# SECTION 3 – ENERGY MARKET, PART 2

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

## *Overview*

### Net Revenue

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

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

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

  Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives. While the 2009 net revenue using PJM real-time average locational marginal prices was $23,845 per MW-year for a CT, the zonal maximum net revenue was $42,549 in the Pepco Control Zone and the minimum was $20,762 in the ComEd Control Zone.[1] While the PJM

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

average net revenue in 2009 was $39,673 per MW-year for a CC, the zonal maximum net revenue was $67,829 in the Pepco Control Zone and the minimum was $34,516 in the ComEd Control Zone. While the PJM average net revenue in 2008 was $53,477 per MW-year for a CP, the zonal maximum net revenue was $105,845 in the Pepco Control Zone and the minimum was $50,938 in the DAY Control Zone.

## Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through July 1, 2009, PJM installed capacity resources rose slightly from 164,899 MW on January 1 to 167,454 MW on June 1.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at June 1, 2009, 40.7 percent was coal; 29.2 percent was natural gas; 18.3 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During January through June 2009, coal provided 51.3 percent, nuclear 36.1 percent, gas 8.6 percent, oil 0.2 percent, hydroelectric 2.0 percent, solid waste 0.8 percent and wind 0.8 percent of total generation.

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

## Scarcity

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

- **Scarcity.** A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

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

  The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

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

- **Modifications to Scarcity Pricing.** While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, PJM's scarcity pricing rules need refinement. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant.


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

Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. Implemented as scarcity region specific operating reserve constraints in the security constrained dispatch, the severity of scarcity event should be reflected in a set of increasing, administrative penalty factors.

If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event. Properly set, the penalty factors would increase prices on the system to provide a locational pricing signal reflecting the severity of the shortage. This approach also eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events. Keeping offers consistent during the event would have the added benefit of avoiding the operational issues involved with sudden changes in the economic dispatch order before, during and after a scarcity event.

## Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2009.** The level of operating reserve credits and corresponding charges decreased in the months of January through June by 26.2 percent compared to the months of January through June 2008. This was the result of a large decrease in the amount of balancing operating reserve credits. Day-ahead credits increased significantly from the first six months of 2008, while synchronous condensing credits were slightly higher.

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

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

## 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

2 126 FERC ¶61,251 (2009).

construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

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

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

While net revenue in PJM has been almost sufficient to cover the costs of new peaking units in some years and was sufficient to cover the costs of a new coal plant in 2005 and close to covering those costs in 2006 in some eastern zones, net revenue prior to the RPM construct was generally below the level required to cover the full costs of new generation investment for several years and below that level on average for all unit types for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM markets. However, it is also the case that there have been some units in PJM, needed for reliability, with revenues less than annual going-forward costs, which, if it persists, is a signal to retire. This suggests that market price signals and reliability needs have not been fully synchronized.

The historical level of net revenues in PJM markets is 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 value the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

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

The combination of locational Energy Market and locational Capacity Market signals in 2007 represented a significant change from market performance over prior years. The combined locational prices clearly signaled a need for and an incentive for investment in eastern zones where there is a demonstrated need for new capacity, although the results vary by technology. In 2007, net revenues exceeded the costs of all technologies in the BGE and Pepco Control Zones and net revenues exceeded the costs of CC technology in seven eastern control zones.

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

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore


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

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

## Net Revenue

### Capacity Market Net Revenue

*Table 3-1 2008 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through June 30, 2009 (See 2008 SOM, Table 3-3)*

| | Delivery Year 2008/2009 | | | Delivery Year 2009/2010 | | | RPM Revenue 2009 |
|---|---|---|---|---|---|---|---|
| Zone | LDA | $/MW-Day | $/MW in 2009 | LDA | $/MW-Day | $/MW in 2009 | (Jan-Jun) |
| AECO | EMAAC | $148.80 | $22,469 | MAAC+APS | $191.32 | $5,740 | $28,208 |
| AEP | RTO | $111.92 | $16,900 | RTO | $102.04 | $3,061 | $19,961 |
| AP | RTO | $111.92 | $16,900 | MAAC+APS | $191.32 | $5,740 | $22,640 |
| BGE | SWMAAC | $210.11 | $31,727 | SWMAAC | $237.33 | $7,120 | $38,847 |
| ComEd | RTO | $111.92 | $16,900 | RTO | $102.04 | $3,061 | $19,961 |
| DAY | RTO | $111.92 | $16,900 | RTO | $102.04 | $3,061 | $19,961 |
| DLCO | RTO | $111.92 | $16,900 | RTO | $102.04 | $3,061 | $19,961 |
| Dominion | RTO | $111.92 | $16,900 | RTO | $102.04 | $3,061 | $19,961 |
| DPL | EMAAC | $148.80 | $22,469 | MAAC+APS | $191.32 | $5,740 | $28,208 |
| JCPL | EMAAC | $148.80 | $22,469 | MAAC+APS | $191.32 | $5,740 | $28,208 |
| Met-Ed | RTO | $111.92 | $16,900 | MAAC+APS | $191.32 | $5,740 | $22,640 |
| PECO | EMAAC | $148.80 | $22,469 | MAAC+APS | $191.32 | $5,740 | $28,208 |
| PENELEC | RTO | $111.92 | $16,900 | MAAC+APS | $191.32 | $5,740 | $22,640 |
| Pepco | SWMAAC | $210.11 | $31,727 | SWMAAC | $237.33 | $7,120 | $38,847 |
| PPL | RTO | $111.92 | $16,900 | MAAC+APS | $191.32 | $5,740 | $22,640 |
| PSEG | EMAAC | $148.80 | $22,469 | MAAC+APS | $191.32 | $5,740 | $28,208 |
| RECO | EMAAC | $148.80 | $22,469 | MAAC+APS | $191.32 | $5,740 | $28,208 |
| PJM | N/A | $124.58 | $18,812 | N/A | $138.46 | $4,154 | $22,965 |

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

| Zone | 2008 (Jan- Jun) | 2009 (Jan-Jun) | Percent Change |
|---|---|---|---|
| AECO | $34,510 | $28,208 | (18%) |
| AEP | $9,559 | $19,961 | 109% |
| AP | $9,559 | $22,640 | 137% |
| BGE | $34,961 | $38,847 | 11% |
| ComEd | $9,559 | $19,961 | 109% |
| DAY | $9,559 | $19,961 | 109% |
| DLCO | $9,559 | $19,961 | 109% |
| Dominion | $9,559 | $19,961 | 109% |
| DPL | $34,510 | $28,208 | (18%) |
| JCPL | $34,510 | $28,208 | (18%) |
| Met-Ed | $9,559 | $22,640 | 137% |
| PECO | $34,510 | $28,208 | (18%) |
| PENELEC | $9,559 | $22,640 | 137% |
| Pepco | $34,961 | $38,847 | 11% |
| PPL | $9,559 | $22,640 | 137% |
| PSEG | $34,510 | $28,208 | (18%) |
| RECO | $34,510 | $28,208 | (18%) |
| PJM | $17,127 | $22,965 | 34% |

## New Entrant Net Revenues

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

| | 2008 (Jan-Jun) | 2009 (Jan-Jun) | Percent Change |
|---|---|---|---|
| Natural Gas | $11.31 | $5.28 | (53%) |
| Low Sulfur Coal | $4.18 | $3.38 | (19%) |

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

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $29,200 | $4,953 | (83%) |
| AEP | $2,685 | $2,537 | (6%) |
| AP | $13,072 | $8,495 | (35%) |
| BGE | $22,578 | $7,102 | (69%) |
| ComEd | $1,812 | $1,774 | (2%) |
| DAY | $2,891 | $2,042 | (29%) |
| DLCO | $2,156 | $1,904 | (12%) |
| Dominion | $17,205 | $7,247 | (58%) |
| DPL | $15,969 | $6,055 | (62%) |
| JCPL | $20,048 | $5,639 | (72%) |
| Met-Ed | $11,875 | $4,829 | (59%) |
| PECO | $11,750 | $4,211 | (64%) |
| PENELEC | $2,868 | $1,519 | (47%) |
| Pepco | $23,816 | $6,731 | (72%) |
| PPL | $10,326 | $4,063 | (61%) |
| PSEG | $14,290 | $5,043 | (65%) |
| RECO | $11,203 | $3,382 | (70%) |
| PJM | $5,288 | $2,180 | (59%) |


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*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 June 2008 and 2009 (See 2008 SOM, Table 3-7)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $70,898 | $26,600 | (62%) |
| AEP | $13,976 | $16,343 | 17% |
| AP | $37,100 | $33,170 | (11%) |
| BGE | $61,579 | $28,702 | (53%) |
| ComEd | $12,325 | $13,633 | 11% |
| DAY | $15,397 | $16,129 | 5% |
| DLCO | $12,514 | $14,622 | 17% |
| Dominion | $50,067 | $31,057 | (38%) |
| DPL | $52,847 | $28,171 | (47%) |
| JCPL | $68,255 | $27,791 | (59%) |
| Met-Ed | $46,588 | $24,008 | (48%) |
| PECO | $46,320 | $23,066 | (50%) |
| PENELEC | $21,162 | $14,611 | (31%) |
| Pepco | $61,553 | $27,220 | (56%) |
| PPL | $44,132 | $22,312 | (49%) |
| PSEG | $59,692 | $29,654 | (50%) |
| RECO | $50,745 | $24,012 | (53%) |
| PJM | $25,775 | $15,888 | (38%) |

*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 June 2008 and 2009 (See 2008 SOM, Table 3-7)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $202,796 | $67,460 | (67%) |
| AEP | $100,331 | $42,122 | (58%) |
| AP | $159,616 | $69,765 | (56%) |
| BGE | $188,046 | $61,089 | (68%) |
| ComEd | $126,266 | $58,761 | (53%) |
| DAY | $90,399 | $31,359 | (65%) |
| DLCO | $91,276 | $45,033 | (51%) |
| Dominion | $168,317 | $62,911 | (63%) |
| DPL | $192,769 | $55,603 | (71%) |
| JCPL | $206,426 | $66,538 | (68%) |
| Met-Ed | $177,570 | $64,039 | (64%) |
| PECO | $177,333 | $62,327 | (65%) |
| PENELEC | $154,631 | $66,369 | (57%) |
| Pepco | $197,381 | $69,239 | (65%) |
| PPL | $180,403 | $67,043 | (63%) |
| PSEG | $165,925 | $55,348 | (67%) |
| RECO | $201,345 | $64,013 | (68%) |
| PJM | $119,207 | $31,711 | (73%) |

## New Entrant Combustion Turbine

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

| | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| Energy | $5,288 | $2,180 | (59%) |
| Capacity | $15,263 | $20,466 | 34% |
| Synchronized | $0 | $0 | 0% |
| Regulation | $0 | $0 | 0% |
| Reactive | $1,199 | $1,199 | 0% |
| Total | $21,750 | $23,845 | 10% |

*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 June 2008 and 2009 (See 2008 SOM, Table 3-11)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $61,153 | $31,291 | (49%) |
| AEP | $12,403 | $21,525 | 74% |
| AP | $22,790 | $29,870 | 31% |
| BGE | $54,934 | $42,919 | (22%) |
| ComEd | $11,530 | $20,762 | 80% |
| DAY | $12,609 | $21,029 | 67% |
| DLCO | $11,874 | $20,892 | 76% |
| Dominion | $26,923 | $26,235 | (3%) |
| DPL | $47,922 | $32,392 | (32%) |
| JCPL | $52,002 | $31,977 | (39%) |
| Met-Ed | $21,593 | $26,204 | 21% |
| PECO | $43,704 | $30,549 | (30%) |
| PENELEC | $12,586 | $22,894 | 82% |
| Pepco | $56,172 | $42,549 | (24%) |
| PPL | $20,044 | $25,438 | 27% |
| PSEG | $46,243 | $31,380 | (32%) |
| RECO | $43,156 | $29,720 | (31%) |
| PJM | $21,750 | $23,845 | 10% |

## New Entrant Combined Cycle

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

| | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| Energy | $25,775 | $15,888 | (38%) |
| Capacity | $16,546 | $22,186 | 34% |
| Synchronized | $0 | $0 | 0% |
| Regulation | $0 | $0 | 0% |
| Reactive | $1,599 | $1,599 | 0% |
| Total | $43,920 | $39,673 | (10%) |

*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 June 2008 and 2009 (See 2008 SOM, Table 3-13)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $105,836 | $55,451 | (48%) |
| AEP | $24,810 | $37,226 | 50% |
| AP | $47,933 | $56,641 | 18% |
| BGE | $96,953 | $67,829 | (30%) |
| ComEd | $23,159 | $34,516 | 49% |
| DAY | $26,231 | $37,012 | 41% |
| DLCO | $23,348 | $35,505 | 52% |
| Dominion | $60,901 | $51,940 | (15%) |
| DPL | $87,785 | $57,021 | (35%) |
| JCPL | $103,193 | $56,641 | (45%) |
| Met-Ed | $57,422 | $47,478 | (17%) |
| PECO | $81,258 | $51,917 | (36%) |
| PENELEC | $31,996 | $38,081 | 19% |
| Pepco | $96,927 | $66,347 | (32%) |
| PPL | $54,966 | $45,782 | (17%) |
| PSEG | $94,630 | $58,504 | (38%) |
| RECO | $85,683 | $52,862 | (38%) |
| PJM | $43,920 | $39,673 | (10%) |

