SECTION 3 – ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2008. 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, 2008 net revenue showed mixed results compared to 2007. For the new entrant combustion turbine (CT), all zones showed an increase in net revenue compared to 2007, which in many cases reflects lower energy revenue offset by increased capacity revenue. For the new entrant combined cycle (CC), all zones showed an increase in net revenue compared to 2007, which reflects an increase in energy and capacity market revenue in most eastern zones and an increase in just capacity market revenue in most western zones. For the new entrant coal plant (CP), most zones showed an increase in net revenue compared to 2007, which in many cases reflects lower energy market revenue offset by increased capacity market revenue. The levels of net revenue in 2008 for these new peaking, midmerit and coal-fired baseload power plants vary significantly by location. Higher energy market prices were offset by higher generation costs, and as a result, there were several zones for each technology that showed a decrease in energy market net revenue, despite higher price levels. However, revenues associated with the sale of capacity resources increased for all zones in 2008 as the Reliability Pricing Model (RPM) construct was in effect for a full calendar year. The fixed costs of constructing a combined-cycle generation resource were fully covered in some, but not all, PJM control zones. The fixed costs of constructing a combustion turbine were 99 percent covered by net revenues in AECO and Pepco Control Zones and 93 percent covered in the BGE Control Zone. There were no zones with revenue adequacy for the CP technology despite the full year of RPM capacity payments, as a result of increased fuel costs. The results from 2008 highlight the significance of the RPM construct's contribution to capital cost recovery and to the incentive to invest in new PJM generation resources in years when energy market and ancillary service revenues are inadequate to cover the costs of this investment.

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 2008 net revenue using PJM real-time average locational marginal prices (LMPs) was $50,532 per MW-year for a CT, the zonal maximum net revenue was $122,845 in the Pepco Control Zone and the minimum was $33,727 in the AEP Control Zone.[1] While the PJM average net revenue in 2008 was $103,928 per MW-year for a CC, the zonal maximum net revenue was $219,105 in the Pepco Control Zone and the minimum was $61,141 in the DLCO Control Zone. While the PJM average net revenue in 2008 was $218,144 per MW-year for a CP, the zonal maximum net revenue was $397,620 in the Pepco Control Zone and the minimum was $160,462 in the DAY Control Zone.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2008, PJM installed capacity resources rose slightly from 164,277 MW on January 1 to 164,895 MW on December 31.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2008, 40.7 percent was coal; 29.3 percent was natural gas; 18.5 percent was nuclear; 6.5 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste, and 0.1 percent was wind.

- **Generation Fuel Mix.** During 2008, coal provided 55.0 percent, nuclear 34.6 percent, gas 7.3 percent, oil 0.3 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.5 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 2008.** PJM did not declare a scarcity event in 2008.

- **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

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.

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.

  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 2008.** The level of operating reserve credits and corresponding charges decreased in 2008 by 6.5 percent compared to 2007. This was the result of a large decrease in the amount of synchronous condensing operating reserve credits, a smaller decrease in the amount of balancing operating reserve credits and an increase in the amount of day-ahead operating reserve credits.

- **New Operating Reserve Rules in 2008.** 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.

Conclusion

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

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

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

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 2008, market results were mixed. The cost of fuel inputs eroded the increased revenue from higher price levels, but that effect was less significant in some constrained eastern control zones. The result is that while the Energy Market Net Revenues alone are insufficient to recover capital costs in any control zone, when combined with RPM Capacity revenue, total net revenue in several eastern zones is sufficient to cover the investment costs of a new entrant combined cycle plant and total net revenue in three eastern zones are approximately sufficient to cover the investment costs of a new entrant combustion turbine.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2008. 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, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs. That is what occurred in 2008. The fixed costs of a CT in 2008 are substantially higher than the fixed costs of a CT in 2007, but the clearing prices in the Capacity Market reflect the prior, lower costs of a CT that were incorporated in the demand curve for the auctions that determined prices in the 2007/2008 and 2008/2009 RPM auctions.

The net revenue performance of combined cycle units (CCs) was significantly better than that of CTs. CCs, like CTs, burn gas but are more efficient than CTs and therefore as clearing prices set by CTs increase, net revenues from the Energy Market increase for CCs. These inframarginal energy revenues were the source of the higher CC net revenues in 2008.

Coal units (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 revenues as a result of CTs setting prices based on higher gas costs, when they run.

The ultimate test of a competitive market design is whether it provides incentives to invest that are acted upon by market participants, based on incentives endogenous to the competitive market design and not in reliance on the potential or actual exercise of market power. The net revenue performance of the Real-Time Energy Market, the Day-Ahead Energy Market and the Capacity Market prior to 2007 illustrated that additional market modifications were necessary if PJM were to pass that test. The performance of the markets in 2007 and 2008, especially the Capacity Markets, represented a significant improvement over prior performance. The reaction of investors will determine whether the market design modifications are successful.

Net Revenue

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 PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included when the analysis is based on perfect dispatch.[2] Operating reserve payments are included, when the analysis is based on the peak-hour, economic dispatch model on any days when a unit operated at a loss.[3]

Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity and Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after variable costs have been subtracted from gross revenue, to cover fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than on an analysis of actual net revenues for actual units operating in PJM. Energy Market net revenues were developed separately for both the Real-Time and the Day-Ahead Energy Markets.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2008 for the Real-

2 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over defined hours of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that, in contrast to the perfect dispatch model, considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

Time Energy Market and during 2000 to 2008 for the Day-Ahead Energy Market when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[4] For example, during 2008, if a unit had marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2008, adjusted for forced outages, it would have received $302,122 per installed MW-year in net revenue from the Real-Time Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $295,084 per installed MW-year in net revenue from the Day-Ahead Energy Market.[5]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2008.

Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2008

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984	$459,738
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397	$379,750
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215	$302,122
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918	$233,568
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033	$179,669
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768	$138,282
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644	$106,343
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859	$81,666
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467	$62,360
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110	$47,397
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898	$35,713
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655	$26,971
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795	$20,281
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737	$15,222
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302	$11,288
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202	$8,351
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357	$6,196
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722	$4,630
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219	$3,464
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831	$2,643

4 Real-Time and Day-Ahead Energy Market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since these tables include a range of marginal cost from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 marginal cost could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

5 This unit would not receive Real-Time Energy Market revenues in addition to Day-Ahead Energy Market revenues as any energy scheduled in the Day-Ahead Energy Market would be credited at the day-ahead energy market-clearing price and would not be eligible for Real-Time Energy Market revenues for the same hour of operation.

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2008.[6]

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2008

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007	2008
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734	$456,557
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295	$375,221
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702	$295,084
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320	$221,678
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297	$161,374
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674	$115,287
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135	$80,996
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326	$56,349
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257	$39,159
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530	$27,761
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730	$20,157
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081	$14,650
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167	$10,633
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703	$7,706
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421	$5,594
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241	$4,034
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118	$2,929
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51	$2,173
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11	$1,611
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0	$1,209

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve was higher in 2008 than in 2007 for every level of unit marginal costs up to and including $200 per MWh. For units with marginal costs equal to, or less than, $90, net revenues were higher in 2008 than in any other year since PJM introduced markets in 1999. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve was higher in 2008 than in 2007 for every marginal cost level up to and including $200. For units with marginal costs equal to, or less than, $130, net revenues were higher in 2008 than in any other year since PJM introduced the Day-Ahead Energy Market in 2000.

The increase in 2008 Real-Time Energy Market net revenue compared to 2007 is the result of changes in the frequency distribution of energy prices. In 2008, prices were greater than, or equal to, $30 per MWh more frequently than in 2007. The 2008 simple average LMP was $66.40 per MWh, a substantial increase compared to $57.58 per MWh in 2007. In 1999, the Real-Time Energy

6 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Market LMP was greater than, or equal to, $30 per MWh during 17 percent of all hours. In 2000, this was 29 percent; in 2001, 34 percent; in 2002, 30 percent; in 2003, 51 percent; in 2004, 68 percent; 81 percent in 2005; 74 percent in 2006; 79 percent in 2007, and 92 percent in 2008.

The increase in 2008 compared to 2007 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2008, prices were greater than, or equal to, $30 more frequently than in 2007 as the simple average LMP was $66.12 per MWh in 2008 compared to $54.67 per MWh in 2007. In 2000, the Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 42 percent of all hours. In 2001, this was 42 percent; in 2002, 33 percent; in 2003, 60 percent; in 2004, 72 percent; in 2005, 86 percent; in 2006, 80 percent; in 2007, 84 percent and in 2008, 96 percent.

The distribution of prices reflects a number of factors including load levels and fuel costs. Load levels in 2008 were close to those in 2007, while fuel costs increased significantly. An efficient CT could have produced energy at an average cost of $30 in 1999, compared to $90 in 2007 and $110 in 2008. An efficient CC could have produced energy at an average cost of $20 in 1999, compared to $55 in 2007 and $70 in 2008. An efficient CP could have produced energy at an average cost of $20 in 1999, but $25 in 2007 and $45 in 2008. Average price levels in 2008 were significantly higher than in 2007 and, as a result, net revenue levels were higher for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. However, these higher average price levels reflect higher costs associated with operating base-load, mid-merit and peaking generation resources, and Energy Market net revenues for a new entrant CT, CC and CP were mixed in 2008 despite higher PJM price levels. From 2007 to 2008, the average prices of natural gas and delivered coal increased more rapidly than did the PJM RTO average LMP. The result is that average PJM prices in 2008 were higher than they were in 2007, while natural gas-fired units and coal-fired units experienced relatively higher marginal costs compared to 2007, meaning lower energy net revenue in many control zones for 2008.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2008

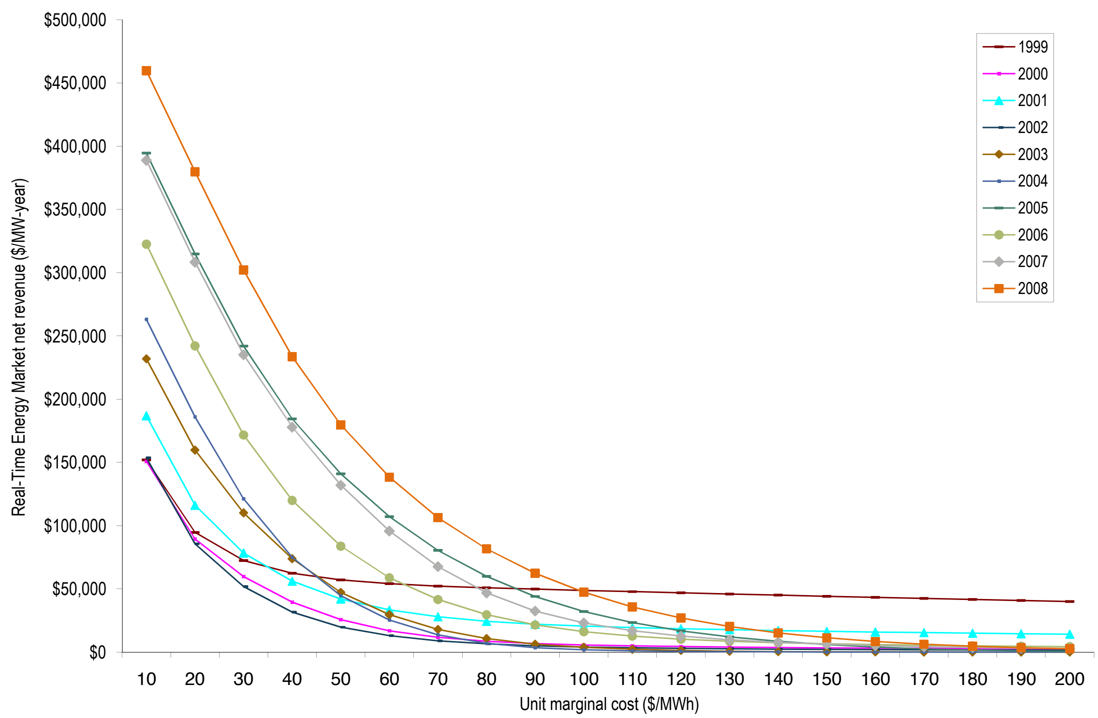
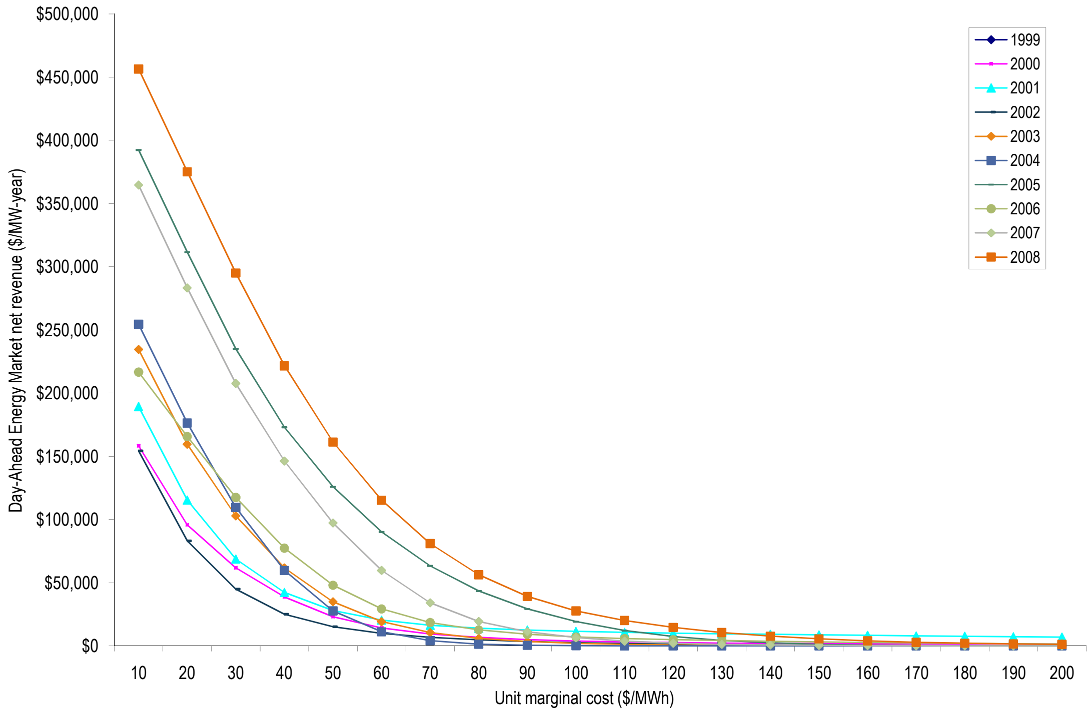


