 units and organizations receiving total operating reserve credits: January through March 2011 (See SOM 2010, Table 3-101)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$18,619,098	18.1%	18.1%	$49,165,106	47.9%	47.9%
2	$15,086,428	14.7%	32.8%	$8,141,922	7.9%	55.8%
3	$5,101,609	5.0%	37.8%	$6,291,698	6.1%	61.9%
4	$3,172,914	3.1%	40.9%	$5,679,306	5.5%	67.5%
5	$2,300,662	2.2%	43.1%	$4,714,947	4.6%	72.1%
6	$1,842,375	1.8%	44.9%	$3,933,095	3.8%	75.9%
7	$1,668,308	1.6%	46.5%	$3,172,914	3.1%	79.0%
8	$1,452,456	1.4%	48.0%	$3,020,195	2.9%	81.9%
9	$1,225,256	1.2%	49.2%	$2,263,372	2.2%	84.1%
10	$1,198,615	1.2%	50.3%	$1,381,434	1.3%	85.5%

Table 3-74 Top 10 units and organizations receiving day-ahead generator credits: January through March 2011 (See SOM 2010, Table 3-102)

	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	$9,030,534	29.7%	29.7%	$19,975,372	65.7%	65.7%
2	$4,481,756	14.7%	44.4%	$1,840,078	6.1%	71.7%
3	$3,300,358	10.9%	55.3%	$1,125,078	3.7%	75.4%
4	$1,840,078	6.1%	61.3%	$1,088,419	3.6%	79.0%
5	$1,593,833	5.2%	66.6%	$970,016	3.2%	82.2%
6	$1,086,840	3.6%	70.1%	$872,676	2.9%	85.1%
7	$963,905	3.2%	73.3%	$751,554	2.5%	87.5%
8	$585,511	1.9%	75.2%	$654,220	2.2%	89.7%
9	$348,635	1.1%	76.4%	$573,047	1.9%	91.6%
10	$323,106	1.1%	77.4%	$522,597	1.7%	93.3%

Table 3-75 Top 10 units and organizations receiving synchronous condensing credits: January through March 2011 (See SOM 2010, Table 3-103)

	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	$20,686	11.0%	11.0%	$156,309	83.3%	83.3%
2	$14,462	7.7%	18.7%	$13,768	7.3%	90.7%
3	$12,753	6.8%	25.5%	$8,905	4.7%	95.4%
4	$11,874	6.3%	31.9%	$6,477	3.5%	98.9%
5	$10,763	5.7%	37.6%	$2,095	1.1%	100.0%
6	$10,748	5.7%	43.3%			
7	$8,118	4.3%	47.7%			
8	$7,821	4.2%	51.8%			
9	$7,264	3.9%	55.7%			
10	$7,182	3.8%	59.5%			

Table 3-76 Top 10 units and organizations receiving balancing generator credits: January through March 2011 (See SOM 2010, Table 3-104)

	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	$14,137,342	21.8%	21.8%	$28,999,449	44.7%	44.7%
2	$6,055,299	9.3%	31.2%	$7,136,836	11.0%	55.7%
3	$1,801,251	2.8%	33.9%	$5,328,108	8.2%	64.0%
4	$1,598,443	2.5%	36.4%	$5,217,078	8.0%	72.0%
5	$1,441,118	2.2%	38.6%	$2,827,369	4.4%	76.4%
6	$1,332,836	2.1%	40.7%	$1,982,601	3.1%	79.4%
7	$1,198,615	1.8%	42.5%	$1,845,025	2.8%	82.3%
8	$1,181,333	1.8%	44.3%	$1,332,836	2.1%	84.3%
9	$930,953	1.4%	45.8%	$1,171,163	1.8%	86.1%
10	$904,293	1.4%	47.2%	$1,158,356	1.8%	87.9%

Table 3-77 Top 10 units and organizations receiving lost opportunity cost credits: January through March 2011 (See SOM 2010, Table 3-105)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$886,383	12.2%	12.2%	$4,713,550	65.1%	65.1%
2	$682,772	9.4%	21.7%	$762,534	10.5%	75.6%
3	$635,812	8.8%	30.4%	$391,996	5.4%	81.0%
4	$591,740	8.2%	38.6%	$390,543	5.4%	86.4%
5	$544,001	7.5%	46.1%	$208,377	2.9%	89.3%
6	$522,921	7.2%	53.3%	$132,410	1.8%	91.1%
7	$427,283	5.9%	59.2%	$70,289	1.0%	92.1%
8	$335,251	4.6%	63.9%	$65,973	0.9%	93.0%
9	$241,343	3.3%	67.2%	$61,475	0.8%	93.8%
10	$216,586	3.0%	70.2%	$57,968	0.8%	94.6%

Recommendations

Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers are based on historical cost-based offers within one standard deviation of the mean since November 2007.

Table 3-78 is based on calculating notification and startup times independently, then adding together. Table 3-79 is based on adding notification and startup times together first, then calculating distribution. All data are based on historical cost-based offers within one standard deviation of the mean since November 2007.

Table 3-78 Cold notification and cold startup hours (By percentile): Since November 2007 (New table)

	Cold Notification Time			Cold Startup Time			CS + CN		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	4	8.5	18	12.5	14	18	16.5	22.5	36
Petroleum/Gas Steam (Post-1985)	1	1	2	6	12	14	7	13	16
Combined-Cycle	2	5	7	5	6.2	8	7	11.2	15
Sub-Critical Coal	2	2	4	15	16	20	17	18	24
Super-Critical Coal	2	2	8	19	20	22	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	0.25	1	2	0.5	0.5	0.8	0.75	1.5	2.8
Medium Frame Combustion Turbine (30 - 65 MW)	0.2	0.3	1.4	0.3	0.5	0.5	0.5	0.8	1.9
Medium-Large Frame Combustion Turbine (65 - 135 MW)	1	2	2	0.5	0.7	1	1.5	2.7	3
Large Frame Combustion Turbine (135 - 180 MW)	2	5	6	0.5	0.7	1	2.5	5.7	7

Table 3-79 Time-To-Start hours (By percentile): Since November 2007 (New table)

	All Months			Peak Months			Off-Peak Months		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	18	20	32	18	20	30	17	19	32
Petroleum/Gas Steam (Post-1985)	9	13	14	9	13	14	9	13	14
Combined-Cycle	9	11	14	8.5	10	13.5	9	11	14
Sub-Critical Coal	16.5	18	22	16.5	18	22.5	16	18	22
Super-Critical Coal	21	22	30	21	22	30	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	1	1.5	2.2	1	1.5	2.2	1	1.5	2.2
Medium Frame Combustion Turbine (30 - 65 MW)	0.5	0.8	1.7	0.5	0.7	1.7	0.5	1	2
Medium-Large Frame Combustion Turbine (65 - 135 MW)	2	2	3.3	2	2	3.3	2	2.3	3.4
Large Frame Combustion Turbine (135 - 180 MW)	3	5	6.6	2.5	4.3	6.6	4	5	6.8

Parameter Limited Schedules

Currently, parameter limited schedules are only enforced for cost-based schedules, except for emergencies, permitting the use of price-based schedule parameters as a possible method to exercise market power. For example, a unit may extend a minimum down time to avoid being turned off when not economic, which will increase operating reserve credits to the unit and operating reserve charges paid by other participants. The MMU recommends the enforcement of parameter limit for both cost-based and market-based schedules.