## New Entrant Coal Plant

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

| | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| Energy | $119,207 | $31,711 | (73%) |
| Capacity | $15,441 | $20,705 | 34% |
| Synchronized | $0 | $0 | 0% |
| Regulation | $352 | $170 | (52%) |
| Reactive | $892 | $892 | 0% |
| Total | $135,891 | $53,477 | (61%) |


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*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 June 2008 and 2009 (See 2008 SOM, Table 3-15)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $235,299 | $94,506 | (60%) |
| AEP | $110,315 | $61,750 | (44%) |
| AP | $169,716 | $91,846 | (46%) |
| BGE | $220,952 | $97,301 | (56%) |
| ComEd | $136,532 | $78,327 | (43%) |
| DAY | $100,312 | $50,930 | (49%) |
| DLCO | $101,420 | $64,726 | (36%) |
| Dominion | $178,372 | $82,447 | (54%) |
| DPL | $225,296 | $82,106 | (64%) |
| JCPL | $238,863 | $93,273 | (61%) |
| Met-Ed | $187,554 | $86,012 | (54%) |
| PECO | $209,834 | $89,349 | (57%) |
| PENELEC | $164,723 | $88,455 | (46%) |
| Pepco | $230,335 | $105,845 | (54%) |
| PPL | $190,393 | $89,089 | (53%) |
| PSEG | $198,378 | $81,853 | (59%) |
| RECO | $233,873 | $90,697 | (61%) |
| PJM | $135,891 | $53,477 | (61%) |

## 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 June 2008 and 2009 (See 2008 SOM, Table 3-16)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $8,172 | $1,578 | (81%) |
| AEP | $599 | $880 | 47% |
| AP | $5,416 | $3,765 | (30%) |
| BGE | $12,230 | $2,840 | (77%) |
| ComEd | $184 | $343 | 87% |
| DAY | $366 | $392 | 7% |
| DLCO | $345 | $389 | 13% |
| Dominion | $8,017 | $4,000 | (50%) |
| DPL | $7,259 | $1,924 | (73%) |
| JCPL | $6,068 | $1,380 | (77%) |
| Met-Ed | $5,013 | $1,185 | (76%) |
| PECO | $5,199 | $1,251 | (76%) |
| PENELEC | $1,923 | $511 | (73%) |
| Pepco | $14,070 | $2,680 | (81%) |
| PPL | $4,207 | $1,069 | (75%) |
| PSEG | $5,513 | $1,289 | (77%) |
| RECO | $136,356 | $836 | (99%) |
| PJM | $2,661 | $508 | (81%) |

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*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 June 2008 and 2009 (See 2008 SOM, Table 3-17)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $45,811 | $27,935 | (39%) |
| AEP | $9,589 | $15,384 | 60% |
| AP | $29,254 | $30,339 | 4% |
| BGE | $51,634 | $29,531 | (43%) |
| ComEd | $8,838 | $10,207 | 15% |
| DAY | $9,533 | $13,450 | 41% |
| DLCO | $6,524 | $11,897 | 82% |
| Dominion | $41,456 | $32,751 | (21%) |
| DPL | $39,396 | $29,055 | (26%) |
| JCPL | $57,161 | $28,666 | (50%) |
| Met-Ed | $36,345 | $24,096 | (34%) |
| PECO | $34,301 | $25,170 | (27%) |
| PENELEC | $17,660 | $13,509 | (24%) |
| Pepco | $54,854 | $28,008 | (49%) |
| PPL | $33,424 | $22,812 | (32%) |
| PSEG | $50,130 | $30,979 | (38%) |
| RECO | $239,769 | $26,865 | (89%) |
| PJM | $17,662 | $13,598 | (23%) |

*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 June 2008 and 2009 (See 2008 SOM, Table 3-18)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | Percent Change |
|---|---|---|---|
| AECO | $196,782 | $70,556 | (64%) |
| AEP | $98,742 | $40,801 | (59%) |
| AP | $158,653 | $67,078 | (58%) |
| BGE | $192,227 | $63,445 | (67%) |
| ComEd | $129,447 | $58,235 | (55%) |
| DAY | $86,515 | $28,208 | (67%) |
| DLCO | $96,995 | $41,808 | (57%) |
| Dominion | $170,613 | $65,272 | (62%) |
| DPL | $194,963 | $56,656 | (71%) |
| JCPL | $209,636 | $68,608 | (67%) |
| Met-Ed | $182,130 | $66,001 | (64%) |
| PECO | $183,801 | $66,439 | (64%) |
| PENELEC | $162,675 | $67,319 | (59%) |
| Pepco | $204,536 | $72,532 | (65%) |
| PPL | $184,864 | $69,761 | (62%) |
| PSEG | $167,942 | $56,705 | (66%) |
| RECO | $117,596 | $66,248 | (44%) |
| PJM | $70,556 | $30,389 | (57%) |


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

| | Real-Time Economic | Day-Ahead Economic | Actual Difference | Percent Difference |
|---|---|---|---|---|
| 2000 | $8,498 | $7,418 | $1,080 | 13% |
| 2001 | $30,254 | $20,390 | $9,864 | 33% |
| 2002 | $14,496 | $13,921 | $575 | 4% |
| 2003 | $2,763 | $1,282 | $1,481 | 54% |
| 2004 | $919 | $1 | $918 | 100% |
| 2005 | $6,141 | $2,996 | $3,145 | 51% |
| 2006 | $10,996 | $5,229 | $5,767 | 52% |
| 2007 | $17,933 | $6,751 | $11,183 | 62% |
| 2008 | $12,442 | $6,623 | $5,819 | 47% |
| 2009 (Jan - Jun) | $2,180 | $508 | $1,673 | 77% |

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

| | Real-Time Economic | Day-Ahead Economic | Actual Difference | Percent Difference |
|---|---|---|---|---|
| 2000 | $24,794 | $26,132 | ($1,338) | (5%) |
| 2001 | $54,206 | $48,253 | $5,953 | 11% |
| 2002 | $38,625 | $35,993 | $2,631 | 7% |
| 2003 | $27,155 | $21,865 | $5,290 | 19% |
| 2004 | $27,389 | $18,193 | $9,196 | 34% |
| 2005 | $35,608 | $28,413 | $7,196 | 20% |
| 2006 | $44,692 | $31,670 | $13,023 | 29% |
| 2007 | $66,616 | $44,434 | $22,183 | 33% |
| 2008 | $62,039 | $47,342 | $14,697 | 24% |
| 2009 (Jan - Jun) | $15,888 | $13,598 | $2,290 | 14% |

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

| | Real-Time Economic | Day-Ahead Economic | Actual Difference | Percent Difference |
|---|---|---|---|---|
| 2000 | $108,624 | $116,784 | ($8,159) | (8%) |
| 2001 | $95,361 | $95,119 | $242 | 0% |
| 2002 | $96,828 | $97,493 | ($665) | (1%) |
| 2003 | $159,912 | $162,285 | ($2,374) | (1%) |
| 2004 | $124,497 | $113,892 | $10,605 | 9% |
| 2005 | $222,911 | $220,824 | $2,087 | 1% |
| 2006 | $177,852 | $167,282 | $10,571 | 6% |
| 2007 | $244,419 | $221,757 | $22,662 | 9% |
| 2008 | $179,457 | $174,191 | $5,267 | 3% |
| 2009 (Jan - Jun) | $31,711 | $30,389 | $1,321 | 4% |

## Net Revenue Adequacy

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

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

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

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | 20-Year Levelized Fixed Cost | 2008 Percent Recovery | 2009 Percent Recovery |
|---|---|---|---|---|---|
| AECO | $61,153 | $31,291 | $123,640 | 49% | 25% |
| AEP | $12,403 | $21,525 | $123,640 | 10% | 17% |
| AP | $22,790 | $29,870 | $123,640 | 18% | 24% |
| BGE | $54,934 | $42,919 | $123,640 | 44% | 35% |
| ComEd | $11,530 | $20,762 | $123,640 | 9% | 17% |
| DAY | $12,609 | $21,029 | $123,640 | 10% | 17% |
| DLCO | $11,874 | $20,892 | $123,640 | 10% | 17% |
| Dominion | $26,923 | $26,235 | $123,640 | 22% | 21% |
| DPL | $47,922 | $32,392 | $123,640 | 39% | 26% |
| JCPL | $52,002 | $31,977 | $123,640 | 42% | 26% |
| Met-Ed | $21,593 | $26,204 | $123,640 | 17% | 21% |
| PECO | $43,704 | $30,549 | $123,640 | 35% | 25% |
| PENELEC | $12,586 | $22,894 | $123,640 | 10% | 19% |
| Pepco | $56,172 | $42,549 | $123,640 | 45% | 34% |
| PPL | $20,044 | $25,438 | $123,640 | 16% | 21% |
| PSEG | $46,243 | $31,380 | $123,640 | 37% | 25% |
| RECO | $43,156 | $29,720 | $123,640 | 35% | 24% |
| PJM | $21,750 | $23,845 | $123,640 | 18% | 19% |

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

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | 20-Year Levelized Fixed Cost | 2008 Percent Recovery | 2009 Percent Recovery |
|---|---|---|---|---|---|
| AECO | $105,836 | $55,451 | $171,361 | 62% | 32% |
| AEP | $24,810 | $37,226 | $171,361 | 14% | 22% |
| AP | $47,933 | $56,641 | $171,361 | 28% | 33% |
| BGE | $96,953 | $67,829 | $171,361 | 57% | 40% |
| ComEd | $23,159 | $34,516 | $171,361 | 14% | 20% |
| DAY | $26,231 | $37,012 | $171,361 | 15% | 22% |
| DLCO | $23,348 | $35,505 | $171,361 | 14% | 21% |
| Dominion | $60,901 | $51,940 | $171,361 | 36% | 30% |
| DPL | $87,785 | $57,021 | $171,361 | 51% | 33% |
| JCPL | $103,193 | $56,641 | $171,361 | 60% | 33% |
| Met-Ed | $57,422 | $47,478 | $171,361 | 34% | 28% |
| PECO | $81,258 | $51,917 | $171,361 | 47% | 30% |
| PENELEC | $31,996 | $38,081 | $171,361 | 19% | 22% |
| Pepco | $96,927 | $66,347 | $171,361 | 57% | 39% |
| PPL | $54,966 | $45,782 | $171,361 | 32% | 27% |
| PSEG | $94,630 | $58,504 | $171,361 | 55% | 34% |
| RECO | $85,683 | $52,862 | $171,361 | 50% | 31% |
| PJM | $43,920 | $39,673 | $171,361 | 26% | 23% |

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

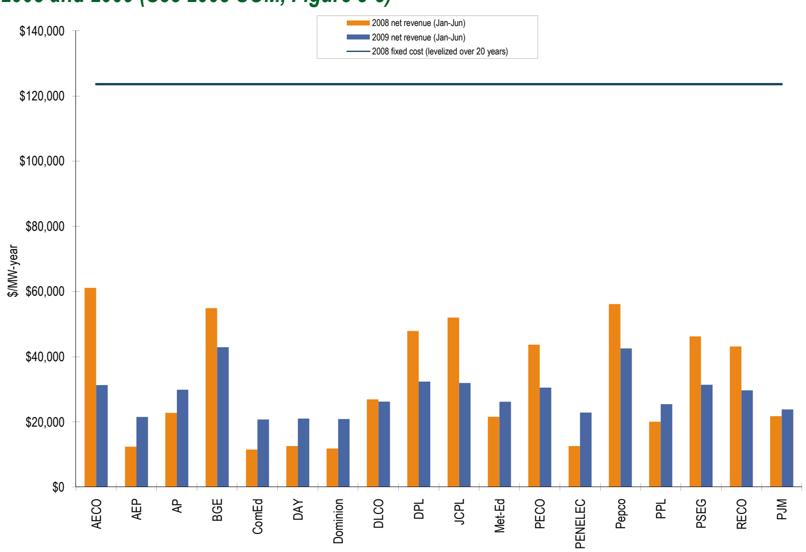


*Figure 3-2 New entrant CC zonal net revenue for January through June 2008 and 2009 with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Figure 3-5)*