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2008



Differences in the shape and position of Real-Time and Day-Ahead Energy Market net revenue curves result from different distributions of Energy Market prices in each year. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[7]

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and therefore represent an upper bound of the direct contribution to generator fixed costs from the Energy Market. All other things constant, these Energy Market net revenues show how the frequency distribution of price levels in a given year affects the amount of revenue a generator would have received at the specified levels of marginal cost.

The Energy Market net revenues shown in Table 3-1 and Table 3-2 do not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC steam plant, a two-hour hot status notification plus startup time for a summer weekday could prevent a unit from running during two positive net revenue hours in the afternoon peak and two more positive net revenue hours in the evening peak separated by two negative net revenue hours, or could result in reduced net revenues from the negative net revenue hours.[8] The actual impact depends on the relationship between LMP and the operating cost of the unit. Similarly, a CP steam plant with an eight-hour cold status notification

7 See the *2008 State of the Market Report*, Volume II, Section 2, “Energy Market, Part 1,” at “Load and LMP” and Appendix C, “Energy Market” for detailed data on prices and their annual distribution.

8 A two-hour hot start, including a notification period, is consistent with the CC technology.

plus startup time could run overnight during negative net revenue hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[9] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. The Capacity Credit Market (CCM) design was in effect until June 1, 2007. For the period from January 1, through May 31, 2007, PJM capacity resources received a weighted-average payment from the CCM of $3.21 per MW-day of unforced capacity, a total of $485 per MW for the five-month period, or $1,172 per MW-year on an annualized basis. This is the lowest level of CCM revenues since the opening of the CCM in mid-1999.

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive a daily capacity payment of an amount determined by the first RPM Auction (June 1, 2007, through May 31, 2008) for their corresponding locational delivery area (LDA). For the first RPM Auction, there were three LDAs with three separate prices: RTO, which cleared at $40.80 per MW-day; Eastern Mid-Atlantic Area Council (EMAAC), which cleared at $197.67 per MW-day; and Southwestern Mid-Atlantic Area Council (SWMAAC), which cleared at $188.54 per MW-day. For the period January 1, 2008 through May 31, 2008, this revenue steam totaled $6,202 per MW in the RTO, $30,046 per MW in EMAAC and $28,658 per MW in SWMAAC. The second RPM auction clearing prices, applied from June 1, 2008 through December 31, 2008, were: $111.92 per MW-day for RTO or $23,951 per MW for the remainder of 2008, $148.80 per MW-day for EMAAC or $31,843 per MW for the remainder of 2008 and $210.11 per MW-day in SWMAAC or $44,964 for the remainder of 2008. Calendar year 2008 capacity revenues are a sum of five months or 152 days at the first auction clearing prices and seven months or 214 days at the second auction clearing prices. These revenues are shown by zone and LDA in Table 3-3.[10]

9 An eight-hour cold status notification plus startup is consistent with the CP technology.

10 Capacity revenues in Table 3-3 show total potential revenues available through RPM per installed MW-year and are not adjusted with a forced outage rate. Capacity revenues in Table 3-4 do reflect an adjustment for the system forced outage rate.

Table 3-3 2008 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2008

		Delivery Year 2007/2008		Delivery Year 2008/2009		
Zone	LDA	$/MW-Day	$/MW in 2007	$/MW-Day	$/MW in 2008	2008 Total
AECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
AEP	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
AP	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
BGE	SWMAAC	$188.54	$28,658	$210.11	$44,964	$73,622
ComEd	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DAY	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
Dominion	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DLCO	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DPL	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
JCPL	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
Met-Ed	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
PECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
PENELEC	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
Pepco	SWMAAC	$188.54	$28,658	$210.11	$44,964	$73,622
PPL	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
PSEG	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
RECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
PJM	N/A	$88.09	$13,390	$124.58	$26,660	$40,050

Table 3-4 shows zonal capacity revenue for the ten-year period 1999 to 2008.[11] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period.[12] Capacity revenue for 2008 reflects the first full year under the RPM construct, with five months of the first auction clearing price and seven months of the second auction clearing price.[13] These capacity revenues are adjusted for the yearly, systemwide forced outage rate.[14]

11 In tables with zonal net revenues, data for a transmission zone are displayed for all full calendar years following integration into PJM markets.

12 In Table 3-4, the 2007 column represents an average of all revenue associated with the sale of capacity by zone followed by a weighted-average of capacity revenue for the PJM footprint. The zonal results combine load-weighted averages from both daily and monthly CCM prices for January through May as well as the associated LDA-clearing price for the remaining seven months.

13 The 2007 total revenue associated with capacity for PJM in Table 3-4 similarly combines load-weighted CCM and RPM revenues. The RPM revenue for PJM in 2007 and 2008 is a load-weighted average based on all the LDA-clearing prices in Table 3-3 and the MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year throughout the PJM footprint, not exclusively the RTO LDA.

14 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-10, Table 3-12 and Table 3-14 as capacity revenues by technology type are adjusted for technology-specific outage rates.

Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$10,131
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$27,928	$9,109
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$20,605
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$27,928	$10,511
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$10,131
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$27,928	$12,812
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$10,131
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$13,647
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$13,647
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$20,605
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$13,647
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$18,915
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$37,095	$16,706

Ancillary Service and Operating Reserve Net Revenue

In addition to Capacity and Energy Market revenues, generators can receive revenue from the sale of ancillary services, including those from the Synchronized Reserve and Regulation Markets as well as from black start and reactive services. Aggregate ancillary service revenues, displayed for the years 1999 through 2008 in Table 3-5, were $4,970 per installed MW-year in 2008.[15] While actual, generator-specific ancillary service revenues vary with generator technology, ancillary service revenues are expressed here in terms of a system average per installed MW. New entrant net revenue calculations, addressed later in this section, use more detailed, technology-specific ancillary service estimates.

15 The 2007 value in Table 3-5 is different than the value initially published in the *2007 State of the Market Report*. See <http://www.MonitoringAnalytics.com/reports/PJM_State_of_the_Market/2007/2007-som-volume2-errata.pdf>.

Table 3-5 System average ancillary service revenue: Calendar years 1999 to 2008

	Dollars per Installed MW-Year
1999	$3,444
2000	$4,509
2001	$3,831
2002	$3,500
2003	$3,986
2004	$3,667
2005	$5,135
2006	$3,926
2007	$4,284
2008	$4,970

Generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $2,000 per installed MW-year in 2007 and were about $2,100 per installed MW-year in 2008. These payments are designed, in part, to ensure that generators are paid enough to cover their offers, including startup and no-load costs, when scheduled by PJM so that they are not required to run at a loss.

New Entrant Net Revenues

In order to provide a more realistic estimate of the net revenues that would result from investment in new generation resources, a peak-hour, economic dispatch scenario was analyzed. In contrast to the perfect dispatch scenario, economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology-specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NOx reduction. The CC plant consists of two GE Frame 7FA CTs with evaporative cooling, two heat recovery steam generators (HRSG) one for each CT and a single steam turbine generator. The HRSG is equipped with duct burners, intermediate pressure steam reheat and selective catalytic reduction (SCR) for NOx reduction. The coal plant is a western Pennsylvania steam CP, equipped with lime injection for SO_2 reduction and low NOx burners in conjunction with over fire air for NOx control.

All net revenue calculations include the use of actual hourly local ambient air temperature[16] and river water cooling temperature[17] and the effect of each, as applicable, on plant heat rates[18] and generator output for each of the three plant configurations.[19] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air and river condition variations.[20] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly. Available capacity is adjusted downward by the actual class average forced outage rate for each generator type in order to obtain the level of unforced capacity available for sale in PJM's Capacity Markets.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[21] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[22] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a continuous 15 day planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $6.47 per MWh for the CT plant, $2.80 per MWh for the CC plant and $3.00 per MWh for the CP plant. These estimates were provided by a consultant to the MMU and are based on quoted, third-party contract prices.[23] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[24] The delivered fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[25] Coal delivered cost was developed from the published prompt-month price, adjusted for rail transportation cost.[26] The average delivered fuel prices are shown in Table 3-6.

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. Steam units do provide Tier 1 synchronized reserve, but the 2008 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time ancillary service revenues for the provision of regulation were calculated for the CP plant. The

16 Hourly ambient conditions supplied by Meteorlogix for multiple points in PJM RTO. PJM net revenue calculations include the average of all points in PJM RTO. Zonal net revenue calculations include zone specific ambient air temperatures,

17 Hourly river water temperatures are estimated using local, zone specific ambient air conditions. The relationship between ambient air and local river temperatures is developed using data from the Philadelphia International Airport and the Reedy Island Jetty Gauge station located on the Delaware River. River data obtained from U.S. Department of the Interior, U.S. Geological Survey <http://nwis.waterdata.usgs.gov/pa/nwis/qwdata?site_no=01482800>.

18 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to the MMU, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for the MMU.

19 Pasteris Energy, Inc.

20 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, but is off for every uneconomic hour. Therefore, there is a single offer point and no offer curve.

21 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

22 Outage figures obtained from the PJM eGADS database.

23 Pasteris Energy, Inc.

24 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

25 Gas daily cash prices obtained from Platts.

26 Coal prompt prices obtained from Platts.

regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $7.50, per PJM market rules.[27] This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2008, for CTs, the calculated rate is $2,398 per installed MW-year; for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.[28]

Table 3-6 Average delivered fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2008

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74
2005	$9.73	$2.88
2006	$7.40	$2.68
2007	$7.87	$2.53
2008	$9.95	$4.60

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2008 is shown in Table 3-7, Table 3-8 and Table 3-9 for new entrant CT, CC and CP facilities, respectively. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP and delivered fuel costs.[29] The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

27 The adder was not adjusted to reflect the modifications to the regulation market rules that were effective on December 1, 2008.

28 The CT plant reactive revenues are based on 43 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 27 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on 18 recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2007 State of the Market Report* to include new generation filings.

29 Zonal net revenues for 2008 reflect the estimated average delivered fuel costs associated with each zone and increased locational fuel cost detail compared to 2007. As a result, changes from 2007 to 2008 zonal energy net revenue may reflect changes in estimated fuel costs in addition to changes in fuel price fundamentals.

Table 3-7 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 calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$65,046	$28,917
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$4,458	$3,924
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$17,701	$8,874
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$47,525	$27,031
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$4,886	$5,759
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$4,672	$3,896
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$43,465	$37,983
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$7,746	$5,906
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$35,422	$25,217
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$35,166	$24,048
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$25,498	$21,158
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$27,081	$21,481
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$5,953	$12,222
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$54,838	$28,753
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$21,531	$17,880
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$28,809	$22,855
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$23,966	$15,133
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$12,442	$16,005

Table 3-8 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 calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$154,085	$73,023
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$29,194	$23,353
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$68,874	$41,842
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$133,647	$67,478
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$30,764	$31,391
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$29,754	$22,839
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$123,330	$104,197
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$28,813	$22,761
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$117,134	$65,785
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$126,738	$65,389
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$99,239	$57,475
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$102,673	$58,627
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$44,971	$38,201
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$144,783	$70,027
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$92,238	$51,742
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$119,564	$67,947
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$108,670	$69,260
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$62,039	$46,167

Table 3-9 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$337,789	$192,824
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$152,316	$143,972
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$257,660	$192,356
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$309,846	$186,811
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$203,863	$152,444
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$130,757	$133,787
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$282,137	$278,007
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$138,614	$126,605
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$320,362	$188,607
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$315,991	$183,372
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$282,260	$173,429
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$290,745	$176,845
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$239,391	$149,074
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$328,211	$191,264
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$286,355	$167,152
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$248,728	$186,522
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$259,424	$234,413
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$179,457	$150,280

New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[30] for at least two hours during each four-hour block.[31] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve

30 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

31 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.[32]

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-10 for the years 1999 through 2008. This table shows the contribution of each market individually to the new entrant CT's total net revenue. The increase in capacity revenue is a result of a full year of RPM revenue.