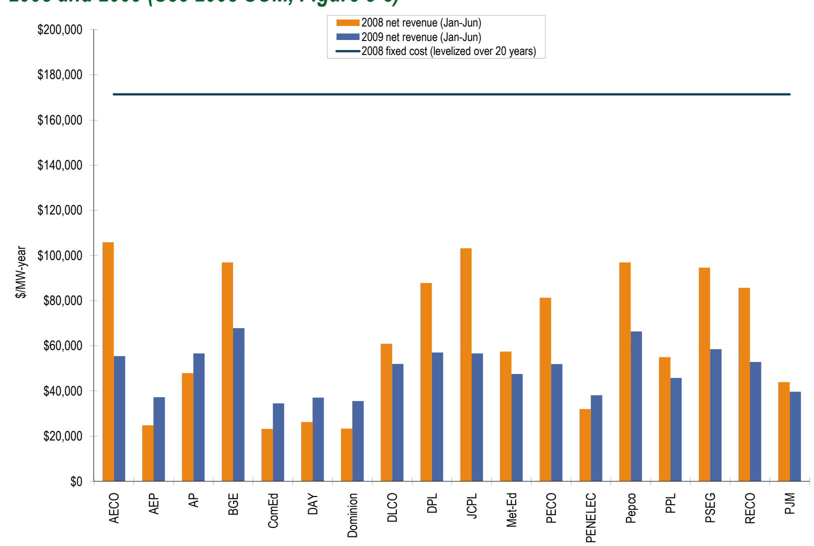



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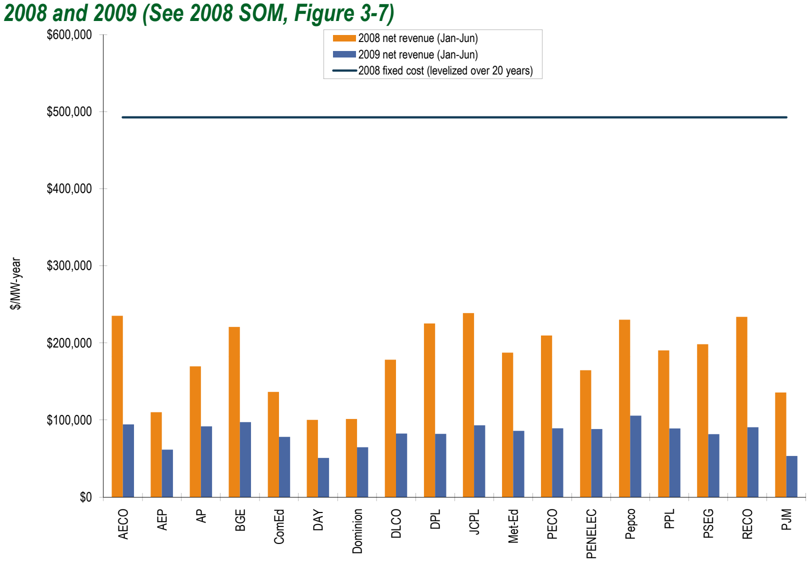
*Table 3-22 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 SOM, Table 3-28)*

| Zone | 2008 (Jan - Jun) | 2009 (Jan - Jun) | 20-Year Levelized Fixed Cost | 2008 Percent Recovery | 2009 Percent Recovery |
|---|---|---|---|---|---|
| AECO | $235,299 | $94,506 | $492,780 | 48% | 19% |
| AEP | $110,315 | $61,750 | $492,780 | 22% | 13% |
| AP | $169,716 | $91,846 | $492,780 | 34% | 19% |
| BGE | $220,952 | $97,301 | $492,780 | 45% | 20% |
| ComEd | $136,532 | $78,327 | $492,780 | 28% | 16% |
| DAY | $100,312 | $50,930 | $492,780 | 20% | 10% |
| DLCO | $101,420 | $64,726 | $492,780 | 21% | 13% |
| Dominion | $178,372 | $82,447 | $492,780 | 36% | 17% |
| DPL | $225,296 | $82,106 | $492,780 | 46% | 17% |
| JCPL | $238,863 | $93,273 | $492,780 | 48% | 19% |
| Met-Ed | $187,554 | $86,012 | $492,780 | 38% | 17% |
| PECO | $209,834 | $89,349 | $492,780 | 43% | 18% |
| PENELEC | $164,723 | $88,455 | $492,780 | 33% | 18% |
| Pepco | $230,335 | $105,845 | $492,780 | 47% | 21% |
| PPL | $190,393 | $89,089 | $492,780 | 39% | 18% |
| PSEG | $198,378 | $81,853 | $492,780 | 40% | 17% |
| RECO | $233,873 | $90,697 | $492,780 | 47% | 18% |
| PJM | $135,891 | $53,477 | $492,780 | 28% | 11% |

*Figure 3-3 New entrant CP zonal net revenue for January through June 2008 and 2009 with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through June 2008 and 2009 (See 2008 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, 2009 (See 2008 SOM, Table 3-30)*[3, 4]

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

### Energy Production by Fuel Source

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

| | GWh | Percent |
|---|---|---|
| Coal | 175,095.0 | 51.3% |
| Gas | 29,493.0 | 8.6% |
| Hydroelectric | 6,991.8 | 2.0% |
| Nuclear | 123,217.3 | 36.1% |
| Oil | 844.6 | 0.2% |
| Solar | 1.8 | 0.0% |
| Solid Waste | 2,895.3 | 0.8% |
| Wind | 2,712.0 | 0.8% |
| Total | 341,250.9 | 100.0% |

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

4 Wind-based resources accounted for 297.8 MW of installed capacity in PJM on June 1, 2009. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 13 percent factor. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

## Planned Generation Additions

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

| | MW |
|---|---|
| 2000 | 505 |
| 2001 | 872 |
| 2002 | 3,841 |
| 2003 | 3,524 |
| 2004 | 1,935 |
| 2005 | 819 |
| 2006 | 471 |
| 2007 | 1,265 |
| 2008 | 2,777 |
| 2009 | 410 |

## PJM Generation Queues

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

| | MW in the Queue 2008 | MW in the Queue 2009 | Year-to-Year Change (MW) | Year-to-Year Change |
|---|---|---|---|---|
| 2009 | 9,023 | 12,701 | 3,679 | 41% |
| 2010 | 18,052 | 16,162 | (1,889) | (10%) |
| 2011 | 17,253 | 16,282 | (972) | (6%) |
| 2012 | 15,527 | 12,794 | (2,734) | (18%) |
| 2013 | 7,920 | 9,588 | 1,668 | 21% |
| 2014 | 11,965 | 12,450 | 485 | 4% |
| 2015 | 2,436 | 2,437 | 1 | 0% |
| 2016 | 0 | 1,000 | 1,000 | NA |
| 2018 | 1,594 | 1,594 | 0 | 0% |
| Total | 83,770 | 85,008 | 1,238 | 1% |

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

| Queue | Active | In-Service | Under Construction | Withdrawn | Total |
|---|---|---|---|---|---|
| A Expired 31-Jan-98 | 0 | 8,121 | 0 | 17,347 | 25,468 |
| B Expired 31-Jan-99 | 0 | 4,671 | 0 | 15,833 | 20,503 |
| C Expired 31-Jul-99 | 0 | 531 | 0 | 4,151 | 4,682 |
| D Expired 31-Jan-00 | 0 | 851 | 0 | 7,603 | 8,454 |
| E Expired 31-Jul-00 | 0 | 795 | 0 | 16,887 | 17,682 |
| F Expired 31-Jan-01 | 0 | 52 | 0 | 3,093 | 3,145 |
| G Expired 31-Jul-01 | 0 | 486 | 630 | 21,986 | 23,102 |
| H Expired 31-Jan-02 | 0 | 603 | 0 | 8,522 | 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 | 0 | 2,516 | 2,643 |
| L Expired 31-Jan-04 | 20 | 257 | 0 | 4,014 | 4,290 |
| M Expired 31-Jul-04 | 0 | 319 | 186 | 3,978 | 4,482 |
| N Expired 31-Jan-05 | 1,462 | 2,263 | 88 | 6,714 | 10,527 |
| O Expired 31-Jul-05 | 2,708 | 748 | 487 | 3,831 | 7,774 |
| P Expired 31-Jan-06 | 2,611 | 816 | 1,840 | 3,450 | 8,717 |
| Q Expired 31-Jul-06 | 5,216 | 675 | 2,491 | 6,383 | 14,765 |
| R Expired 31-Jan-07 | 8,689 | 297 | 566 | 13,289 | 22,840 |
| S Expired 31-Jul-07 | 9,515 | 590 | 1,381 | 9,407 | 20,892 |
| T Expired 31-Jan-08 | 22,909 | 158 | 193 | 5,227 | 28,486 |
| U Expired 31-Jan-09 | 20,142 | 29 | 90 | 14,581 | 34,841 |
| V Expires 31-Jan-10 | 3,786 | 0 | 0 | 0 | 3,786 |
| Total | 77,057 | 22,530 | 7,951 | 173,393 | 280,931 |

5 The *2009 Quarterly State of the Market Report for PJM: January through June* 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.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## Distribution of Units in the Queues

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

| | Battery | CC | CT | Diesel | Hydro | Nuclear | Solar | Steam | Wind | Unknown | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | 0 | 0 | 939 | 4 | 0 | 0 | 4 | 665 | 1,416 | 0 | 3,028 |
| AEP | 0 | 1,035 | 594 | 7 | 112 | 84 | 5 | 3,813 | 8,071 | 53 | 13,774 |
| AP | 0 | 930 | 604 | 0 | 165 | 0 | 0 | 1,304 | 1,751 | 0 | 4,755 |
| BGE | 0 | 220 | 376 | 0 | 0 | 0 | 0 | 0 | 0 | 132 | 728 |
| ComEd | 0 | 1,680 | 1,044 | 94 | 0 | 392 | 0 | 1,326 | 27,157 | 44 | 31,737 |
| DAY | 0 | 0 | 10 | 2 | 0 | 0 | 0 | 12 | 597 | 0 | 621 |
| DLCO | 0 | 0 | 0 | 0 | 87 | 75 | 0 | 0 | 0 | 0 | 162 |
| DPL | 20 | 0 | 280 | 0 | 0 | 0 | 0 | 23 | 1,050 | 20 | 1,393 |
| Dominion | 0 | 3,923 | 1,011 | 29 | 30 | 1,944 | 0 | 326 | 230 | 166 | 7,660 |
| JCPL | 0 | 2,750 | 27 | 30 | 1 | 0 | 46 | 0 | 0 | 0 | 2,854 |
| Met-Ed | 0 | 1,745 | 122 | 86 | 0 | 24 | 0 | 0 | 0 | 0 | 1,977 |
| PECO | 1 | 2,460 | 595 | 2 | 0 | 180 | 1 | 18 | 0 | 0 | 3,257 |
| PENELEC | 0 | 0 | 161 | 16 | 32 | 0 | 0 | 50 | 1,792 | 0 | 2,051 |
| Pepco | 0 | 1,195 | 245 | 5 | 0 | 1,640 | 0 | 0 | 0 | 20 | 3,105 |
| PPL | 0 | 1,400 | 137 | 2 | 143 | 1,600 | 21 | 120 | 352 | 153 | 3,926 |
| PSEG | 0 | 1,875 | 1,047 | 0 | 1,000 | 0 | 60 | 0 | 0 | 0 | 3,982 |
| Total | 21 | 19,213 | 7,192 | 277 | 1,569 | 5,939 | 137 | 7,657 | 42,415 | 588 | 85,008 |

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

| | Battery | CC | CT | Diesel | Hydroelectric | Nuclear | Steam | Solar | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | 0 | 0 | 641 | 23 | 0 | 0 | 1,257 | 0 | 8 | 1,928 |
| AEP | 0 | 4,355 | 3,581 | 57 | 1,001 | 2,106 | 21,255 | 0 | 400 | 32,756 |
| AP | 0 | 1,129 | 1,140 | 36 | 108 | 0 | 7,974 | 0 | 245 | 10,632 |
| BGE | 0 | 0 | 849 | 3 | 0 | 1,735 | 2,965 | 0 | 0 | 5,552 |
| ComEd | 0 | 1,836 | 7,217 | 108 | 0 | 10,336 | 7,094 | 0 | 1,003 | 27,594 |
| DAY | 0 | 0 | 1,377 | 52 | 0 | 0 | 3,551 | 0 | 0 | 4,980 |
| DLCO | 0 | 0 | 0 | 0 | 6 | 1,741 | 1,259 | 0 | 0 | 3,006 |
| DPL | 0 | 364 | 2,473 | 95 | 0 | 0 | 2,016 | 0 | 0 | 4,948 |
| Dominion | 0 | 3,216 | 3,786 | 156 | 2,955 | 3,425 | 8,456 | 0 | 0 | 21,993 |
| External | 0 | 974 | 1,890 | 0 | 0 | 439 | 9,314 | 0 | 185 | 12,802 |
| JCPL | 0 | 856 | 1,430 | 25 | 400 | 615 | 540 | 0 | 0 | 3,865 |
| Met-Ed | 0 | 2,000 | 407 | 24 | 20 | 786 | 860 | 0 | 0 | 4,097 |
| PECO | 1 | 2,540 | 833 | 7 | 1,642 | 4,488 | 2,129 | 3 | 0 | 11,643 |
| PENELEC | 0 | 0 | 287 | 47 | 521 | 0 | 6,830 | 0 | 294 | 7,979 |
| Pepco | 0 | 0 | 1,440 | 9 | 0 | 0 | 4,829 | 0 | 0 | 6,278 |
| PPL | 0 | 1,662 | 729 | 63 | 571 | 2,275 | 5,830 | 0 | 217 | 11,347 |
| PSEG | 0 | 2,921 | 2,852 | 0 | 5 | 3,493 | 1,656 | 0 | 0 | 10,927 |
| Total | 1 | 21,853 | 30,931 | 706 | 7,229 | 31,439 | 87,813 | 3 | 2,352 | 182,326 |

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

| Age (years) | Battery | CC | CT | Diesel | Hydro | Nuclear | Steam | Solar | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Less than 10 | 1 | 18,568 | 19,150 | 400 | 52 | 0 | 1,327 | 3 | 2,352 | 41,852 |
| 10 to 20 | 0 | 3,037 | 4,073 | 121 | 37 | 1,134 | 7,982 | 0 | 0 | 16,383 |
| 20 to 30 | 0 | 158 | 20 | 20 | 2,807 | 14,787 | 9,043 | 0 | 0 | 26,834 |
| 30 to 40 | 0 | 90 | 5,917 | 47 | 451 | 15,518 | 35,515 | 0 | 0 | 57,538 |
| 40 to 50 | 0 | 0 | 1,771 | 115 | 2,470 | 0 | 21,074 | 0 | 0 | 25,430 |
| 50 to 60 | 0 | 0 | 0 | 4 | 348 | 0 | 12,234 | 0 | 0 | 12,586 |
| 60 to 70 | 0 | 0 | 0 | 0 | 107 | 0 | 491 | 0 | 0 | 598 |
| 70 to 80 | 0 | 0 | 0 | 0 | 239 | 0 | 149 | 0 | 0 | 388 |
| 80 to 90 | 0 | 0 | 0 | 0 | 492 | 0 | 0 | 0 | 0 | 492 |
| 90 to 100 | 0 | 0 | 0 | 0 | 194 | 0 | 0 | 0 | 0 | 194 |
| 100 and over | 0 | 0 | 0 | 0 | 32 | 0 | 0 | 0 | 0 | 32 |
| Total | 1 | 21,853 | 30,931 | 706 | 7,229 | 31,439 | 87,813 | 3 | 2,352 | 182,326 |

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

| | Battery | CC | CT | Diesel | Hydro | Nuclear | Solar | Steam | Wind | Unknown | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| EMAAC | 21 | 7,085 | 2,888 | 36 | 1,001 | 180 | 112 | 726 | 2,466 | 0 | 14,514 |
| Non-MAAC | 0 | 7,568 | 3,263 | 132 | 394 | 2,495 | 5 | 6,781 | 37,805 | 263 | 58,707 |
| SWMAAC | 0 | 1,415 | 621 | 5 | 0 | 1,640 | 0 | 0 | 0 | 152 | 3,833 |
| WMAAC | 0 | 3,145 | 420 | 104 | 175 | 1,624 | 21 | 173 | 2,144 | 150 | 7,954 |
| Total | 21 | 19,213 | 7,192 | 277 | 1,569 | 5,939 | 137 | 7,680 | 42,415 | 565 | 85,008 |

*Table 3-32 Comparison of generators 40 years and older with planned capacity additions (MW): Through 2018[7] (See 2008 SOM, Table 3-40)*

| Area | Unit Type | Capacity of Generators 40 Years or Older | Percent of Area Total | Capacity of Generators of All Ages | Percent of Area Total | Additional Capacity through 2018 | Estimated Capacity 2018 | Percent of Area Total |
|---|---|---|---|---|---|---|---|---|
| EMAAC | Battery | 0 | 0.0% | 1 | 0.0% | 21 | 22 | 0.1% |
| | Combined Cycle | 0 | 0.0% | 6,681 | 20.1% | 7,085 | 13,766 | 31.5% |
| | Combustion Turbine | 627 | 10.3% | 8,228 | 24.7% | 2,888 | 10,489 | 24.0% |
| | Diesel | 49 | 0.8% | 150 | 0.5% | 36 | 137 | 0.3% |
| | Hydroelectric | 2,042 | 33.5% | 2,047 | 6.1% | 1,001 | 3,048 | 7.0% |
| | Nuclear | 0 | 0.0% | 8,596 | 25.8% | 180 | 8,776 | 20.1% |
| | Solar | 0 | 0.0% | 3 | 0.0% | 112 | 115 | 0.3% |
| | Steam | 3,384 | 55.5% | 7,598 | 22.8% | 726 | 4,939 | 11.3% |
| | Wind | 0 | 0.0% | 8 | 0.0% | 2,466 | 2,474 | 5.7% |
| | Unknown | 0 | 0.0% | 0 | 0.0% | 0 | 0 | 0.0% |
| | EMAAC Total | 6,102 | 100.0% | 33,311 | 100.0% | 14,514 | 43,765 | 100.0% |
| Non-MAAC | Combined Cycle | 0 | 0.0% | 11,510 | 10.1% | 7,568 | 19,078 | 12.8% |
| | Combustion Turbine | 631 | 2.5% | 18,991 | 16.7% | 3,263 | 21,623 | 14.5% |
| | Diesel | 34 | 0.1% | 409 | 0.4% | 132 | 507 | 0.3% |
| | Hydroelectric | 1,396 | 5.6% | 4,070 | 3.6% | 394 | 4,464 | 3.0% |
| | Nuclear | 0 | 0.0% | 18,047 | 15.9% | 2,495 | 20,542 | 13.8% |
| | Solar | 0 | 0.0% | 0 | 0.0% | 5 | 5 | 0.0% |
| | Steam | 23,002 | 91.8% | 58,903 | 51.8% | 6,781 | 42,682 | 28.7% |
| | Wind | 0 | 0.0% | 1,833 | 1.6% | 37,805 | 39,639 | 26.6% |
| | Unknown | 0 | 0.0% | 0 | 0.0% | 263 | 263 | 0.2% |
| | Non-MAAC Total | 25,063 | 100.0% | 113,763 | 100.0% | 58,707 | 148,803 | 100.0% |
| SWMAAC | Combined Cycle | 0 | 0.0% | 0 | 0.0% | 1,415 | 1,415 | 11.6% |
| | Combustion Turbine | 315 | 9.0% | 2,289 | 19.4% | 621 | 2,595 | 21.3% |
| | Diesel | 0 | 0.0% | 12 | 0.1% | 5 | 17 | 0.1% |
| | Nuclear | 0 | 0.0% | 1,735 | 14.7% | 1,640 | 3,375 | 27.8% |
| | Steam | 3,192 | 91.0% | 7,793 | 65.9% | 0 | 4,602 | 37.9% |
| | Unknown | 0 | 0.0% | 0 | 0.0% | 152 | 152 | 1.3% |
| | SWMAAC Total | 3,507 | 100.0% | 11,830 | 100.0% | 3,833 | 12,156 | 100.0% |
| WMAAC | Combined Cycle | 0 | 0.0% | 3,662 | 15.6% | 3,145 | 6,807 | 25.4% |
| | Combustion Turbine | 198 | 3.9% | 1,423 | 6.1% | 420 | 1,645 | 6.1% |
| | Diesel | 35 | 0.7% | 135 | 0.6% | 104 | 204 | 0.8% |
| | Hydroelectric | 444 | 8.8% | 1,112 | 4.7% | 175 | 1,286 | 4.8% |
| | Nuclear | 0 | 0.0% | 3,061 | 13.1% | 1,624 | 4,685 | 17.5% |
| | Solar | 0 | 0.0% | 0 | 0.0% | 21 | 21 | 0.1% |
| | Steam | 4,370 | 86.6% | 13,519 | 57.7% | 173 | 9,322 | 34.8% |
| | Wind | 0 | 0.0% | 511 | 2.2% | 2,144 | 2,655 | 9.9% |
| | Unknown | 0 | 0.0% | 0 | 0.0% | 150 | 150 | 0.6% |
| | WMAAC Total | 5,047 | 100.0% | 23,422 | 100.0% | 7,954 | 26,773 | 100.0% |
| All Areas | Total | 39,719 | | 182,326 | | 85,008 | 231,497 | |

## Characteristic of Wind Units

*Table 3-33 Capacity factor of wind units in PJM, January through June 2009 (New Table)*

| Type of Resource | Capacity Factor | Total Hours | Installed Capacity |
|---|---|---|---|
| Energy-Only Resource | 30.1% | 81,940 | 613 |
| Capacity Resource | 32.2% | 46,133 | 1,739 |
| All Units | 30.7% | 128,073 | 2,352 |

*Table 3-34 Wind resources in Real-Time offering at a negative price in PJM, June 2009[8] (New Table)*

| | Average MW Offered Daily | Intervals Marginal | Percent of All Intervals |
|---|---|---|---|
| At Negative Price | 115.0 | 5 | 0.06% |
| All Wind | 1,104.9 | 6 | 0.07% |

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

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


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

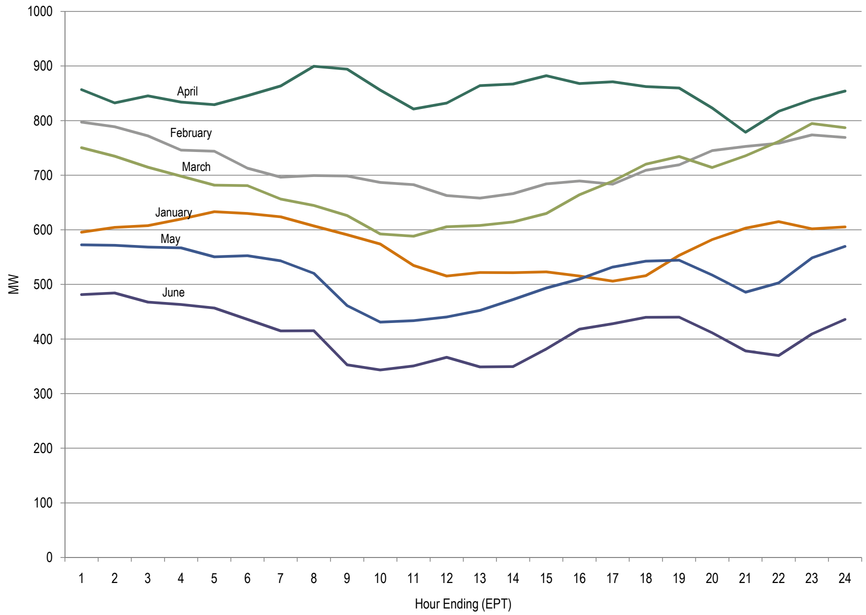



*Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through June 2009 (New Figure)*

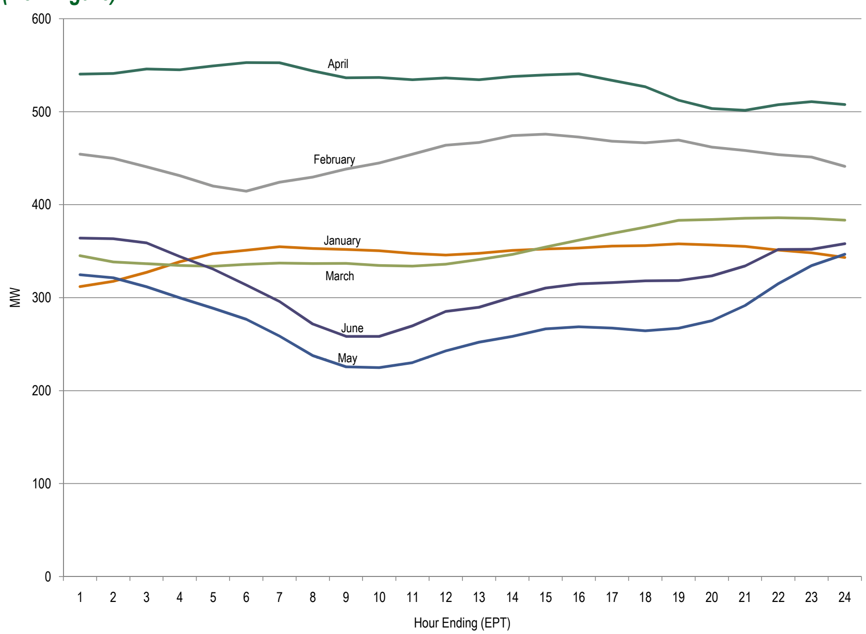
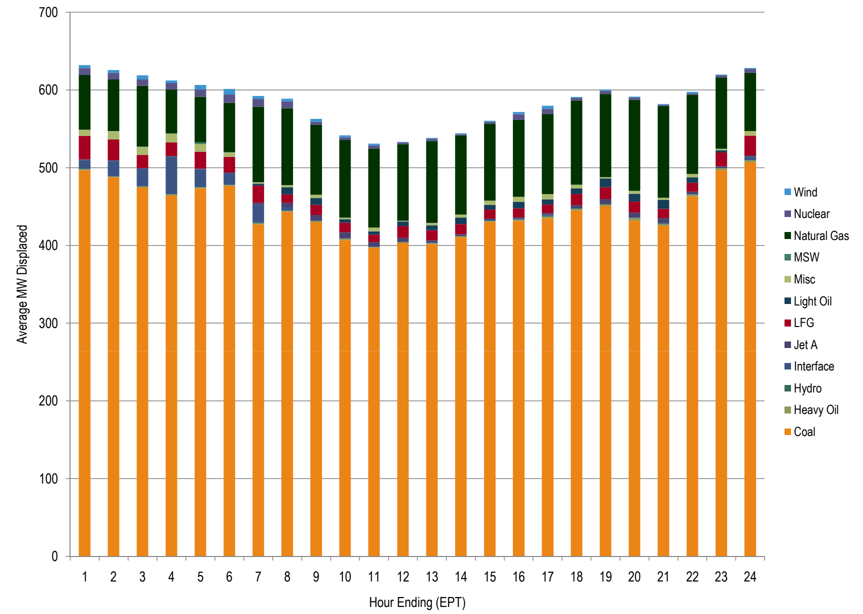