Table 3-10 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2008

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532

Table 3-11 shows the total net revenue (the Total column in Table 3-10) for the new entrant CT in each zone.[33] For the ten-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $34,076 per installed MW-year.

32 The calculation of operating reserve payments does not reflect changes to operating reserves rules effective December 1, 2008.
33 New entrant CT zonal net revenue for 2008 reflects the estimated zonal, daily delivered price of natural gas.

Table 3-11 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$122,598	$49,856
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$33,727	$15,871
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$46,970	$19,731
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$115,532	$48,843
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$34,155	$18,096
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,046	$33,941	$15,843
Dominion	NA	NA	NA	NA	NA	NA	NA	$30,782	$53,923	$72,734	$52,480
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$9,360	$20,075	$37,015	$17,853
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$92,974	$46,155
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$92,718	$44,986
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$54,767	$36,313
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$84,633	$42,420
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,227	$35,222	$27,377
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,912	$122,845	$50,565
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$50,800	$33,036
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$86,361	$43,794
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$81,518	$35,307
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$50,532	$34,076

New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[34] If there were not eight economic hours in any given day, then the CC was not dispatched. For every hour the plant is dispatched, the applicable LMP is compared to the incremental costs of duct-firing, including fuel and, if applicable, emissions allowance credits.[35] If LMP is greater than or equal to the incremental costs of duct-firing for any hour the plant is operating, the duct burner is dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario

34 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

35 Duct-firing dispatch rate is developed using same methodology described for unfired dispatch rate, with temperature adjustments to duct-fired heat rate and output provided by Pasteris Energy, Inc.

uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-8 results.

Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-12 for the years 1999 through 2008. This table shows the contribution of each market individually to the new entrant CC's total net revenue. The increase in capacity revenue is a result of a full year of RPM revenue.

Table 3-12 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2008

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928

Table 3-13 shows the total net revenue (the Total column in Table 3-12) for the new entrant CC in each zone. For the ten-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $65,369 per installed MW-year.

Table 3-13 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$217,072	$95,343
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$61,521	$36,939
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$101,201	$54,087
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$207,969	$90,744
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$63,092	$45,405
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$62,081	$36,424
Dominion	NA	NA	NA	NA	NA	NA	NA	$83,104	$122,963	$155,658	$120,575
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$23,734	$44,520	$61,141	$36,346
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$143,274	$180,121	$88,106
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$189,725	$87,709
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$131,566	$73,499
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$165,660	$80,947
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$77,299	$54,225
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$219,105	$93,292
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$124,566	$67,765
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$182,551	$90,267
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$171,658	$91,617
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$103,928	$65,369

New Entrant Coal Plant

The new entrant CP Real-Time Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-14 for the years 1999 through 2008. This table shows the contribution of each market individually to the new entrant CP's total net revenue. The increase in capacity revenue is a result of the implementation of RPM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 3-14 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2008

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144

Table 3-15 shows the total net revenue (the Total column 7 in Table 3-14) for the new entrant CP in each zone.[36] For the ten-year period, the average total net revenue under the economic dispatch scenario was $170,294 per installed MW-year.

Table 3-15 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$118,254	$137,752	$143,257	$121,785	$179,117	$176,827	$306,995	$233,787	$345,739	$396,564	$216,008
AEP	NA	NA	NA	NA	NA	NA	$150,176	$127,588	$170,532	$182,201	$157,624
AP	NA	NA	NA	NA	$152,458	$123,620	$231,963	$178,701	$255,474	$288,025	$205,040
BGE	$115,926	$124,106	$116,306	$119,714	$173,476	$148,097	$303,218	$248,764	$380,425	$379,157	$210,919
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$234,487	$166,700
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,421	$160,462	$147,287
Dominion	NA	NA	NA	NA	NA	NA	NA	$240,828	$328,069	$312,361	$293,753
DLCO	NA	NA	NA	NA	NA	NA	$126,378	$108,418	$157,544	$168,837	$140,294
DPL	$121,871	$149,240	$164,219	$125,338	$179,145	$160,037	$287,243	$213,261	$339,158	$379,118	$211,863
JCPL	$117,958	$129,968	$133,853	$110,647	$165,730	$186,317	$290,747	$203,776	$352,520	$374,645	$206,616
Met-Ed	$116,776	$126,376	$126,885	$115,061	$167,368	$144,386	$276,296	$210,720	$311,760	$312,370	$190,800
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,382	$326,717	$349,522	$200,126
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,790	$269,748	$166,600
Pepco	$115,585	$123,766	$110,090	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$397,620	$215,416
PPL	$117,166	$125,227	$121,146	$105,991	$162,900	$136,365	$267,023	$201,584	$291,701	$316,263	$184,537
PSEG	$120,910	$145,675	$142,694	$112,410	$184,332	$189,717	$316,131	$224,904	$353,386	$307,268	$209,743
RECO	NA	NA	NA	NA	$186,860	$168,414	$298,796	$219,016	$347,309	$318,225	$256,437
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$218,144	$170,294

36 New Entrant CP zonal net revenue for 2008 incorporates the zone specific, delivered price of coal.

New Entrant Day-Ahead Net Revenues

In order to develop a comprehensive net revenue analysis, Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis.The results for the Day-Ahead Energy Market for each class are presented in Table 3-16, Table 3-17 and Table 3-18, respectively. [37]

Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$26,001	$15,118
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,827	$1,469
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$6,719	$4,307
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$27,271	$12,199
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$1,984	$2,115
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,628	$1,303
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$22,582	$16,217
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$1,428	$1,102
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$19,152	$13,580
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$14,163	$10,962
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$12,492	$10,502
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$12,688	$11,154
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$4,535	$5,932
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$32,677	$13,818
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$10,351	$8,591
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$13,686	$11,297
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$11,445	$6,264
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$6,623	$7,179

37 The Day-Ahead Energy Market net revenues were calculated utilizing the same fuel, weather and unit operational assumptions as were used for the Real-Time Energy Market net revenue calculations.

Table 3-17 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$115,974	$61,183
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$20,140	$15,628
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$50,885	$30,829
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$118,704	$53,077
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$24,163	$20,533
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$19,147	$14,071
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$101,261	$79,767
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$15,605	$12,381
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$101,261	$55,431
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$112,307	$54,013
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$84,379	$46,097
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$85,673	$49,026
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$39,701	$29,522
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$133,227	$57,219
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$77,511	$41,268
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$106,457	$57,033
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$96,618	$57,042
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$47,342	$33,588

Table 3-18 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$323,135	$195,320
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$149,397	$138,061
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$250,837	$184,355
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$312,579	$187,847
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$210,403	$150,457
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$123,738	$124,397
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$277,629	$261,111
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$139,537	$122,934
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$324,485	$196,744
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$320,484	$189,090
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$286,549	$178,934
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$297,666	$186,263
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$251,168	$155,417
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$333,200	$193,939
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$291,459	$174,072
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$250,151	$191,197
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$315,939	$235,041
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$174,191	$152,181

For the nine-year period, the average PJM Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario for the CT plant was $7,179 per installed MW-year. For the CC plant, the nine-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $33,588 per installed MW-year. For the CP plant, the eight-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $152,181 per installed MW-year.

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-19, Table 3-20 and Table 3-21 for the CT, CC and CP plants, respectively.

On average, the Real-Time Energy Market net revenue was 38 percent higher than the Day-Ahead Market net revenue for the CT plant, 21 percent higher for the CC plant and 3 percent higher for the CP.[38]

Table 3-19 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

	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%
Average	$11,605	$7,179	$4,426	38%

Table 3-20 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

	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%
Average	$42,347	$33,588	$8,759	21%

38 The Day-Ahead Energy Market was implemented on June 1, 2000. For the analysis presented in Table 3-19, Table 3-20 and Table 3-21, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-21 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

	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%
Average	$156,651	$152,181	$4,470	3%

Net Revenue Adequacy

To put the 2008 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2008.[39] The estimated, 20-year levelized fixed costs[40] are $123,640 per installed MW-year for the new entrant CT plant,[41] $171,361 per installed MW-year for the new entrant CC plant and $492,780 per installed MW-year for the new entrant CP plant.[42] Levelized fixed costs increased significantly for all three technologies. Table 3-22 shows the 20-year levelized costs for each technology for the period 2005 through 2008.[43] The increased costs of constructing generation facilities are the result of a combination of factors, including increased worldwide demand.

In this section, net revenue includes net revenue from the Real-Time Energy Market, from the Capacity Market and from any applicable ancillary service.

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

	2005	2006	2007	2008
	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	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

39 The MMU began evaluating fixed costs for all three technologies in 2005. In the following tables and figures, the 20-year levelized fixed costs from 2005 are used as a proxy for the preceding years.

40 Annual fixed costs may vary by location. The fixed costs presented here are associated with a location in the EMAAC LDA and are meant to serve as a baseline for comparison .

41 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

42 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2008.

43 The figures in Table 3-22 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Mid-Atlantic Region.

In 2008, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $50,532 per installed MW-year. The associated operating costs were between $110 and $120 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $9.95 per MBtu and a VOM rate of $6.47 per MWh.[44] The average PJM net revenue in 2008 would not have covered the fixed costs of a new CT. As shown in Table 3-23, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999, but zonal net revenues were sufficient to cover the fixed costs for a new CT in some cases.

Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
2008	$123,640	$50,532	41%
Average	$80,006	$34,076	43%

Table 3-24 includes the 20-year levelized fixed cost in 2008 for a new entrant CT, the economic dispatch net revenue for each zone in 2008 and average net revenue and average fixed costs for the period 1999 to 2008. While there are no control zones with net revenue sufficient to cover 100 percent of the 2008 levelized fixed costs, the net revenues in AECO of EMAAC LDA and Pepco control zones of the SWMAAC LDA are at 99 percent of the levelized fixed cost recovery and in BGE of the SWMAAC LDA, the net revenues are 93 percent of levelized fixed cost recovery. Figure 3-3 summarizes the information in Table 3-24, showing the 2008 average net revenue for a new entrant CT, the zonal net revenue for the period 1999 to 2008 and the levelized 2008 fixed cost for a new entrant CT. The extent to which net revenues cover the levelized fixed costs of investment in the CT technology is largely dependent on location, which affects both energy and, with the implementation of the RPM construct, capacity revenue. Figure 3-4 shows zonal net revenue for the new entrant CT by LDA with the applicable yearly levelized fixed costs for the period 1999-2008.