*Figure 3-6 Marginal fuel displacement by wind generation in PJM, January through June 2009 (New Figure)*



## Operating Reserve

### Overall Results

*Table 3-35 Monthly operating reserve charges: January through June 2008 and 2009[9] (See 2008 SOM, Table 3-45)*

| | 2008 (Jan - Jun) Charges | | | | 2009 (Jan - Jun) Charges | | | |
|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | Synchronous Condensing | Balancing | Total | Day-Ahead | Synchronous Condensing | Balancing | Total |
| Jan | $4,126,221 | $456,972 | $39,935,491 | $44,518,684 | $9,260,150 | $1,328,814 | $29,991,144 | $40,580,108 |
| Feb | $3,731,017 | $200,456 | $23,165,838 | $27,097,312 | $7,434,068 | $839,679 | $16,500,510 | $24,774,257 |
| Mar | $2,904,498 | $249,900 | $18,916,241 | $22,070,639 | $9,549,963 | $108,664 | $25,889,938 | $35,548,565 |
| Apr | $4,213,578 | $209,366 | $22,559,577 | $26,982,522 | $6,998,364 | $19,929 | $13,227,874 | $20,246,168 |
| May | $10,873,205 | $202,397 | $22,970,363 | $34,045,964 | $6,024,108 | $5,543 | $15,197,148 | $21,226,799 |
| Jun | $7,064,877 | $575,927 | $65,597,311 | $73,238,115 | $6,722,329 | $0 | $19,077,096 | $25,799,425 |
| Total | $32,913,397 | $1,895,019 | $193,144,820 | $227,953,236 | $45,988,983 | $2,302,629 | $119,883,710 | $168,175,322 |
| Share of Annual Charges | 14.4% | 0.8% | 84.7% | 100.0% | 27.3% | 1.4% | 71.3% | 100.0% |

*Table 3-36 Regional balancing charges allocation: January through June 2008 and 2009 (New Table)*

| | Reliability Charges | | | Deviation Charges | | | | |
|---|---|---|---|---|---|---|---|---|
| | Real-Time Load | Real-Time Exports | Reliability Total | Demand Deviations | Supply Deviations | Generator Deviations | Deviations Total | Total |
| RTO | $2,749,936 | $108,748 | $2,858,684 | $34,212,966 | $20,980,028 | $10,893,912 | $66,086,906 | $68,945,590 |
| RTO | 3.0% | 0.1% | 3.1% | 36.8% | 22.6% | 11.7% | 71.1% | 74.2% |
| East | $324,661 | $11,529 | $336,190 | $3,382,299 | $1,927,684 | $989,854 | $6,299,837 | $6,636,027 |
| East | 0.3% | 0.0% | 0.4% | 3.6% | 2.1% | 1.1% | 6.8% | 7.1% |
| West | $14,474,332 | $667,966 | $15,142,298 | $1,111,579 | $755,649 | $369,206 | $2,236,433 | $17,378,731 |
| West | 15.6% | 0.7% | 16.3% | 1.2% | 0.8% | 0.4% | 2.4% | 18.7% |
| Total | $17,548,928 | $788,243 | $18,337,172 | $38,706,844 | $23,663,360 | $12,252,972 | $74,623,176 | $92,960,347 |
| Total | 18.9% | 0.8% | 19.7% | 41.6% | 25.5% | 13.2% | 80.3% | 100.0% |

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

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

| | 2008 (Jan - Jun) Deviations | | | | 2009 (Jan - Jun) Deviations | | | |
|---|---|---|---|---|---|---|---|---|
| | Demand (MWh) | Supply (MWh) | Generator (MWh) | Total (MWh) | Demand (MWh) | Supply (MWh) | Generator (MWh) | Total (MWh) |
| Jan | 8,172,164 | 3,297,121 | 2,572,113 | 14,041,398 | 9,136,874 | 5,677,781 | 2,637,940 | 17,452,595 |
| Feb | 6,728,062 | 3,046,290 | 2,546,510 | 12,320,861 | 7,044,678 | 4,232,679 | 2,107,229 | 13,384,585 |
| Mar | 6,392,821 | 2,520,387 | 2,405,061 | 11,318,269 | 7,214,090 | 4,426,764 | 2,410,544 | 14,051,398 |
| Apr | 5,951,654 | 3,127,726 | 2,224,157 | 11,303,537 | 6,873,427 | 3,872,032 | 2,275,152 | 13,020,611 |
| May | 6,624,696 | 3,787,650 | 2,699,616 | 13,111,962 | 6,958,699 | 5,184,983 | 2,386,124 | 14,529,806 |
| Jun | 8,117,669 | 3,179,999 | 2,644,016 | 13,941,684 | 8,569,879 | 4,603,052 | 2,637,411 | 15,810,343 |
| Total | 41,987,065 | 18,959,174 | 15,091,472 | 76,037,711 | 45,797,648 | 27,997,291 | 14,454,399 | 88,249,338 |
| Share of Annual Deviations | 55.2% | 24.9% | 19.8% | 100.0% | 51.9% | 31.7% | 16.4% | 100.0% |

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

| | Reliability Charges | | | Deviation Charges | | | | |
|---|---|---|---|---|---|---|---|---|
| | Real-Time Load (MWh) | Real-Time Exports (MWh) | Reliability Total | Demand Deviations (MWh) | Supply Deviations (MWh) | Generator Deviations (MWh) | Deviations Total | Total |
| RTO | 330,039,231 | 13,612,493 | 343,651,724 | 45,797,648 | 27,997,291 | 14,454,399 | 88,249,338 | 431,901,062 |
| East | 179,822,112 | 6,499,599 | 186,321,711 | 27,204,634 | 15,061,498 | 7,623,685 | 49,889,818 | 236,211,529 |
| West | 150,217,119 | 7,112,894 | 157,330,013 | 18,451,023 | 12,878,283 | 6,830,714 | 38,160,020 | 195,490,033 |

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

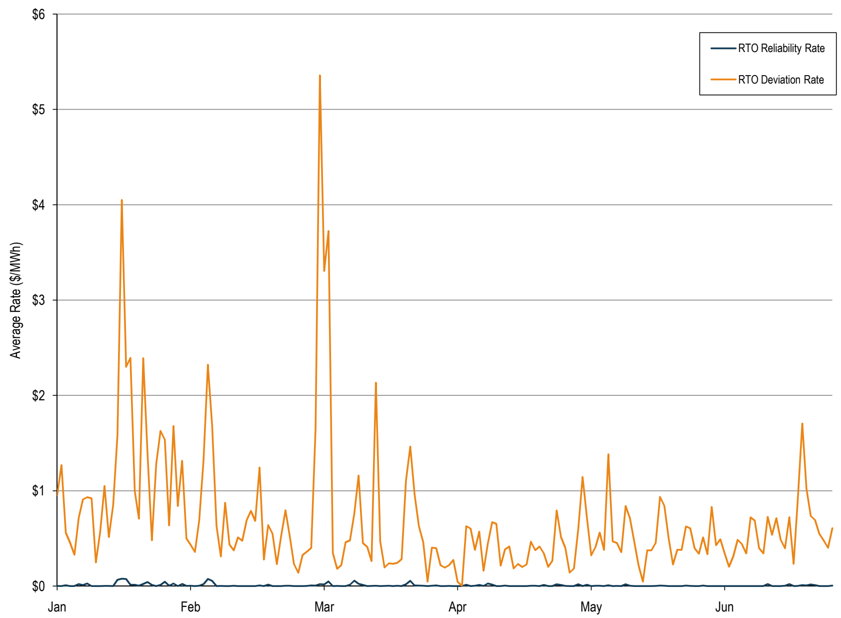
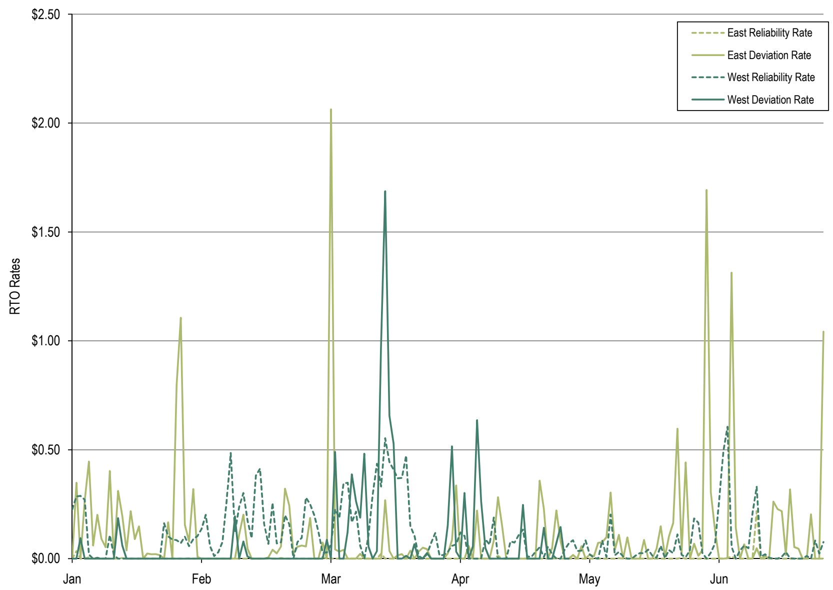



*Figure 3-8 Daily regional reliability and deviation rates: January through June 2009 (New Figure)*




## Balancing Operating Reserve Charge Rate

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

| | Reliability | Deviations |
|---|---|---|
| RTO | 0.007 | 0.702 |
| East | 0.002 | 0.114 |
| West | 0.101 | 0.057 |

## Operating Reserve Credits by Category

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

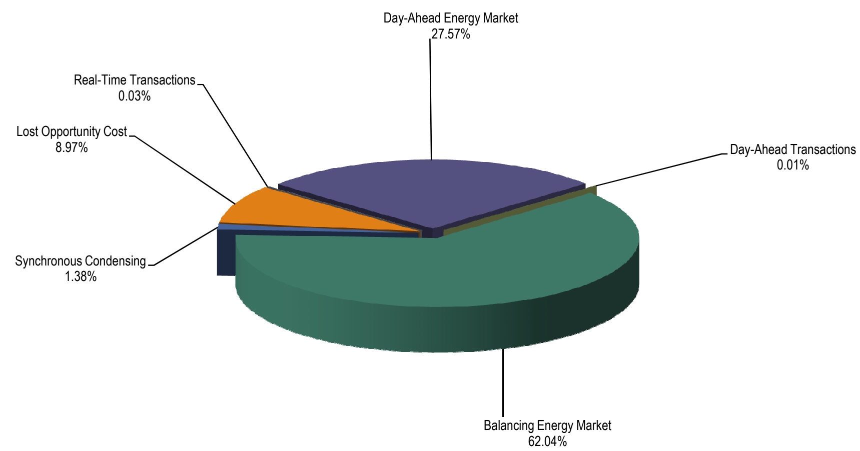




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*Table 3-40 Credits by month (By operating reserve market): January through June 2009 (See 2008 SOM, Table 3-49)*

| | Day-Ahead Generator | Day-Ahead Transactions | Synchronous Condensing | Balancing Generator | Balancing Transactions | Lost Opportunity Cost | Total |
|---|---|---|---|---|---|---|---|
| Jan | $9,260,150 | $0 | $1,328,814 | $26,443,459 | $0 | $3,547,685 | $40,580,108 |
| Feb | $7,434,068 | $0 | $839,679 | $14,406,379 | $31,258 | $2,062,873 | $24,774,257 |
| Mar | $9,542,383 | $7,580 | $108,664 | $22,220,993 | $13,249 | $3,508,074 | $35,400,943 |
| Apr | $6,998,364 | $0 | $19,929 | $10,731,331 | $6,942 | $1,830,088 | $19,586,655 |
| May | $6,024,108 | $0 | $5,543 | $13,714,645 | $0 | $1,488,712 | $21,233,008 |
| Jun | $6,711,471 | $10,858 | $0 | $15,940,386 | $0 | $2,510,286 | $25,173,000 |
| | | | | | | | |
| Total | $45,970,544 | $18,438 | $2,302,629 | $103,457,193 | $51,449 | $14,947,718 | $166,747,970 |