44 The analysis used the daily gas costs and associated production costs for CTs and CCs.

Table 3-24 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	2008			10-Year Average (1999-2008)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$122,598	$123,640	99%	$49,856	$80,006	62%
AEP	$33,727	$123,640	27%	$15,871	$80,006	20%
AP	$46,970	$123,640	38%	$19,731	$80,006	25%
BGE	$115,532	$123,640	93%	$48,843	$80,006	61%
ComEd	$34,155	$123,640	28%	$18,096	$80,006	23%
DAY	$33,941	$123,640	27%	$15,843	$80,006	20%
Dominion	$72,734	$123,640	59%	$52,480	$80,006	66%
DLCO	$37,015	$123,640	30%	$17,853	$80,006	22%
DPL	$92,974	$123,640	75%	$46,155	$80,006	58%
JCPL	$92,718	$123,640	75%	$44,986	$80,006	56%
Met-Ed	$54,767	$123,640	44%	$36,313	$80,006	45%
PECO	$84,633	$123,640	68%	$42,420	$80,006	53%
PENELEC	$35,222	$123,640	28%	$27,378	$80,006	34%
Pepco	$122,845	$123,640	99%	$50,565	$80,006	63%
PPL	$50,800	$123,640	41%	$33,036	$80,006	41%
PSEG	$86,361	$123,640	70%	$43,794	$80,006	55%
RECO	$81,518	$123,640	66%	$35,307	$80,006	44%
PJM	$50,532	$123,640	41%	$34,076	$80,006	43%

Figure 3-3 New entrant CT real-time 2008 net revenue, ten-year average net revenue and 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): Calendar years 1999 to 2008

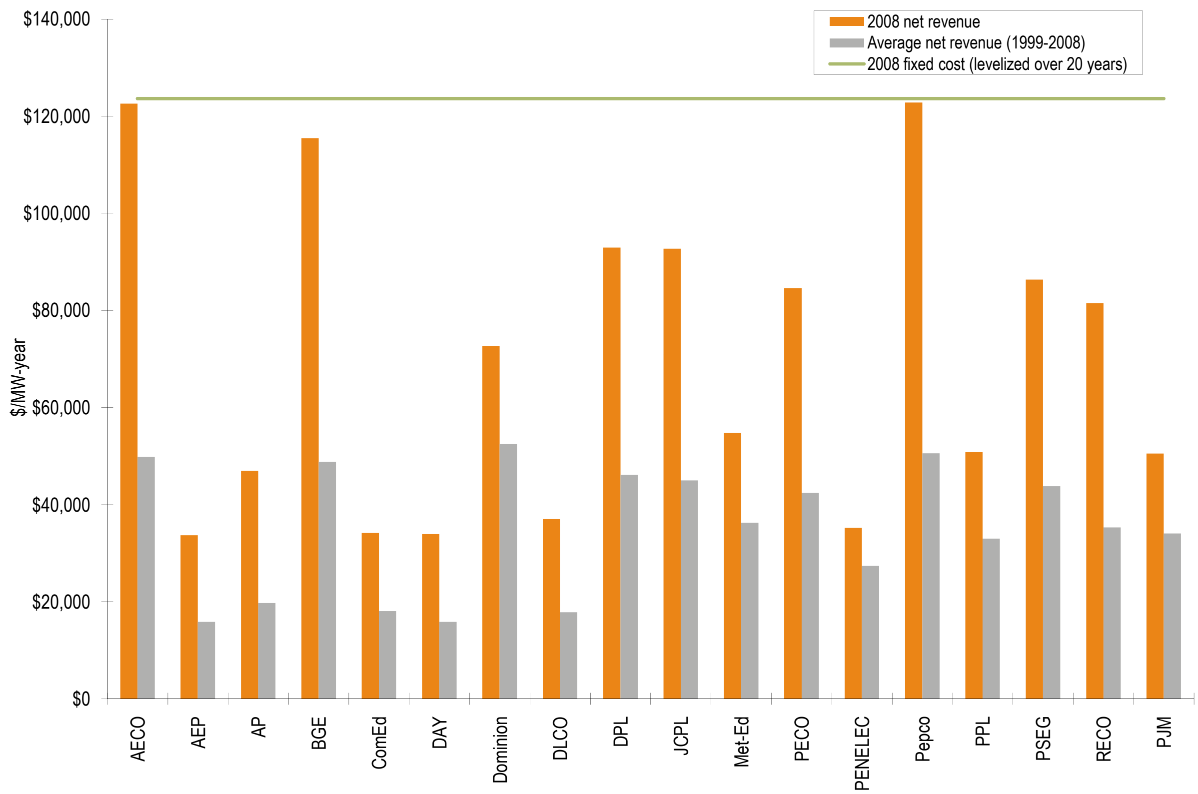
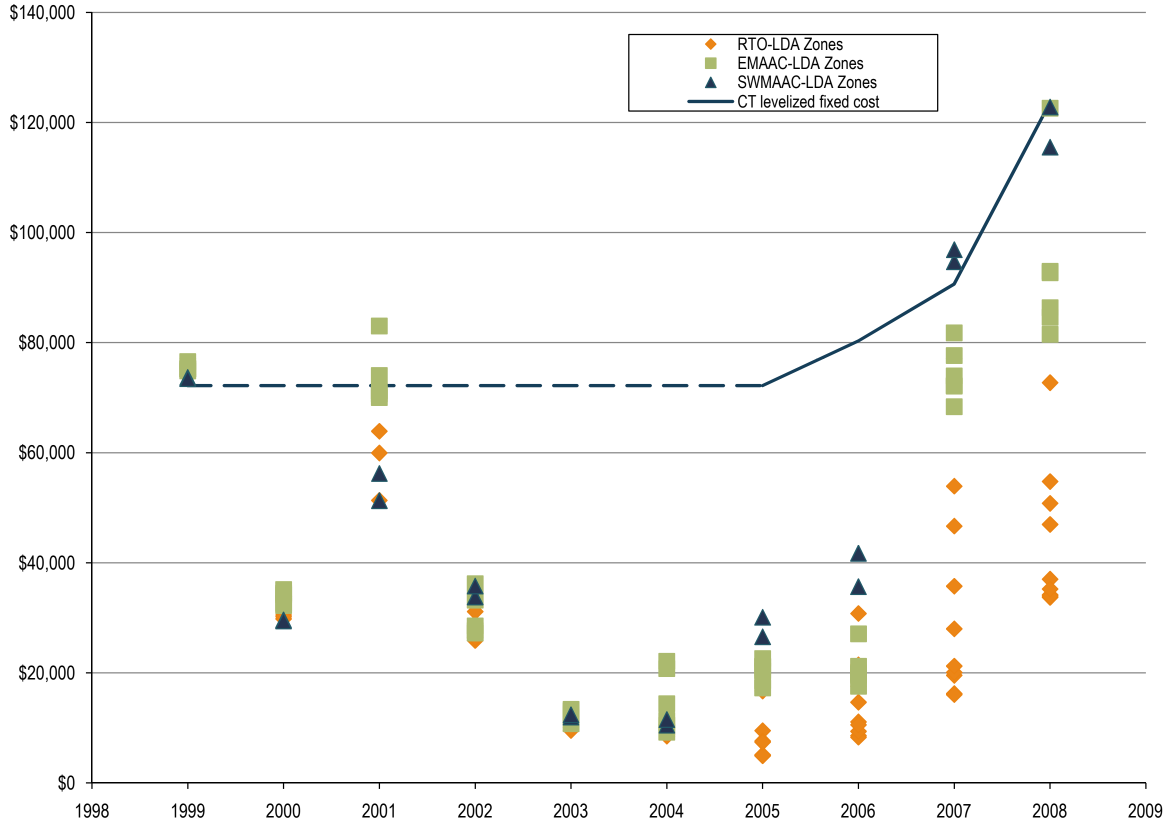


Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008



In 2008, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $103,928 per installed MW-year. The associated operating costs were between $70 and $80 per MWh, based on a design heat rate of 7,150 Btu per kWh, average daily delivered natural gas prices of $9.95 per MBtu and a VOM rate of $2.80 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-25 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2008. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999, but zonal net revenues were sufficient to cover the fixed costs for a new CC in some cases. Average 2008 net revenue for a CC is the highest since the opening of PJM markets.

Table 3-25 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
2008	$171,361	$103,928	61%
Average	$106,903	$65,369	61%

Table 3-26 compares the 20-year levelized fixed cost in 2008 for a new entrant CC to the economic dispatch net revenue for each zone in 2008, along with average net revenue for the period 1999 to 2008 and average fixed costs. While the average PJM net revenue is not enough to cover the levelized fixed costs, the net revenue for most EMAAC control zones and both SWMAAC control zones is more than sufficient in 2008 to cover the 20-year levelized fixed costs. Figure 3-5 summarizes the information in Table 3-26, showing the 2008 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2008 by zone and the levelized 2008 capital cost for a new entrant CC.[45] For every zone, 2008 net revenues for a CC are greater than the ten-year average as the result of increased capacity payments and higher zonal LMPs. The extent to which net revenues cover the levelized fixed costs of investment in the CC technology is largely dependent on location, which affects both energy and, with the implementation of the RPM construct, capacity revenue. Figure 3-6 shows zonal net revenue for the new entrant CC by LDA with the applicable yearly levelized fixed costs for the period 1999-2008.

45 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

Table 3-26 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	2008			10-Year Average (1999-2008)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$217,072	$171,361	127%	$95,344	$106,903	89%
AEP	$61,521	$171,361	36%	$36,939	$106,903	35%
AP	$101,201	$171,361	59%	$54,086	$106,903	51%
BGE	$207,969	$171,361	121%	$90,744	$106,903	85%
ComEd	$63,092	$171,361	37%	$45,405	$106,903	42%
DAY	$62,081	$171,361	36%	$36,424	$106,903	34%
Dominion	$155,658	$171,361	91%	$120,575	$106,903	113%
DLCO	$61,141	$171,361	36%	$36,346	$106,903	34%
DPL	$180,121	$171,361	105%	$88,106	$106,903	82%
JCPL	$189,725	$171,361	111%	$87,709	$106,903	82%
Met-Ed	$131,566	$171,361	77%	$73,498	$106,903	69%
PECO	$165,660	$171,361	97%	$80,947	$106,903	76%
PENELEC	$77,299	$171,361	45%	$54,225	$106,903	51%
Pepco	$219,105	$171,361	128%	$93,292	$106,903	87%
PPL	$124,566	$171,361	73%	$67,765	$106,903	63%
PSEG	$182,551	$171,361	107%	$90,267	$106,903	84%
RECO	$171,658	$171,361	100%	$91,617	$106,903	86%
PJM	$103,928	$171,361	61%	$65,369	$106,903	61%

Figure 3-5 New entrant CC real-time 2008 net revenue, ten-year average net revenue and 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): Calendar years 1999 to 2008

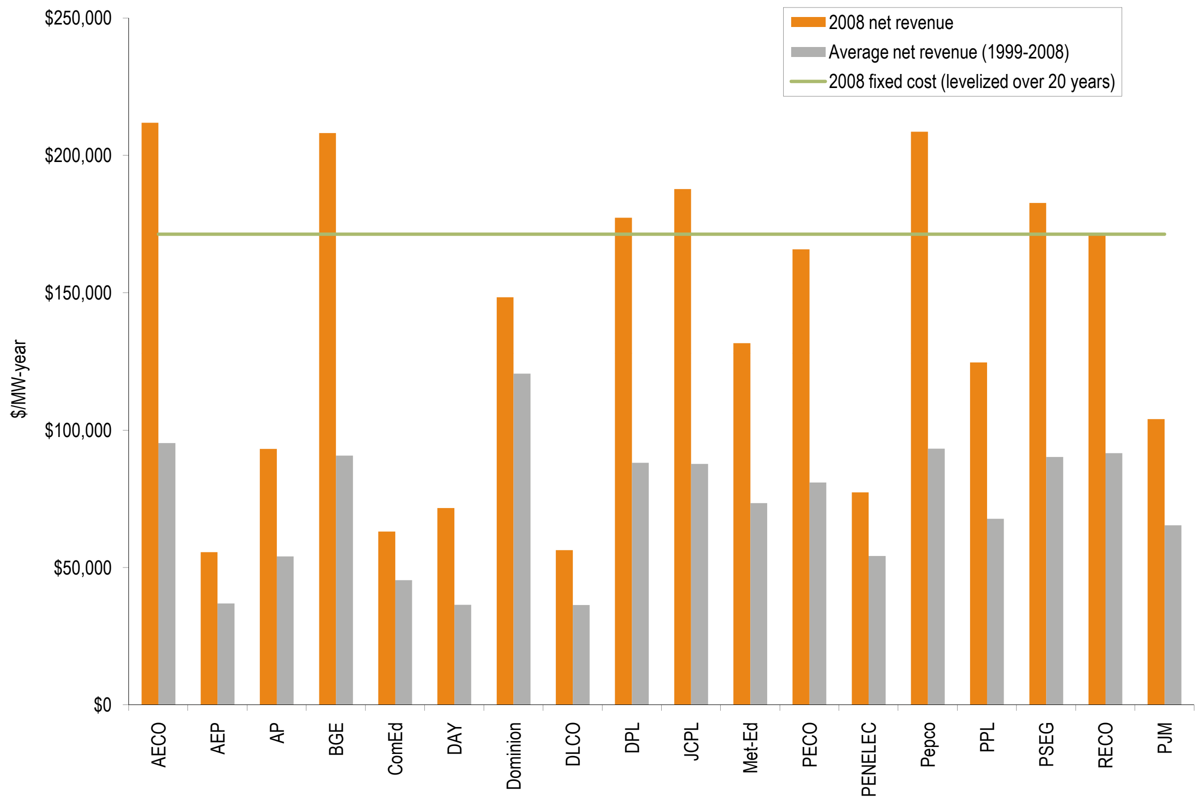


Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008

In 2008, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $216,929 per installed MW-year. The associated operating costs were between $40 and $50 per MWh, based on a design heat rate of 9,000 Btu per kWh, average delivered coal prices of $4.60 per MBtu and a VOM rate of $3.00 per MWh.[46] Table 3-27 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2008. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005, but zonal net revenues were sufficient to cover the fixed costs for a new CP in some cases. Average 2008 net revenue for a CP shows a significant decrease from 2007 reflecting the higher cost of coal.