## Characteristics of Credits and Charges

### Types of Units

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

| Unit Type | Day-Ahead Generator | Synchronous Condensing | Balancing Generator | Lost Opportunity Cost | Total |
|---|---|---|---|---|---|
| Combined Cycle | 39.3% | 0.0% | 60.0% | 0.7% | $53,604,989 |
| Combustion Turbine | 1.3% | 5.2% | 77.6% | 15.9% | $44,697,492 |
| Diesel | 0.2% | 0.0% | 2.9% | 96.9% | $2,629,272 |
| Hydro | 0.0% | 0.3% | 99.7% | 0.0% | $166,159 |
| Nuclear | 0.0% | 0.0% | 0.0% | 100.0% | $150,645 |
| Steam | 37.1% | 0.0% | 55.6% | 7.3% | $65,429,277 |
| Wind Farm | 0.0% | 0.0% | 0.0% | 100.0% | $250 |

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

| Unit Type | Day-Ahead Generator | Synchronous Condensing | Balancing Generator | Lost Opportunity Cost |
|---|---|---|---|---|
| Combined Cycle | 45.9% | 0.0% | 31.1% | 2.4% |
| Combustion Turbine | 1.3% | 100.0% | 33.5% | 47.7% |
| Diesel | 0.0% | 0.0% | 0.1% | 17.1% |
| Hydro | 0.0% | 0.0% | 0.2% | 0.0% |
| Nuclear | 0.0% | 0.0% | 0.0% | 1.0% |
| Steam | 52.9% | 0.0% | 35.2% | 31.8% |
| Wind Farm | 0.0% | 0.0% | 0.0% | 0.0% |
| Total | $45,970,544 | $2,302,629 | $103,457,193 | $14,947,718 |

### Economic and Noneconomic Generation

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

| | All Hours | On Peak | Off Peak |
|---|---|---|---|
| Self-scheduled generation | 24.8% | 23.5% | 27.7% |
| Economic generation | 64.2% | 68.7% | 53.9% |
| Noneconomic generation | 10.0% | 7.3% | 16.4% |
| Regulation generation | 1.0% | 0.5% | 2.0% |
| Total | 100% | 100% | 100% |

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

| | Self-Scheduled Generation | Economic Generation | Noneconomic Generation | Regulation Generation |
|---|---|---|---|---|
| Combined cycle | 2.2% | 7.8% | 26.1% | 16.2% |
| Combustion turbine | 0.2% | 0.2% | 1.9% | 0.0% |
| Diesel | 0.2% | 0.0% | 0.0% | 0.0% |
| Hydroelectric | 2.4% | 0.7% | 0.0% | 0.0% |
| Steam | 93.9% | 91.3% | 72.0% | 83.7% |
| Wind | 1.2% | 0.0% | 0.0% | 0.0% |
| Total | 100% | 100% | 100% | 100% |

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

| | Self-Scheduled Generation | Economic Generation | Noneconomic Generation | Regulation Generation | Total |
|---|---|---|---|---|---|
| Combined cycle | 6.5% | 60.1% | 31.5% | 1.9% | 100% |
| Combustion turbine | 14.3% | 31.3% | 54.3% | 0.1% | 100% |
| Diesel | 73.4% | 19.4% | 7.2% | 0.0% | 100% |
| Hydroelectric | 56.8% | 43.2% | 0.0% | 0.0% | 100% |
| Steam | 25.8% | 65.3% | 8.0% | 0.9% | 100% |
| Wind | 99.1% | 0.9% | 0.0% | 0.0% | 100% |

## Geography of Balancing Credits and Charges

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

| | Eastern Region | | | | | | Western Region | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit Deviation Charges | Unit Deviation LOC Charges | Total Unit Deviation Charges | Balancing Generator Credit | LOC Credit | Total Balancing Credit | Unit Deviation Charges | Unit Deviation LOC Charges | Total Unit Deviation Charges | Balancing Generator Credit | LOC Credit | Total Balancing Credit | Total Unit Deviation Charges Percent of Total Operating Reserve Charges | Total Unit Deviation Credits Percent of Total Operating Reserve Credits |
| Jan | $2,139,517 | $312,053 | $2,451,569 | $21,038,966 | $2,607,437 | $23,646,403 | $1,508,492 | $250,222 | $1,758,714 | $5,404,493 | $940,247 | $6,344,741 | 10.4% | 66.5% |
| Feb | $838,506 | $168,497 | $1,007,003 | $7,814,120 | $1,685,163 | $9,499,283 | $669,918 | $153,709 | $823,627 | $6,592,259 | $377,710 | $6,969,970 | 7.4% | 59.5% |
| Mar | $1,572,526 | $349,336 | $1,921,862 | $13,125,363 | $2,280,516 | $15,405,879 | $1,251,529 | $257,801 | $1,509,330 | $9,095,630 | $1,227,558 | $10,323,188 | 9.6% | 64.5% |
| Apr | $522,037 | $164,054 | $686,091 | $3,978,840 | $1,094,655 | $5,073,494 | $501,154 | $149,107 | $650,262 | $6,752,492 | $735,433 | $7,487,925 | 6.6% | 56.4% |
| May | $729,050 | $119,822 | $848,872 | $6,750,078 | $1,288,656 | $8,038,734 | $628,669 | $120,320 | $748,990 | $6,964,567 | $200,056 | $7,164,623 | 7.5% | 65.7% |
| Jun | $1,090,103 | $212,220 | $1,302,323 | $8,647,384 | $1,996,522 | $10,643,906 | $801,470 | $199,890 | $1,001,361 | $7,293,001 | $513,764 | $7,806,765 | 8.9% | 65.0% |
| | | | | | | | | | | | | | | |
| Average | 56.2% | 54.0% | 55.9% | 59.3% | 73.3% | 61.1% | 43.8% | 46.0% | 44.1% | 40.7% | 26.7% | 38.9% | 8.4% | 62.9% |


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## Market Power Issues

### *Top 10 Units*

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

| | Units | | | Organizations | | |
|---|---|---|---|---|---|---|
| Rank | Total Credit | Total Credit Share | Total Credit Cumulative Distribution | Total Credit | Total Credit Share | Total Credit Cumulative Distribution |
| 1 | $18,989,859 | 11.4% | 11.4% | $53,037,032 | 31.8% | 31.8% |
| 2 | $12,992,666 | 7.8% | 19.2% | $36,819,954 | 22.1% | 53.9% |
| 3 | $6,713,051 | 4.0% | 23.2% | $11,610,012 | 7.0% | 60.9% |
| 4 | $5,818,956 | 3.5% | 26.7% | $10,438,977 | 6.3% | 67.1% |
| 5 | $5,519,629 | 3.3% | 30.0% | $9,194,798 | 5.5% | 72.7% |
| 6 | $5,326,982 | 3.2% | 33.2% | $7,145,293 | 4.3% | 76.9% |
| 7 | $3,029,911 | 1.8% | 35.0% | $5,791,157 | 3.5% | 80.4% |
| 8 | $2,356,878 | 1.4% | 36.4% | $3,238,158 | 1.9% | 82.4% |
| 9 | $2,217,461 | 1.3% | 37.8% | $3,118,188 | 1.9% | 84.2% |
| 10 | $2,024,680 | 1.2% | 39.0% | $2,743,466 | 1.6% | 85.9% |

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

| | Units | | | Organizations | | |
|---|---|---|---|---|---|---|
| Rank | Day Ahead Generator Credit | Day Ahead Generator Credit Share | Day Ahead Generator Credit Cumulative Distribution | Day Ahead Generator Credit | Day Ahead Generator Credit Share | Day Ahead Generator Credit Cumulative Distribution |
| 1 | $9,819,249 | 21.4% | 21.4% | $23,449,745 | 51.0% | 51.0% |
| 2 | $6,844,101 | 14.9% | 36.2% | $5,707,317 | 12.4% | 63.4% |
| 3 | $5,374,231 | 11.7% | 47.9% | $4,058,995 | 8.8% | 72.3% |
| 4 | $1,200,962 | 2.6% | 50.6% | $2,187,062 | 4.8% | 77.0% |
| 5 | $941,815 | 2.0% | 52.6% | $1,913,941 | 4.2% | 81.2% |
| 6 | $677,532 | 1.5% | 54.1% | $1,382,409 | 3.0% | 84.2% |
| 7 | $616,766 | 1.3% | 55.4% | $1,197,322 | 2.6% | 86.8% |
| 8 | $584,464 | 1.3% | 56.7% | $982,520 | 2.1% | 88.9% |
| 9 | $581,877 | 1.3% | 58.0% | $869,382 | 1.9% | 90.8% |
| 10 | $576,741 | 1.3% | 59.2% | $819,262 | 1.8% | 92.6% |

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

| | Units | | | Organizations | | |
|---|---|---|---|---|---|---|
| Rank | Synchronous Condensing Credit | Synchronous Condensing Credit Share | Synchronous Condensing Credit Cumulative Distribution | Synchronous Condensing Credit | Synchronous Condensing Credit Share | Synchronous Condensing Credit Cumulative Distribution |
| 1 | $199,676 | 8.7% | 8.7% | $2,051,535 | 89.1% | 89.1% |
| 2 | $197,058 | 8.6% | 17.2% | $165,168 | 7.2% | 96.3% |
| 3 | $192,296 | 8.4% | 25.6% | $75,847 | 3.3% | 99.6% |
| 4 | $189,164 | 8.2% | 33.8% | $5,133 | 0.2% | 99.8% |
| 5 | $187,366 | 8.1% | 41.9% | | | |
| 6 | $186,694 | 8.1% | 50.0% | | | |
| 7 | $181,954 | 7.9% | 57.9% | | | |
| 8 | $89,051 | 3.9% | 61.8% | | | |
| 9 | $84,254 | 3.7% | 65.5% | | | |
| 10 | $77,903 | 3.4% | 68.9% | | | |

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

| | Units | | | Organizations | | |
|---|---|---|---|---|---|---|
| Rank | Balancing Generator Credit | Balancing Generator Credit Share | Balancing Generator Credit Cumulative Distribution | Balancing Generator Credit | Balancing Generator Credit Share | Balancing Generator Credit Cumulative Distribution |
| 1 | $12,143,407 | 11.7% | 11.7% | $30,123,095 | 29.1% | 29.1% |
| 2 | $6,377,229 | 6.2% | 17.9% | $27,378,907 | 26.5% | 55.6% |
| 3 | $5,106,545 | 4.9% | 22.8% | $8,890,830 | 8.6% | 64.2% |
| 4 | $4,782,758 | 4.6% | 27.5% | $8,589,384 | 8.3% | 72.5% |
| 5 | $3,064,712 | 3.0% | 30.4% | $4,935,610 | 4.8% | 77.2% |
| 6 | $2,734,557 | 2.6% | 33.1% | $3,604,057 | 3.5% | 80.7% |
| 7 | $2,062,962 | 2.0% | 35.1% | $2,100,525 | 2.0% | 82.8% |
| 8 | $1,822,126 | 1.8% | 36.8% | $2,036,396 | 2.0% | 84.7% |
| 9 | $1,740,959 | 1.7% | 38.5% | $1,793,683 | 1.7% | 86.5% |
| 10 | $1,678,473 | 1.6% | 40.1% | $1,369,006 | 1.3% | 87.8% |

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

| | Units | | | Organizations | | |
|---|---|---|---|---|---|---|
| Rank | LOC Credit | LOC Credit Share | LOC Credit Cumulative Distribution | LOC Credit | LOC Credit Share | LOC Credit Cumulative Distribution |
| 1 | $1,172,459 | 7.8% | 7.8% | $7,144,333 | 47.8% | 47.8% |
| 2 | $1,003,375 | 6.7% | 14.6% | $2,037,592 | 13.6% | 61.4% |
| 3 | $978,634 | 6.5% | 21.1% | $989,542 | 6.6% | 68.0% |
| 4 | $869,881 | 5.8% | 26.9% | $931,002 | 6.2% | 74.3% |
| 5 | $862,761 | 5.8% | 32.7% | $689,762 | 4.6% | 78.9% |
| 6 | $831,725 | 5.6% | 38.3% | $665,671 | 4.5% | 83.3% |
| 7 | $689,762 | 4.6% | 42.9% | $457,096 | 3.1% | 86.4% |
| 8 | $463,631 | 3.1% | 46.0% | $398,245 | 2.7% | 89.1% |
| 9 | $433,445 | 2.9% | 48.9% | $268,250 | 1.8% | 90.9% |
| 10 | $388,048 | 2.6% | 51.5% | $156,846 | 1.0% | 91.9% |