46 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-27 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
2008	$492,780	$218,144	44%
Average	$231,697	$164,977	71%

Table 3-28 compares the 20-year levelized fixed cost in 2008 for a new entrant CP to the economic dispatch net revenue for each zone in 2008, along with average net revenue for the period 1999 to 2008 and average fixed costs. There were no control zones with sufficient net revenue to cover the 2008 levelized fixed costs. Figure 3-7 summarizes the information in Table 3-28, showing the 2008 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2008 by zone and the levelized 2008 capital cost for a new entrant CP.[47] For every zone, 2008 energy net revenues for a CP are lower than 2007, which is partially offset by higher capacity revenues.[48] The extent to which net revenues cover the levelized fixed costs of investment in the CP technology is largely dependent on location, which affects both energy and, with the implementation of the RPM construct, capacity revenue. Figure 3-8 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed costs for the period 1999-2008.

47 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

48 Average net revenues were taken for all years a zone was fully integrated into PJM.

Table 3-28 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	2008			10-Year Average (1999-2008)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$396,564	$492,780	80%	$216,008	$231,697	93%
AEP	$182,201	$492,780	37%	$157,624	$231,697	68%
AP	$288,025	$492,780	58%	$205,040	$231,697	88%
BGE	$379,157	$492,780	77%	$210,919	$231,697	91%
ComEd	$234,487	$492,780	48%	$166,700	$231,697	72%
DAY	$160,462	$492,780	33%	$147,287	$231,697	64%
Dominion	$312,361	$492,780	63%	$293,753	$231,697	127%
DLCO	$168,837	$492,780	34%	$140,294	$231,697	61%
DPL	$379,118	$492,780	77%	$211,863	$231,697	91%
JCPL	$374,645	$492,780	76%	$206,616	$231,697	89%
Met-Ed	$312,370	$492,780	63%	$190,800	$231,697	82%
PECO	$349,522	$492,780	71%	$200,126	$231,697	86%
PENELEC	$269,748	$492,780	55%	$166,600	$231,697	72%
Pepco	$397,620	$492,780	81%	$215,416	$231,697	93%
PPL	$316,263	$492,780	64%	$184,537	$231,697	80%
PSEG	$307,268	$492,780	62%	$209,743	$231,697	91%
RECO	$318,225	$492,780	65%	$256,437	$231,697	111%
PJM	$218,144	$492,780	44%	$170,294	$231,697	73%

Figure 3-7 New entrant CP real-time 2008 net revenue, ten-year average net revenue and 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): Calendar years 1999 to 2008

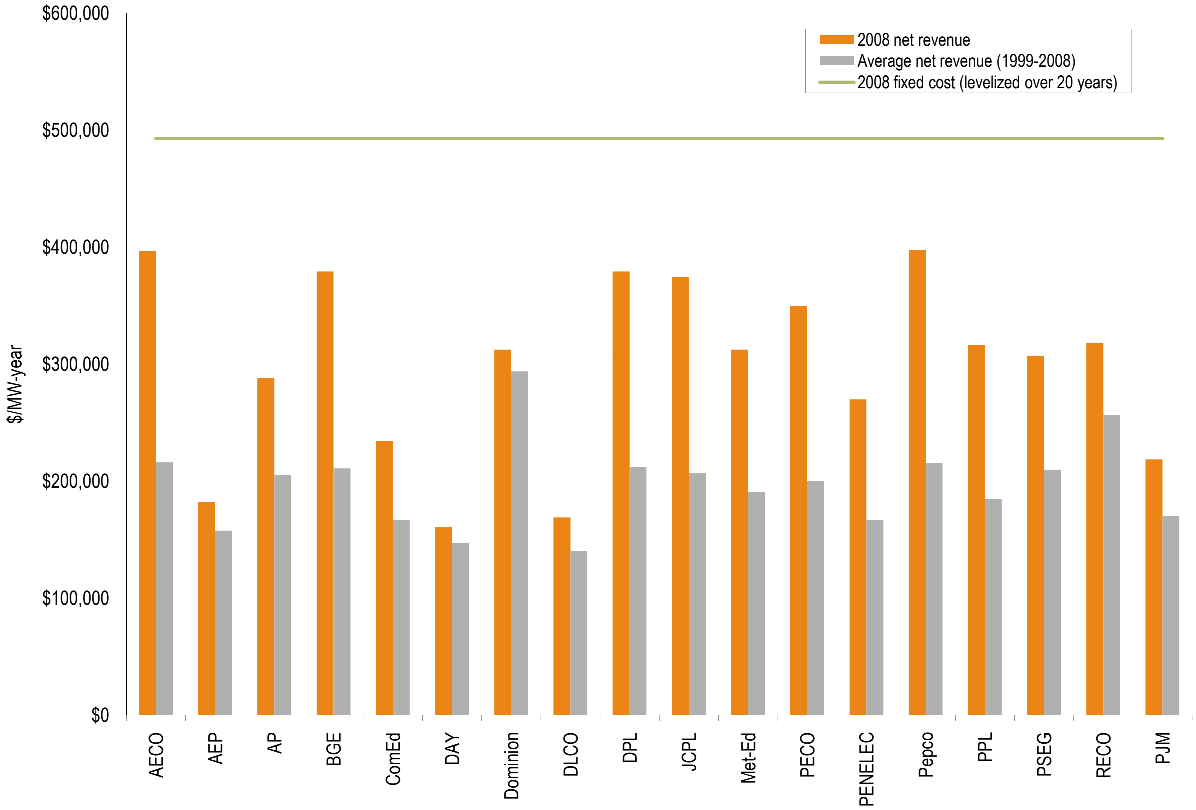
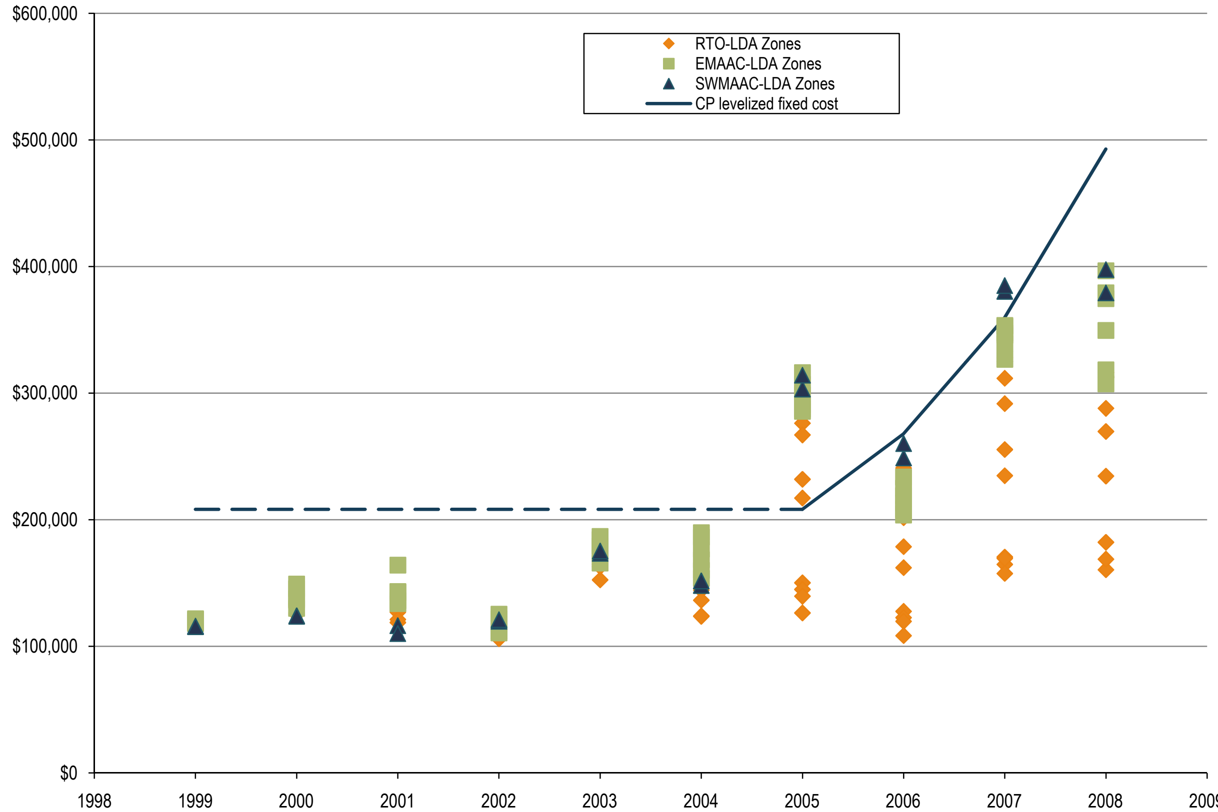


Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008



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. Analysis of 2008 net revenue indicates that the degree to which fixed costs of new peaking, midmerit and coal-fired baseload plants are covered depends on the location of the new plant, which affects both Energy Market net revenue and the Capacity Market net revenue resulting from the RPM. Additionally, the net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. As the delivered price of coal increased on average by about 82.1 percent, no control zones showed sufficient revenue to recover 20-year levelized capital costs in 2008.[49] While average natural gas prices increased by 26.4 percent, there were fewer hours of high demand and high price levels. As a result, Energy Market net revenue for a CT in most zones decreased which was partially offset by increased Capacity Market net revenue. While there are no control zones with net revenue sufficient to cover 100 percent of the 2008 levelized fixed costs, the net revenues in AECO of EMAAC LDA and Pepco control zones of the SWMAAC LDA are at 99 percent of the levelized fixed

49 The calculated increase in delivered cost of coal is based on Central Appalachian, low-sulfur coal used in PJM RTO net revenue calculations.

cost recovery and, in BGE of the SWMAAC LDA, the net revenues are 93 percent of levelized fixed cost recovery. Net revenue from the combined cycle technology was sufficient to recover the 20-year levelized fixed costs in a number of zones as a result of locational pricing in both the Energy and Capacity Markets.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2008. Scarcity revenues in the energy market also 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, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs. That is what occurred in 2008. The fixed costs of a CT in 2008 are substantially higher than the fixed costs of a CT in 2007, but the clearing prices in the Capacity Market reflect the prior, lower costs of a CT that were incorporated in the demand curve for the auctions that determined prices in the 2007/2008 and 2008/2009 RPM auctions.

The net revenue performance of combined cycle units (CCs) was significantly better than that of CTs. CCs, like CTs, burn gas but are more efficient than CTs and therefore as clearing prices set by CTs increase, net revenues from the Energy Market increase for CCs. These inframarginal energy revenues were the source of the higher CC net revenues in 2008.

Coal units (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 received higher net revenues as a result of CTs setting prices based on higher gas costs, when they ran. But these higher net revenues were offset by higher coal costs.

The returns earned by investors in generating units are a direct function of net revenues. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 3-22 . Levelized net revenues were modified and the IRR calculated. A $7,500 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $30,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-29.[50]

50 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 3-29 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$131,140	13.6%	$181,361	13.5%	$522,780	13.8%
Base Case	$123,640	12.0%	$171,361	12.0%	$492,780	12.0%
Sensitivity 2	$116,140	10.3%	$161,361	10.4%	$462,780	10.2%
Sensitivity 3	$108,640	8.6%	$151,361	8.8%	$432,780	8.2%
Sensitivity 4	$101,140	6.7%	$141,361	7.1%	$402,780	6.2%
Sensitivity 5	$93,640	4.7%	$131,361	5.3%	$372,780	3.9%
Sensitivity 6	$86,140	2.3%	$121,361	3.3%	$342,780	1.4%

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2008, PJM installed capacity rose slightly from 164,277 MW on January 1 to 164,895 MW on December 31, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2008, PJM installed capacity was 164,277 MW.[51] (See Table 3-30.) Over the next five months, unit retirements, facility reratings plus import and export shifts changed installed capacity to 163,752 MW on May 31, 2008.[52]

Table 3-30 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2008

	1-Jan-08		31-May-08		1-Jun-08		31-Dec-08	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,378	40.4%	66,334	40.5%	66,155	40.3%	67,065	40.7%
Oil	10,640	6.5%	10,638	6.5%	10,730	6.5%	10,715	6.5%
Gas	47,852	29.1%	47,728	29.1%	48,530	29.6%	48,340	29.3%
Nuclear	30,884	18.8%	30,884	18.9%	30,472	18.6%	30,468	18.5%
Solid waste	712	0.4%	712	0.4%	665	0.4%	665	0.4%
Hydroelectric	7,746	4.7%	7,391	4.5%	7,476	4.6%	7,476	4.5%
Wind	65	0.0%	65	0.0%	151	0.1%	166	0.1%
Total	164,277	100.0%	163,752	100.0%	164,179	100.0%	164,895	100.0%

51 Percents shown in Table 3-30 and Table 3-31 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
52 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.

At the beginning of the new planning year on June 1, 2008, installed capacity increased by 427 MW to 164,179 MW, a .26 percent increase in total PJM capacity over the May 31 level.

On December 31, 2008, PJM installed capacity was 164,895 MW.[53]

Energy Production by Fuel Source

In calendar year 2008, coal and nuclear units provided 89.6 percent, gas 7.3 percent, oil 0.3 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.5 percent of total generation.[54] (See Table 3-31.)