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

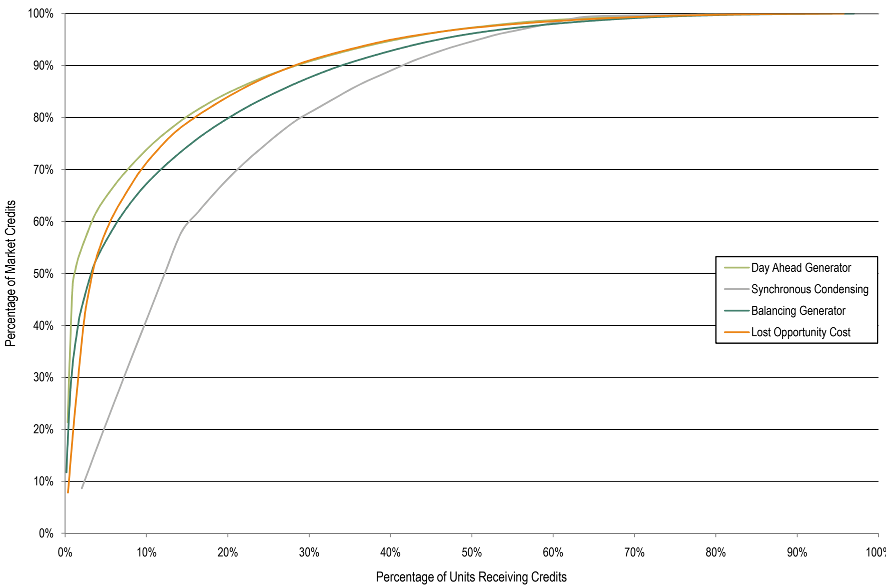
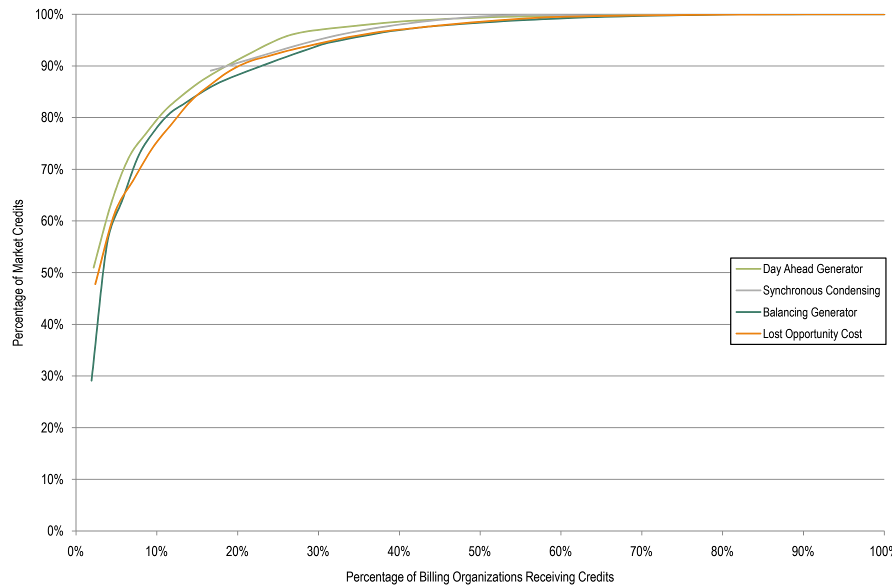



*Figure 3-11 Cumulative distribution of billing organizations receiving credits (By operating reserve market): January through June 2009 (See 2008 SOM, Figure 3-13)*




## Markup

### Unit Markup - Top 10 Units

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

| | Top 10 Units' Weighted Markup | Steam Share of Top 10 Units' Credits | Steam Units' in Top 10 Weighted Markup | Combined Cycle Share of Top 10 Units' Credits | Combined Cycle Units' in Top 10 Weighted Markup | Combustion Turbine Share of Top 10 Units' Credits | Combustion Turbine Units' in Top 10 Weighted Markup |
|---|---|---|---|---|---|---|---|
| 2009 (Jan -Jun) | (1.9%) | 42.7% | (7.1%) | 57.3% | .8% | 0.0% | NA |



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### Unit Markup - All Units

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

| Unit Type | Number of Units | Weighted Markup |
|---|---|---|
| Combustion Turbine | 361 | (1.9%) |
| Steam | 230 | (7.2%) |
| Combined Cycle | 46 | (11.7%) |
| Diesel | 20 | (62.9%) |
| Hydro | 8 | 284.6% |
| Nuclear | 2 | (30.0%) |
| Wind Farm | 1 | 0.0% |

## March 3, 2009

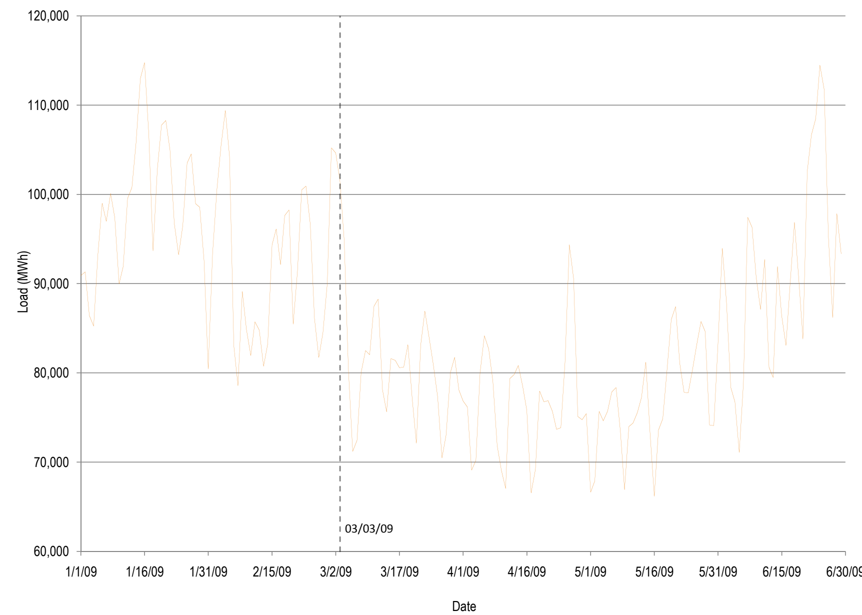
### A Spike in Operating Reserves Charges

A spike in the RTO balancing deviation rate occurred on Tuesday, March 3, 2009. On March 3, $2,836,708 was paid to generators in RTO deviation credits. The RTO deviation rate on March 3 was $5.3568/MWh ($2,836,708/529,545 MWh). (See Table 3-55.) The deviation rate was 6.68 standard deviations higher than the average RTO deviation rate of .7023 for the period of January 1, 2009 through June 30, 2009.

There appear to be several reasons for the large increase in operating reserve charges on March 3. The increase in load from March 1 to March 2, of 15,233 MW, was the third largest single day increase of the year, while the peak load on March 3 was 572 MW lower than that on March 2. The actual load for March 3 was substantially lower than the forecast load and real-time prices were lower than day-ahead prices. Some zonal LMPs increased sharply during the early morning load pickup hours which prompted extra units to be called on. In particular, one plant received operating reserve credits for start costs of six units that were called on, while only three of those units actually started. The payments to those units were about 24 percent of the total balancing operating reserves credits for the day.

While actual load was less than forecast, March 3, 2009 was still a relatively high PJM load day for the time of year. At HE 8, the PJM load reached 104,647 MWh, one of the highest hourly peaks in the six month period between January 1 and June 30. Figure 3-12 shows the daily PJM peak load for those six months.

*Figure 3-12 Daily PJM Peak Load: January 1, 2009 through June 30, 2009 (New Figure)*




Five minute zonal LMPs were just below $100 during the peak hours of March 3, but zonal prices increased substantially during the morning load pick up (Figure 3-13). Figure 3-14 shows the hourly zonal and PJM loads for the day.

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*Figure 3-13 Five Minute Zonal LMPs: March 3, 2009 (New Figure)*

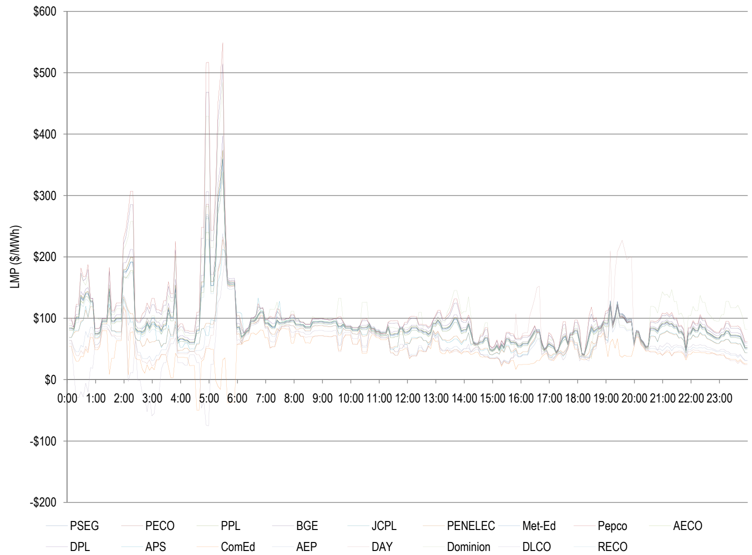
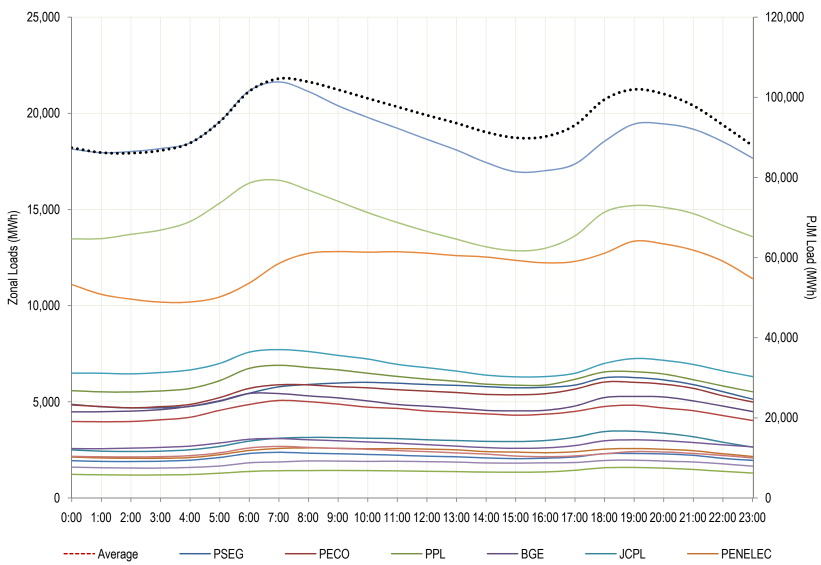



*Figure 3-14 Hourly Zonal Loads: March 3, 2009 (New Figure)*




The original day-ahead load forecast was greater than the actual real-time load for March 3 by an hourly average of 3,253 MW. The real-time forecasted load was greater than the actual real-time load by an hourly average of 2,579 MW. The two forecasts and actual real-time load are shown in Figure 3-15.

*Figure 3-15 Hourly PJM load forecast and actual real-time PJM load: March 3, 2009 (New Figure)*

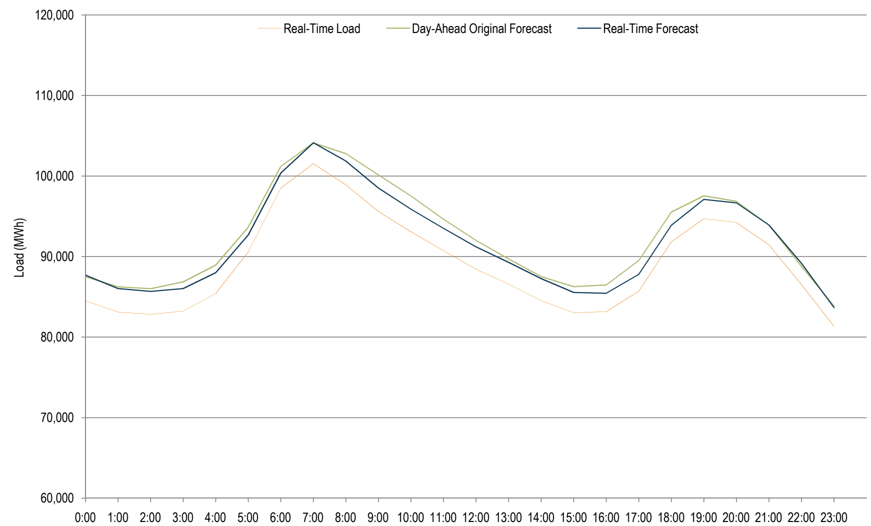



Figure 3-16 shows that the hourly integrated PJM real-time LMP was lower than the day-ahead LMP for 17 hours of the day on March 3, including all but one peak hour.


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*Figure 3-16 Hourly integrated PJM LMP: March 3, 2009 (New Figure)*

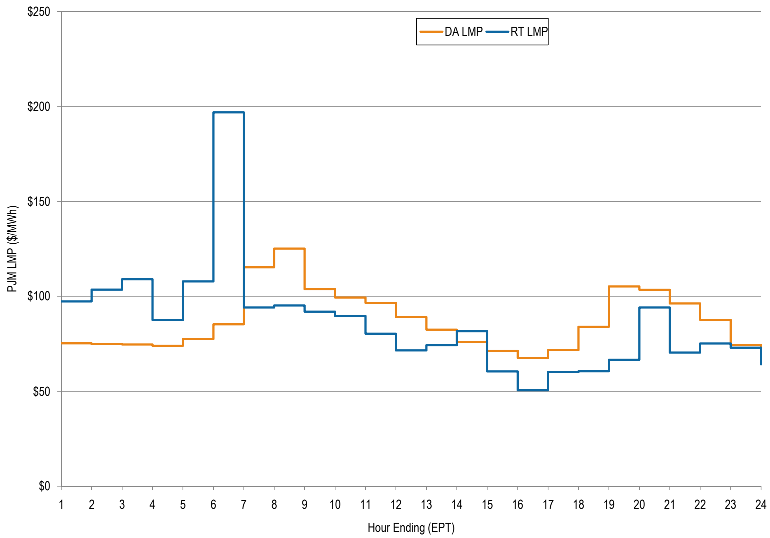


Table 3-54 shows a summary of outages by zone for March 3. The MW reduction is the sum of the MW on an outage, MW loss is the sum of each unit's reduction times the duration, and the zone EAF (Equivalent Availability Factor) is calculated as (1 – (MW loss / (zone capacity * 24 hours)).

*Table 3-54 Zonal Outage Summary: Tuesday, March 3, 2009 (New Table)*

| Zone | MW Reduction | MW Loss | Zone EAF |
|---|---|---|---|
| AECO | 609 | 14,372 | 68.2% |
| PENELEC | 1,478 | 34,835 | 79.9% |
| Dominion | 3,231 | 75,670 | 81.2% |
| BGE | 977 | 23,448 | 83.0% |
| AEP | 5,747 | 108,036 | 85.8% |
| PPL | 1,805 | 36,120 | 86.5% |
| DPL | 656 | 10,921 | 88.2% |
| PSEG | 1,534 | 28,005 | 89.2% |
| DAY | 633 | 16,099 | 89.4% |
| PECO | 1,474 | 30,871 | 89.5% |
| JCPL | 312 | 7,488 | 90.2% |
| ComEd | 2,591 | 59,699 | 90.7% |
| APS | 971 | 23,304 | 92.4% |
| External (XIC) | 584 | 9,900 | 92.7% |
| Pepco | 553 | 12,176 | 94.1% |
| DLCO | 150 | 2,760 | 96.0% |
| Met-Ed | 40 | 890 | 99.3% |

Table 3-55 shows the RTO, East, and West charges, credits, and MWh for March 3. RTO deviation credits were $2,836,708, or 96.7 percent, of the total credits for the day. Charges paid by demand deviations were 48.8 percent of the total charges for the day, while charges paid by supply deviations were 30.7 percent, and generator deviations 17.3 percent.

*Table 3-55 Regional Credits, Charges, and Deviations Breakdown: March 3, 2009 (New Table)*

| | Reliability | | | Deviations | | | | |
|---|---|---|---|---|---|---|---|---|
| | Real-Time Load | Real-Time Exports | Reliability Total | Demand Deviations | Supply Deviations | Generator Deviations | Deviations Total | Total |
| RTO (MWh) | 2,272,810 | 68,024 | 2,340,834 | 267,172 | 167,854 | 94,518 | 529,545 | 2,870,378 |
| RTO (Charges / Credits) | $46,803 | $1,401 | $48,204 | $1,431,209 | $899,176 | $506,323 | $2,836,708 | $2,884,912 |
| RTO (% of Total Charges) | 1.6% | 0.0% | 1.6% | 48.8% | 30.7% | 17.3% | 96.7% | 98.3% |
| East (MWh) | 1,265,989 | 31,282 | 1,297,271 | 144,841 | 97,216 | 61,408 | 303,465 | 1,600,736 |
| East (Charges / Credits) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| East (% of Total Charges) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| West (MWh) | 1,006,820 | 36,742 | 1,043,562 | 119,466 | 70,360 | 28,849 | 218,675 | 1,262,237 |
| West (Charges / Credits) | $28,708 | $1,048 | $29,756 | $10,308 | $6,071 | $2,489 | $18,868 | $48,624 |
| West (% of Total Charges) | 1.0% | 0.0% | 1.0% | 0.4% | 0.2% | 0.1% | 0.6% | 1.7% |
| Sum of Charges | $75,511 | $2,448 | $77,960 | $1,441,516 | $905,247 | $508,812 | $2,855,575 | $2,933,535 |

Table 3-56 shows that 61.9 percent of the balancing generator credits were paid to combustion turbines, 35.7 to combined cycles, and 2.3 percent to steam units for a total of $2,934,195. Cancellation and local constraint credits are not included in Table 3-55, but are included in balancing generator credits in Table 3-56, which accounts for the $660 difference.

*Table 3-56 Credits by operating reserve market (By unit type): March 3, 2009 (See 2008 SOM, Table 3-51)*

| Unit Type | Day-Ahead Generator | Synchronous Condensing | Balancing Generator | Lost Opportunity Cost |
|---|---|---|---|---|
| Combined Cycle | 78.0% | 0.0% | 35.7% | 0.8% |
| Combustion Turbine | 5.1% | 0.0% | 61.9% | 59.5% |
| Diesel | 0.0% | 0.0% | 0.1% | 0.0% |
| Hydro | 0.0% | 0.0% | 0.0% | 0.0% |
| Nuclear | 0.0% | 0.0% | 0.0% | 0.0% |
| Steam | 17.0% | 0.0% | 2.3% | 39.7% |
| Wind Farm | 0.0% | 0.0% | 0.0% | 0.0% |
| Total | $264,780 | $0 | $2,934,195 | $836,396 |

Table 3-57 shows the top 10 units in each category that received operating reserve credits. The amount of balancing generator credits paid to the top 10 units receiving balancing generator credits made up for about 50 percent of the total balancing generator credits, for a total of $1,483,757.

*Table 3-57 Top 10 units receiving operating reserve credits: March 3, 2009 (See 2008 SOM, Table 3-57 through Table 3-61)*

| Unit Rank | Day Ahead Generator Credit | Day Ahead Generator Credit Share | Day Ahead Generator Credit Cummulative Distribution | Day Ahead Generator Markup | Synchronous Condensing Credit | Synchronous Condensing Credit Share | Synchronous Condensing Credit Cummulative Distribution | Balancing Generator Credit | Balancing Generator Credit Share | Balancing Generator Credit Cummulative Distribution | Balancing Generator Markup | LOC Credit | LOC Credit Share | LOC Credit Cummulative Distribution | LOC Markup | Total Credit | Total Credit Share | Total Credit Cummulative Distribution |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $96,024 | 36.3% | 36.3% | 0.0% | $0 | 0.0% | 0.0% | $312,038 | 10.6% | 10.6% | 0.0% | $102,598 | 10.8% | 10.8% | 116.6% | $312,038 | 3.8% | 3.8% |
| 2 | $60,916 | 23.0% | 59.3% | 0.0% | $0 | 0.0% | 0.0% | $219,750 | 7.5% | 18.1% | 36.0% | $97,522 | 10.3% | 21.1% | 0.0% | $312,038 | 3.8% | 7.5% |
| 3 | $23,165 | 8.7% | 68.0% | 0.0% | $0 | 0.0% | 0.0% | $131,652 | 4.5% | 22.6% | 50.3% | $81,865 | 8.6% | 29.8% | 0.0% | $219,750 | 2.7% | 10.2% |
| 4 | $21,460 | 8.1% | 76.1% | 27.3% | $0 | 0.0% | 0.0% | $118,331 | 4.0% | 26.6% | 324.3% | $59,937 | 6.3% | 36.1% | 0.0% | $219,750 | 2.7% | 12.8% |
| 5 | $15,229 | 5.8% | 81.9% | 0.0% | $0 | 0.0% | 0.0% | $118,283 | 4.0% | 30.7% | 324.3% | $57,024 | 6.0% | 42.1% | 0.0% | $162,514 | 2.0% | 14.8% |
| 6 | $12,841 | 4.8% | 86.7% | 0.0% | $0 | 0.0% | 0.0% | $118,275 | 4.0% | 34.7% | 324.3% | $53,430 | 5.6% | 47.8% | 8.8% | $162,514 | 2.0% | 16.8% |
| 7 | $8,510 | 3.2% | 89.9% | 0.0% | $0 | 0.0% | 0.0% | $118,233 | 4.0% | 38.7% | 324.3% | $50,503 | 5.3% | 53.1% | 8.4% | $131,652 | 1.6% | 18.3% |
| 8 | $5,472 | 2.1% | 92.0% | 0.0% | $0 | 0.0% | 0.0% | $118,134 | 4.0% | 42.8% | 324.3% | $38,999 | 4.1% | 57.2% | 0.0% | $131,652 | 1.6% | 19.9% |
| 9 | $4,704 | 1.8% | 93.8% | 0.0% | $0 | 0.0% | 0.0% | $118,066 | 4.0% | 46.8% | 324.3% | $37,492 | 4.0% | 61.2% | 8.8% | $118,331 | 1.4% | 21.4% |
| 10 | $4,453 | 1.7% | 95.5% | 0.0% | $0 | 0.0% | 0.0% | $110,995 | 3.8% | 50.6% | 38.0% | $37,492 | 4.0% | 65.2% | 8.8% | $118,331 | 1.4% | 22.8% |

## Review of Impact on Regional Balancing Operating Reserve Charges

Total regional balancing generator credits for both reliability and deviation purposes for March 3, 2009 totaled $2,933,535.

*Table 3-58 Regional balancing operating reserve credits: March 3, 2009 (New Table)*

| | Reliability Credits | Deviation Credits | Total Credits |
|---|---|---|---|
| RTO | $48,204 | $2,836,708 | $2,884,912 |
| East | $0 | $0 | $0 |
| West | $29,756 | $18,868 | $48,624 |
| Total | $77,960 | $2,855,575 | $2,933,535 |

*Table 3-59 Total deviations: March 3, 2009 (New Table)*

| | Demand Deviations | Supply Deviations | Generator Deviations | Deviations Total |
|---|---|---|---|---|
| Total (MWh) | 267,172 | 167,854 | 94,518 | 529,545 |



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Under the old operating reserve construct, total credits (see Table 3-58) for the day would have been allocated to demand, supply, and generator deviations (see Table 3-59), resulting in the balancing rate of \$2,933,535 / 529,545 MWh = 5.5397 \$/MWh. This balancing rate would then have been applied to the sum of demand, supply, and generator deviations, summed across the entire RTO.

*Table 3-60 Charge allocation under old operating reserve construct: March 3, 2009 (New Table)*

| | Demand Deviations | Supply Deviations | Generator Deviations | Total |
|---|---|---|---|---|
| Total (MWh) | 267,172 | 167,854 | 94,518 | 529,545 |
| Balancing Rate ($/MWh) | 5.540 | 5.540 | 5.540 | 5.540 |
| Charges ($) | $1,480,060 | $929,867 | $523,605 | $2,933,532 |

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

For March 3, 2009, charges were actually allocated as shown in Table 3-61.

*Table 3-61 Actual regional credits, charges, rates and charge allocation MWh: March 3, 2009 (New Table)*

| | Reliability Charges | | | | Deviation Charges | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Reliability Credits ($) | RT Load and Exports (MWh) | Reliability Rate ($/MWh) | Reliability Charges ($) | Deviation Credits ($) | Deviations (MWh) | Deviation Rate ($/MWh) | Deviation Charges ($) | Total Charges ($) |
| RTO | $48,204 | 2,340,834 | 0.021 | $48,204 | $2,836,708 | 529,545 | 5.357 | $2,836,708 | $2,884,912 |
| East | $0 | 1,297,271 | 0.000 | $0 | $0 | 303,465 | 0.000 | $0 | $0 |
| West | $29,756 | 1,043,562 | 0.029 | $29,756 | $18,868 | 119,466 | 0.158 | $18,868 | $48,624 |
| Total | $77,960 | 2,340,834 | NA | $77,960 | $2,855,575 | 529,545 | NA | $2,855,575 | $2,933,535 |

The difference between the charges based on the old operating reserve construct (see Table 3-60) and the actual charges allocated under the current rules is shown in Table 3-62, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

*Table 3-62 Difference in total charges between old rules and new rules: March 3, 2009 (New Table)*

| | Reliability Charges | | | Deviation Charges | | | |
|---|---|---|---|---|---|---|---|
| | Real-Time Load | Real-Time Exports | Reliability Total | Demand Deviations | Injection Deviations | Generator Deviations | Deviations Total |
| Charges (Old) | $0 | $0 | $0 | $1,480,060 | $929,867 | $523,605 | $2,933,532 |
| Charges (Current) | $75,511 | $2,448 | $77,960 | $1,441,516 | $905,247 | $508,812 | $2,855,575 |
| Difference | $75,511 | $2,448 | $77,960 | ($38,543) | ($24,621) | ($14,793) | ($77,960) |

A breakdown of the reallocation of charges for the period January 2009 through June 2009 is shown in Table 3-63.

*Table 3-63 Difference in total charges between old rules and new rules: January through June 2009 (New Table)*

| | Reliability Charges | | | Deviation Charges | | | |
|---|---|---|---|---|---|---|---|
| | Real-Time Load | Real-Time Exports | Reliability Total | Demand Deviations | Injection Deviations | Generator Deviations | Deviations Total |
| Difference | $17,548,928 | $788,243 | $18,337,172 | ($9,518,775) | ($5,902,678) | ($2,915,720) | ($18,337,172) |

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