Table 3-31 PJM generation (By fuel source (GWh)): Calendar year 2008

	GWh	Percent
Coal	404,719.1	55.0%
Gas	53,552.4	7.3%
Hydroelectric	12,341.3	1.7%
Nuclear	254,379.2	34.6%
Oil	1,918.1	0.3%
Solar	0.0	0.0%
Solid Waste	5,020.8	0.7%
Wind	3,313.4	0.5%
Total	735,244.3	100.0%

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2008, 90,807 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 164,000 MW in 2008 and a year-end, installed capacity of 164,895 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000. (See Table 3-32.)

53 Wind-based resources accounted for 166.4 MW of installed capacity in PJM on December 31, 2008. 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 87 percent reduction. 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.

54 Gas includes landfill gas and natural gas.

Table 3-32 Year-to-year capacity additions: Calendar years 2000 to 2008

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

A more detailed examination of the queue data reveals some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west. The geographic distribution of units by fuel type in the queues, when combined with data on unit age, suggests that reliance on natural gas as a fuel in the east will increase.

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue U was active through January 31, 2008.

Capacity in generation request queues for the 11-year period beginning in 2008 and ending in 2018 increased by 25,853 MW from 64,954 MW in 2007 to 90,807 MW in 2008. (See Table 3-33.)[55, 56] Queued capacity scheduled for service in 2008 decreased from 11,636 MW to 7,037 MW, or 40 percent. Queued capacity scheduled for service in 2009 decreased from 10,377 MW to 9,023 MW, or 13 percent. Capacity in the queues for the years 2009 through 2014 increased in 2008 over 2007. Queued capacity scheduled for service in 2015 decreased from 3,234 MW to 2,436 MW, a decrease of 25 percent. Queued capacity scheduled for service in 2016 decreased from 1,640 MW to 0 MW. Queued capacity scheduled for service in 2018 increased from 0 MW to 1,594 MW.

55 See the *2007 State of the Market Report* (March 11, 2008), pp. 146-147, for the queues in 2007.

56 The 90,807 MW includes generation with scheduled in-service dates in 2008 and units still active in the queue with in-service dates scheduled before 2008, listed at nameplate capacity.

Table 3-33 Queue comparison (MW): Calendar years 2008 vs. 2007

	MW in the Queue 2007	MW in the Queue 2008	Year-to-Year Change (MW)	Year-to-Year Change
2008	11,636	7,037	(4,599)	(40)%
2009	10,377	9,023	(1,354)	(13)%
2010	11,464	18,052	6,588	57%
2011	17,653	17,253	(400)	(2)%
2012	5,520	15,527	10,007	181%
2013	1,660	7,920	6,260	377%
2014	1,770	11,965	10,195	576%
2015	3,234	2,436	(798)	(25)%
2016	1,640	0	(1,640)	(100)%
2018	0	1,594	1,594	NA
Total	64,954	90,807	25,853	40%

Table 3-34 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[57]

57 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

Table 3-34 Capacity in PJM queues (MW): At December 31, 2008 [58, 59]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,933	0	18,287	27,220
B Expired 31-Jan-99	0	4,613	0	15,882	20,495
C Expired 31-Jul-99	0	531	0	4,100	4,631
D Expired 31-Jan-00	0	768	0	7,069	7,836
E Expired 31-Jul-00	0	795	0	17,637	18,433
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	22,457	23,573
H Expired 31-Jan-02	0	560	143	8,422	9,124
I Expired 31-Jul-02	0	110	0	4,903	5,013
J Expired 31-Jan-03	0	36	0	862	898
K Expired 31-Jul-03	0	189	20	2,495	2,704
L Expired 31-Jan-04	20	256	165	3,849	4,290
M Expired 31-Jul-04	0	204	293	4,084	4,581
N Expired 31-Jan-05	790	2,168	97	6,648	9,703
O Expired 31-Jul-05	2,589	509	409	3,865	7,372
P Expired 31-Jan-06	4,266	709	1,625	2,242	8,842
Q Expired 31-Jul-06	6,782	669	2,423	5,457	15,331
R Expired 31-Jan-07	10,095	614	106	12,007	22,822
S Expired 31-Jul-07	12,190	530	222	7,967	20,909
T Expired 31-Jan-08	23,564	106	142	2,166	25,978
U Expired 31-Jan-09	24,229	20	8	0	24,256
Total	84,524	22,857	6,283	153,491	267,156

Data presented in Table 3-34 show that 59 percent of total in-service capacity from all the queues was from Queues A and B and an additional 9 percent was from Queues C, D and E.[60]

The data presented in Table 3-35 show that for successful projects there is an average time of 700 days (i.e., 1.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 541 days (i.e., 1.5 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

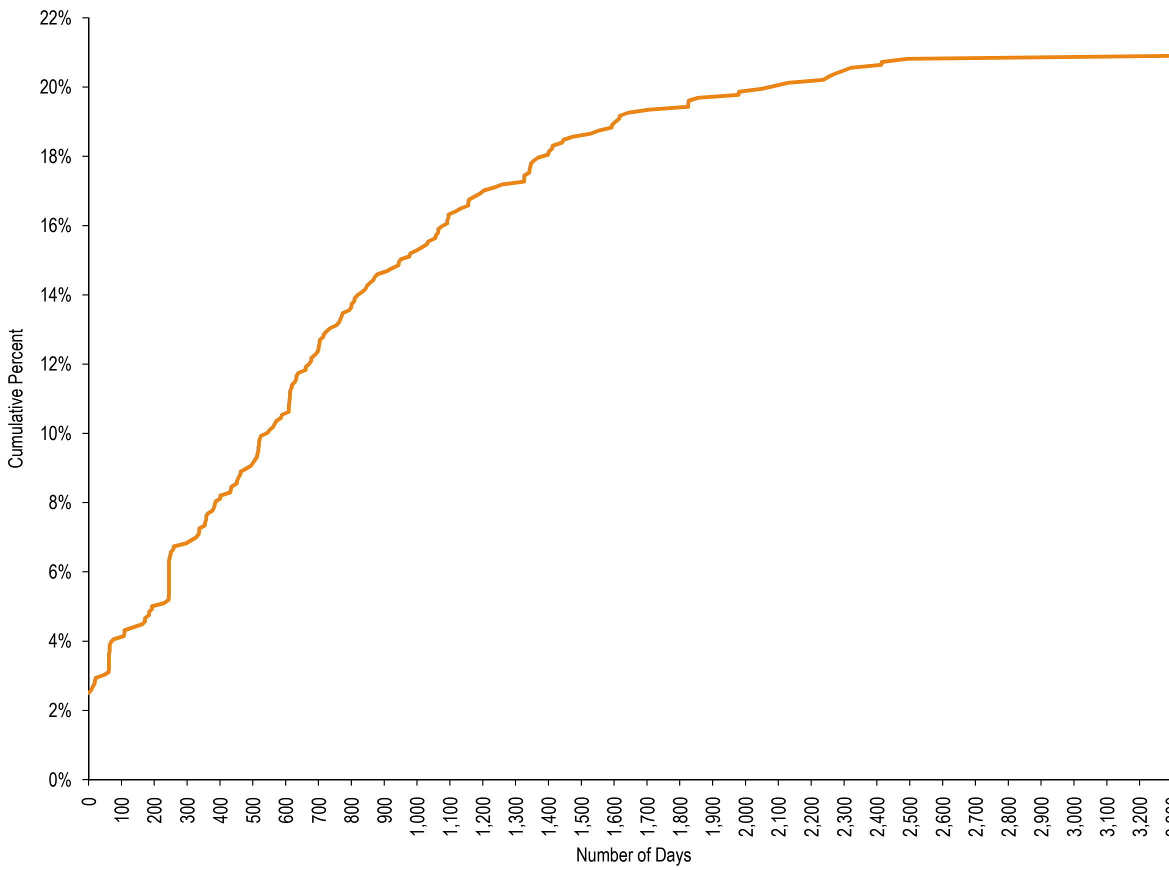
Table 3-35 Average project queue times: At December 31, 2008

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In-Service	700	626	0	3287
Under Construction	1,132	984	0	4370
Withdrawn	541	565	0	2710
Active	1,069	633	0	3390

58 The *2008 State of the Market Report* contains all projects in the queue including reratings of existing generating units and energy only resources.
59 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
60 The data for Queue U include projects through December 31, 2008

Figure 3-9 shows the cumulative probability of completion of RTEP projects. The first queue (Queue A) was opened more than 4,000 days ago and the final active project in the A Queue was completed in 2006. The final project was in the queue for 3,287 days and this is the upper limit of Figure 3-9. The data show that about 10.0 percent of all projects in the queue are completed within 546 days and about 20.8 percent of the projects are completed within 3,287 days.

Figure 3-9 RTEP project completion probability as function of days in queue



Distribution of Units in the Queues

Table 3-36 shows the RTEP projects under construction or active as of December 31, 2008, by unit type and control zone. Most (90.2 percent of the MW) of the steam projects (predominantly coal) and most of the wind projects (93.3 percent of the MW) are outside the Eastern MAAC (EMAAC)[61] and Southwestern MAAC (SWMAAC)[62] locational deliverability areas (LDAs).[63] Much (44 percent of the MW) of the combined-cycle projects are in EMAAC and SWMAAC. Wind projects account for approximately 43,784 MW of capacity or 48 percent of the capacity in the queues and CC

61 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones.

62 SWMAAC consists of the BGE and Pepco control zones.

63 See the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

projects account for 22,724.1 MW of capacity or 25 percent of the capacity in the queues.[64] Of the total capacity additions, only about 16,847 MW or 18.5 percent are projected to be in zones that are in EMAAC; about 3,536.5 MW or 3.9 percent are projected to be constructed in zones that are in SWMAAC.

Table 3-36 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2008

	CC	CT	Diesel	Hydro	Nuclear	Steam	Wind	Unknown	Total
AECO	440	956	7	0	0	670	1,416	0	3,489
AEP	1,035	594	185	150	84	3,728	7,130	0	12,906
AP	1,300	606	6	210	0	1,478	2,095	0	5,695
BGE	100	335	4	0	0	0	0	0	439
ComEd	1,300	851	94	0	298	726	27,243	44	30,556
DLCO	0	0	0	87	75	0	0	0	162
DPL	0	284	0	0	0	23	1,500	30	1,837
DAY	0	10	2	0	0	12	847	0	871
Dominion	3,613	998	21	94	1,944	326	230	169	7,395
JCPL	2,750	40	30	1	0	15	0	0	2,836
Met-Ed	2,595	1,032	49	0	24	0	0	0	3,700
ODEC	0	9	0	0	0	0	0	0	9
PECO	3,180	595	0	0	140	21	0	0	3,936
PENELEC	0	161	6	32	0	350	2,697	0	3,245
Pepco	1,195	239	4	0	1,640	0	0	20	3,098
PPL	2,836	112	23	143	1,707	149	626	153	5,748
PSEG	2,380	1,254	67	1,000	43	0	0	0	4,744
RECO	0	6	0	0	0	0	0	0	6
UGI	0	135	0	0	0	0	0	0	135
Total	22,724	8,216	499	1,715	5,955	7,499	43,784	416	90,807

Table 3-37 shows existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across control zones.

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 (Table 3-36) 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 CC and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely.

64 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent. Based on the derating of 43,784 MW of wind resources, the 90,807 MW currently active in the queues would be reduced to 55,132 MW.

Table 3-37 Existing PJM capacity 2008 (By zone and unit type (MW))

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	17	0	0	1,108	8	1,816
AEP	4,272	2,773	0	1,011	2,093	21,015	0	31,164
AP	1,129	264	43	80	0	7,878	81	9,475
BGE	0	872	0	0	1,735	2,897	0	5,504
ComEd	1,790	6,404	0	0	11,448	7,094	734	27,470
DAY	0	1,316	44	0	0	4,805	0	6,165
DLCO	272	45	0	0	1,630	3,524	0	5,471
DPL	1,088	801	88	0	0	1,825	0	3,802
Dominion	2,515	3,226	105	3,321	3,459	8,342	0	20,968
External	0	0	6	0	0	5,645	0	5,652
JCPL	770	1,224	13	400	619	10	0	3,036
Met-Ed	1,370	417	0	19	786	819	0	3,411
PECO	2,497	1,503	6	1,618	4,492	2,022	0	12,138
PENELEC	0	332	35	495	0	6,805	119	7,786
Pepco	1,134	1,317	0	0	0	4,781	0	7,232
PPL	1,674	462	34	568	2,289	5,515	113	10,655
PSEG	2,933	2,993	21	11	3,353	2,279	0	11,590
Total	21,599	24,477	411	7,523	31,904	86,364	1,055	173,334

Table 3-38 shows the age of PJM generators by unit type. If the age profile of steam units in PJM accurately represents the future age profile, significant and disproportionate retirements of steam units will occur within the next 10 to 20 years. While steam units comprise 49.8 percent of all current MW, steam units 40 years of age and older comprise 86.7 percent of all MW 40 years of age and older and nearly 96.7 percent of such MW if hydroelectric is excluded from the total. Approximately 6,461 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC.

Table 3-38 PJM capacity age (MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Less than 10	16,061	14,337	98	122	0	1,281	1,055	32,954
10 to 20	4,978	2,977	76	55	3,533	7,109	0	18,729
20 to 30	0	86	56	3,112	14,914	9,090	0	27,258
30 to 40	560	6,173	87	703	13,457	39,267	0	60,247
40 to 50	0	904	91	2,217	0	20,186	0	23,398
50 to 60	0	0	4	354	0	9,267	0	9,625
60 to 70	0	0	0	107	0	164	0	271
70 to 80	0	0	0	553	0	0	0	553
80 to 90	0	0	0	138	0	0	0	138
90 to 100	0	0	0	132	0	0	0	132
100 and over	0	0	0	29	0	0	0	29
Total	21,599	24,477	411	7,523	31,904	86,364	1,055	173,334

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-39 shows that in the EMAAC LDA, gas-consuming unit types dominate the capacity additions, accounting for approximately 70.5 percent of the slated capacity additions. Steam additions (coal) account for about 4.3 percent of the MW and wind projects account for 17.3 percent of the MW in the queue for the EMAAC LDA. It should be noted that the wind capacity in Table 3-39 is reported at nameplate capacity and not reduced to 20 percent of nameplate. Nuclear and gas capacity comprise 99.2 percent of the MW capacity additions in the SWMAAC LDA.

Table 3-39 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2008

	CC	CT	Diesel	Hydro	Nuclear	Steam	Wind	Unknown	Total
EMAAC	8,750	3,134	104	1,001	183	730	2,916	30	16,847
Non-MAAC	7,248	3,203	309	540	2,401	6,270	37,545	213	57,729
SWMAAC	1,295	574	8	0	1,640	0	0	20	3,537
WMAAC	5,431	1,305	78	175	1,731	499	3,323	153	12,694
Total	22,724	8,216	499	1,715	5,955	7,499	43,784	416	90,807

Table 3-40 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. In 2018, CC and CT generators would account for 57.3 percent of EMAAC generation, an increase of 12.5 percentage points from 2008 levels. Accounting for the fact that about 1123 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 44.8 percent to about 57 percent. This proportion of gas-fired capacity in EMAAC would increase to 60.4 percent if the 80 percent reduction for wind capacity is taken into account for EMAAC, meaning that the effective capacity additions are 14,508 MW.

The exact expected role of gas-fired generation depends largely on projects in the queues. There is a planned addition of 1640 MW of nuclear capacity in SWMAAC.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 74 percent of all new capability in EMAAC and 86 percent when the 80 percent reduction for wind capability is included. In 2018 this would mean that CC and CT generators would comprise 61.4 percent of total capability in EMAAC.

Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent nearly 100 percent of all new capability in the SWMAAC. In 2018 this would mean that CC and CT generators would comprise 43.8 percent of total capability in SWMAAC.

Table 3-40 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018 [65]

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	Combined cycle	0	0.0%	7,443	23.0%	8,750	16,193	36.0%
	Combustion turbine	620	10.3%	7,049	21.8%	3,134	9,563	21.3%
	Diesel	36	0.6%	144	0.4%	104	212	0.5%
	Hydroelectric	1,750	29.2%	2,029	6.3%	1,001	3,030	6.7%
	Nuclear	0	0.0%	8,464	26.1%	183	8,647	19.2%
	Steam	3,593	59.9%	7,244	22.4%	730	4,381	9.7%
	Wind	0	0.0%	8	0.0%	2,916	2,924	6.5%
	Unknown	0	0.0%	0	0.0%	30	30	0.1%
	EMAAC Total	5,999	100.0%	32,381	100.0%	16,847	44,979	100.0%
Non-MAAC	Combined cycle	0	0.0%	9,978	9.4%	7,248	17,226	12.0%
	Combustion turbine	27	0.1%	14,028	13.2%	3,203	17,204	11.9%
	Diesel	39	0.2%	198	0.2%	309	468	0.3%
	Hydroelectric	1,338	6.3%	4,412	4.1%	540	4,952	3.4%
	Nuclear	0	0.0%	18,630	17.5%	2,401	21,031	14.6%
	Steam	19,956	93.4%	58,303	54.8%	6,270	44,617	31.0%
	Wind	0	0.0%	815	0.8%	37,545	38,360	26.6%
	Unknown	0	0.0%	0	0.0%	213	213	0.1%
	Non-MAAC Total	21,360	100.0%	106,365	100.0%	57,729	144,072	100.0%
SWMAAC	Combined cycle	0	0.0%	1,134	8.9%	1,295	2,429	18.2%
	Combustion turbine	59	2.0%	2,189	17.2%	574	2,704	20.3%
	Diesel	0	0.0%	0	0.0%	8	8	0.1%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,735	13.6%	1,640	3,375	25.3%
	Steam	2,868	98.0%	7,678	60.3%	0	4,810	36.0%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	Unknown	0	0.0%	0	0.0%	20	20	0.1%
	SWMAAC Total	2,927	100.0%	12,736	100.0%	3,537	13,346	100.0%
WMAAC	Combined cycle	0	0.0%	3,044	13.9%	5,431	8,475	27.2%
	Combustion turbine	198	5.1%	1,211	5.5%	1,305	2,318	7.4%
	Diesel	20	0.5%	69	0.3%	78	127	0.4%
	Hydroelectric	443	11.5%	1,082	5.0%	175	1,257	4.0%
	Nuclear	0	0.0%	3,075	14.1%	1,731	4,806	15.4%
	Steam	3,200	82.9%	13,139	60.1%	499	10,438	33.5%
	Wind	0	0.0%	232	1.1%	3,323	3,555	11.4%
	Unknown	0	0.0%	0	0.0%	153	153	0.5%
	WMAAC Total	3,861	100.0%	21,852	100.0%	12,694	31,128	100.0%
All Areas	Total	34,147		173,334		90,807	233,525	

65 Percents shown in Table 3-40 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Scarcity and Scarcity Pricing

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.

The energy market can and should be competitive. A competitive market clears based on the marginal cost of the highest cost unit that is producing energy, accounting for the possibility of multiple marginal units in the presence of transmission constraints. There is no reason to build market power into the design of the energy markets. A complete market design will provide adequate revenues via scarcity revenues in an energy only market or via scarcity revenues provided in the form of capacity payments in a hybrid market design.

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.

In 2005, prior to the introduction of the RPM capacity market design, it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for non market emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administrative scarcity pricing mechanism.[66] The scarcity pricing settlement

66 See the *2005 State of the Market Report*, "Scarcity" (March 8, 2006), pp. 145-150.

was an effort to address the revenue adequacy and incentive issues in PJM markets in the absence of a capacity market design that reflected the full costs of capacity.

PJM members entered into a settlement in 2005 that was approved by the FERC and resulted in the implementation of administrative scarcity pricing rules in 2006.[67] August 8, 2007, was the first time that the administrative scarcity pricing rules were triggered. PJM did not declare a scarcity pricing event in 2008.

PJM's current administrative scarcity pricing mechanism was designed to provide an appropriate tradeoff between limiting local market power and allowing market prices to reflect scarcity conditions in the absence of the RPM capacity market design.[68] The administrative rules initiate scarcity pricing when PJM takes specific, non market, emergency administrative actions to maintain system reliability under conditions of high load in defined areas within PJM. These emergency actions include emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events. When PJM implements any of the identified emergency procedures, offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

PJM's current scarcity pricing rules have been invoked only once. These rules have not and will not have a significant impact on generator revenues. However, that is irrelevant given the development of the RPM capacity market design. With a properly defined revenue offset, the introduction of improved scarcity pricing measures in PJM markets will affect the incentives of a very limited set of PJM resources. Scarcity pricing will generally not affect the incentives of either generation or load that has committed in the Day-Ahead Energy Market. Scarcity pricing will affect the incentives of load at the margin on high load days. Scarcity pricing will affect the incentives of external resources to sell power to PJM markets. Scarcity pricing will affect the incentives of DSR providers and users at the margin. Modifications to scarcity pricing will improve the functioning of PJM markets but they will, if properly designed, not have a large impact on revenues for most generators or charges for most loads.

Scarcity Pricing Issues

Scarcity exists when the total demand for power approaches the generating capability of the system. Scarcity pricing means that market prices reflect the fact that the system is close to its available capacity. Under scarcity conditions, competitive prices may exceed short-run marginal costs. Under the current PJM rules, high prices result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[69] As demand increases and units with higher offers are required to meet demand, prices increase. This dynamic may be limited if all units with high offers are subject to offer capping for local market power. In that case, an explicit decision to lift offer capping must be based on a determination that scarcity exists in a defined area. Under the scarcity pricing provisions in the tariff, that determination is made when PJM takes identified

67 114 FERC ¶ 61,076 (2006).
68 114 FERC ¶ 61,076 (2006).
69 See the *2008 State of the Market Report*, Volume II, Section 2. at "Market Structure."

emergency actions. Scarcity pricing results, with the scarcity price based on the highest offer of an operating unit.

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 scarcity rents in the energy market as an offset to capacity market offers, 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.

The challenge is to translate these basic guidelines about scarcity pricing into a consistent set of market rules. The MMU recommendations regarding scarcity pricing represent a step toward defining market rules.

While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, there are indications, based on the MMU analysis of 2007 market results, that PJM's current set of scarcity pricing rules need refinement.[70] While PJM did declare a scarcity pricing event in 2007, prior to that declaration PJM was able to use emergency resources to meet operational goals, declaring a maximum emergency alert, which resulted in the inclusion of maximum emergency generation resources in operational reserve and the calling of emergency demand-response resources, without triggering a scarcity event. Had the use of emergency demand-response resources been a trigger, the scarcity event would have started earlier and ended later than it did in 2007.

It is also not clear that a reliance on emergency steps as a trigger for scarcity, and the simple removal of offer caps based on that trigger, is the most effective and efficient way to recognize and reflect scarcity in a least cost, security constrained dispatch based market.

Definitions and Methodology

Scarcity can be defined to exist when demand, including an operating reserve target, is greater than, or equal to, available supply excluding the impact of non market administrative intervention. Scarcity can exist at varying levels of severity, reflected by the degree to which load plus the reserve requirement exceeds supply, excluding the impact of non market administrative actions. The more emergency resources and actions that are needed to maintain system reliability, the more severe the scarcity event.

70 PJM did not declare a scarcity event in 2008.

Relevant operating reserve targets are an essential component of the definition of scarcity. Operating reserve targets are currently calculated based on the sum of control-zone-specific, 30-minute, day-ahead reserve requirements as defined by PJM.[71]

Operating reserve targets are designed to inform system operators of the resources, in excess of expected peak system requirements, required to maintain reliability during the peak hours. These reserves are not required during off peak hours and system operators may not always maintain the defined level of reserves during high load periods.

For purposes of defining trigger points for scarcity events, the reserve requirements and available resource measures should be defined in a way that is consistent with the nature of system operations. Operating reserve targets should be dynamic, based on current operating conditions and defined for predefined scarcity pricing regions. This is consistent with PJM's current scarcity pricing zones which are defined based on distribution factors to specific constraints.

Using a more dynamic and precise measure of operating reserves requirements, scarcity can be defined to exist when within half hour demand, including a operating reserve target, is greater than, or equal to, total, within-half hour supply excluding the impact of non market administrative intervention. Scarcity can exist at varying levels of severity, reflected by the degree to which the relevant reserve requirement exceeds within-half hour supply, excluding the impact of non market administrative actions. The more emergency resources and actions that are needed to maintain system reliability, the more severe the scarcity event.

Non market, administrative tools available to PJM to ensure that demand does not exceed supply include calling for full emergency load response, recalls of noncapacity-backed exports, loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dump.[72] Of these steps, the last four are defined in the PJM Tariff as triggers for scarcity pricing events.[73] The use of any of these measures to maintain system integrity in predefined scarcity pricing regions should provide an indication that the affected area of the system is in a state of scarcity.

Four emergency messages trigger administrative scarcity pricing under the PJM Tariff. (See Table 3-41.)[74, 75]

71 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25. See also PJM. "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

72 See PJM. "Manual 13: Emergency Operations," Revision: 27 (Effective September 5, 2006), p. 29: "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability."

73 See PJM. "Open Access Transmission Tariff (OATT)," Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.01 (Effective January 27, 2006).

74 "Maximum emergency generation loaded" covers the first three trigger events: a) Begin to dispatch online generators, which are partially designated as maximum emergency, into emergency output levels; b) Begin to dispatch online generators, which are designated entirely as maximum emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators; and c) Begin to dispatch any offline generators that are designated entirely as maximum emergency and that have start times plus notification times less than or equal to 30 minutes.

75 114 FERC ¶ 61,076 (2006).

Table 3-41 Scarcity-related emergency messages

Emergency Message	Description
Max emergency gen loaded	The purpose is to increase generation above the normal economic limit.
Voltage reduction	A request to reduce distribution level voltage by 5%, which provides load relief.
Emergency energy purchase	This is a request by PJM for emergency purchases of energy. PJM will select which offers are accepted based on price and expected duration of the need. This request is typically issued at the Max Emergency Generation emergency procedure step.
Manual load dump	The request to disconnect firm customer load (rotating blackouts). This is issued when additional load relief is needed and all other possible procedures have been exhausted. Target: Electricity Distribution Companies

Current Issues with Scarcity Implementation

There is a choice between using market signals and administrative actions to maintain the balance between supply and demand when the market is tight. Reliance on administrative actions means that there is no clear, price based signal that the system requires the use of emergency resources. In the short run, prices that reflect the shortage of resources signal the need for resources and may result in immediate responses on the supply and demand sides. In the long run, prices provide signals regarding the need for additional generation, demand-response and transmission resources in the scarcity regions.

Reliance on the use of emergency administrative steps to indicate scarcity means that the system is in a condition of scarcity prior to it being declared under the current rules. The current administrative scarcity pricing rules result in a non-locational signal within the scarcity pricing regions. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. This provides a signal that is inconsistent with economic dispatch and inconsistent with locational pricing. Further, the scarcity price signal under the current rules will not necessarily reflect the severity of the scarcity event, as the price level in a scarcity event does not reflect the severity of the shortage or the types of emergency actions taken to maintain system integrity during the scarcity event.

This suggests that the administrative definition of scarcity should include several stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff. Further, scarcity pricing should be nodal in nature. Nodal scarcity price signals would provide signals consistent with economic dispatch and locational pricing during the event

Proposed Scarcity Pricing Approach

The MMU recommends that the current scarcity rule, as provided in the PJM Tariff, be reviewed and enhanced to ensure competitive prices by introducing:

- **Locational Price Signals.** 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.

- **Stages of Scarcity Pricing.** 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.

  The level of operating reserves results in PJM implementing emergency measures. The level of the penalty factor would be a function of both the level of operating reserves and the number and nature of emergency administrative steps taken to maintain system integrity. For example, the initial penalty factor associated with the violating the operating reserve constraint could come into play whenever there were insufficient operating reserves to meet the operating reserve constraint in a given thirty minute period. Subsequent escalation of the scarcity condition would be reflected in the system and in prices by tightening the reserve requirement constraint and increasing the penalty factor associated with the reserve requirement constraint, with each emergency measure taken in a defined scarcity pricing region. So the calling of a maximum emergency generation alert that allows maximum emergency capacity to be counted toward operating reserve requirements, the calling of emergency demand response, the recall of non capacity-backed exports, the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dumps in one or more contiguous transmission zones could all cause an increase in the penalty factor. The increase in the reserve requirement constraint with emergency actions would offset the effect of the administrative step in reducing demand or expanding supply beyond economic levels.

- **Offer capping.** 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.

Operating Reserve

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, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level 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.

The level of operating reserve credits and corresponding charges decreased in 2008 by 6.5 percent compared to 2007. This was the result of a large decrease in the amount of synchronous condensing operating reserve credits, a smaller decrease in the amount of balancing operating reserve credits and an increase in the amount of day-ahead operating reserve credits.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters as well as the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues internal processes to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

The MMU has previously concluded that some modifications to PJM rules governing operating reserve credits to generators would be appropriate. Such modifications should aim to ensure that credits paid to market participants and corresponding charges paid by market participants are consistent with incentives for efficient market outcomes and to eliminate gaming incentives and the ability to exercise market power. Such modifications should address both the level of and the appropriate allocation of operating reserve charges, accounting where appropriate and possible for causal factors including location. The new operating reserve rules represent positive steps towards these goals.

On November 15, 2007, after a lengthy membership process, the PJM Members Committee (MC) approved proposed revisions to Schedule 1 of the PJM Operating Agreement and to the operating reserve business rules to enhance the efficiency of the operating reserve process by modifying the rules governing balancing operating reserves. PJM filed these changes with the Commission on September 24, 2008. PJM explained to the FERC that it delayed filing, "in order to synchronize the timing of this filing to occur after the completion of the development of the required technical and billing software changes to PJM's MSET system, which … did not occur until August 1, 2008."[76] The Commission approved PJM's filing, which became effective on December 1, 2008, but required that PJM make a compliance filing to incorporate specified business rules in the tariff.[77]

PJM submitted its compliance filing on December 24, 2008, but, in addition to the business rules that the Commission specified, also included rules related to parameter limited schedules. The compliance filing went beyond the simple steps needed for compliance and included additional revisions that differed from the rules filed by PJM and agreed to by the stakeholders. Approval of these proposed additional revisions would undermine PJM's market power mitigation as it applies

76 PJM transmittal letter in Docket No. ER08-1569-000 at 2 (September 24, 2008).
77 PJM Interconnection, L.L.C., 125 FERC ¶ 61,244 at P 40 (2008).

to operating parameter limits. On January 21, 2009, the MMU filed a protest with the FERC raising both procedural and substantive objections to PJM's approach for compliance.[78] PJM and others filed responses on February 5 and 6, 2009, and the MMU filed a response on February 17, 2009.[79] At this time, a decision from the Commission is pending.

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 Construct will be referenced as the new rules and the prior Operating Reserve Construct will be referred to as the old rules.

PJM's December 1 filing included the following salient changes to the operating reserve business rules:

- **Segmented Make-Whole Payments.** Resources will be made whole separately for the blocks of hours they operate at PJM direction. There will a maximum of two segments per calendar day, per unit. The first segment will be the greater of the day-ahead schedule or minimum run time (minimum downtime for demand resources); the second segment will be the remainder of the unit run for that calendar day.[80]

- **Parameter-Limited Schedules.** When a unit needed for operating reserve has local market power as defined by the three pivotal supplier test, units will be required to use operating parameters consistent with competitive offers. These parameters are defined by unit characteristics and included in a matrix posted by the MMU. PJM also developed business rules approved November 15, 2007, by the Members Committee that, among other things, established a process to evaluate unit-specific exceptions to the values included in the matrix.[81]

- **Generator Deviations.** PJM will use ramp-limited desired MW to determine generator deviations from desired dispatch. Pool-scheduled generators deemed to be following dispatch will not be assessed balancing operating reserve deviations.[82]

- **Netting Generator Deviations.** Generators that deviate from real-time dispatch will be able to offset deviations by using another generator at the same bus. Both generators must be owned or offered by a single PJM market participant and must have identical electrical impacts on the transmission system.[83]

- **Locational Netting of Deviation Calculations.** Demand deviations will be calculated by comparing all day-ahead demand transactions within a single transmission zone, hub, or interface against the real time demand transactions within that same transmission zone, hub,

78 Protest of the Independent Market Monitor for PJM filed in Docket No. ER08-1569-001. The Market Monitor posts a copy of this document on its Website at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM%20Protest%20re%20Operating%20Reserves%20ER08-1569.pdf>.

79 See, e.g., Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. to the Protest of the Independent Market Monitor for PJM filed in Docket No. ER08-1569-001. PJM posts this on its Website at <http://www.pjm.com/Media/documents/ferc/2009-filings/20090206-er08-1569-000.pdf>; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM filed in Docket No. ER08-1569-001 (February 6, 2009). The Market Monitor posts this on its Website at: <http://www.monitoringanalytics.com/Reports/2009/IMM%20Answer%20to%20Answers%20ER08-1569.pdf>.

80 PJM "Operating Reserve Revised Business Rules v6": Segmented Make Whole Payments at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

81 PJM "Operating Reserve Revised Business Rules v6": Minimum Generator Operating Parameters – Parameter Limited Schedule at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

82 PJM "Operating Reserve Revised Business Rules v6": Ramp-limited RT Desired MW to determine deviations at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

83 PJM "Operating Reserve Revised Business Rules v6": Supplier Netting at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

or interface. Supply deviations will be calculated by comparing all day-ahead transactions within a single transmission zone, hub, or interface against the real time transactions within that same transmission zone, hub, or interface. Generator deviations will be calculated on a unit-specific basis, except for the netting provisions. Deviations that occur within a single zone will be associated with a region and will be charged the regional balancing operating reserve rate.[84]

- **Balancing Operating Reserve Charge Allocation.** PJM will determine whether operating reserve credits are earned for reasons associated with reliability or with real-time deviations from day-ahead results. PJM will make this determination in both the reliability analysis stage and the real-time stage. Reliability related credits are allocated to be recovered from charges to real-time load plus exports and deviations related credits are allocated to be recovered from charges to deviations.[85]

- **Regional Balancing Operating Reserve Charge Allocation.** PJM will identify operating reserves credits that are associated with controlling local constraints, identified as constraints on transmission lines rated at less than or equal to 345kv. Local constraints will be identified as in the Western or the Eastern Region. The resultant operating reserve credits will be allocated as charges to all real-time deviations and real time load within a region, resulting in a Regional Adder rate for Reliability and a Regional Adder rate for Deviations.[86]

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories**.** Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-42 shows the categories of credits and charges and their relationship. The bottom half of this table also shows how credits are allocated under the new operating reserve construct. Table 3-43 shows the different types of deviations.

84 PJM "Operating Reserve Revised Business Rules v6": Netting Deviation Calculations at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

85 PJM "Operating Reserve Revised Business Rules v6": Balancing Operating Reserve Cost Allocation at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

86 PJM "Operating Reserve Revised Business Rules v6": Regional Balancing Operating Reserve Charge Allocation at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

Table 3-42 Operating reserve credits and charges

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

Table 3-43 Operating reserve deviations

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

Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market and day-ahead import transaction credits. The rules governing these credits and associated charges were not modified in the new rules.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-45 shows monthly day-ahead operating reserve charges for calendar years 2007 and 2008.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[87] The rules governing these credits and associated charges were not modified in the new rules.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-45 shows monthly synchronous condensing charges for calendar years 2007 and 2008.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, and real-time import transaction credits. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced by PJM for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to cancelled pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

Under the old rules, operating reserve charges that result from paying balancing operating reserve credits are allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market. Table 3-45 shows monthly balancing operating reserve charges for calendar years 2007 and 2008. Under the new rules, only credits identified as related to deviations are allocated to deviations. Credits identified for reliability purposes are allocated to real-time load plus exports. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly net basis. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

87 PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008).

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES);[88] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[89] plus real-time exports scheduled through the EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and b) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports scheduled through EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations continue to be calculated for individual units, except where netting at a bus is permitted.

Credit and Charge Results

Overall Results

Table 3-44 shows total operating reserve credits from 1999 through 2008, a period when significant market changes occurred.[90, 91] Total operating reserve credits decreased by 6.5 percent in 2008. Table 3-44 shows the ratio of total operating reserve credits to the total value of PJM billings.[92] This ratio decreased from 1.5 percent in 2007 to 1.3 in 2008. The ratio in 2008 is the lowest it has been since 1999. The overall results for 2008 are presented for December in a manner consistent with the calculations under the old rules to permit comparisons. The December charges are also shown in the categories defined under the new rules.

88 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

89 PJM's eSchedules is an application used by participants for internal bilateral transactions.

90 Table 3-44 includes all categories of credits as defined in Table 3-42 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on February 26th, 2008.

91 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

92 See the *2008 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2008," for a description of the value of total annual PJM billings during the period indicated.

Table 3-44 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2008

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.3412	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)

Table 3-44 shows the average operating reserve credits per MWh (or the charge rate) for each full year since the introduction of the Day-Ahead Energy Market.[93] The day-ahead operating reserve rate increased $0.0274 per MWh or 48.0 percent from $0.0570 per MWh in 2007 to $0.0844 per MWh in 2008. The balancing operating reserve rate decreased $0.2178 per MWh, or 9.3 percent, from $2.3310 per MWh in 2007 to $2.1132 per MWh in 2008.

Table 3-45 compares monthly operating reserve charges by category for calendar years 2007 and 2008. The overall decrease of 6.5 percent in 2008 is comprised of a 41.3 percent increase in day-ahead operating reserve charges, an 84.7 percent decrease in synchronous condensing charges and a 2.3 percent decrease in balancing operating reserve charges.

Total operating reserve charges in 2008 were $429,253,836, down from the total of $459,124,502 in 2007, which was primarily the result of the decrease of $31,721,586 in synchronous reserve charges. The share of day-ahead operating reserve charges to total operating reserve charges increased by 5.2 percentage points to 16.2 percent, the share of synchronous condensing charges decreased 7 percentage points to 1.3 percent, and the share of balancing charges increased 1.8 percentage points to 82.4 percent.

As of December 1, 2008, balancing charges are allocated to six separate categories. (See Table 3-47.) These categories are RTO reliability charges, East Region reliability charges, West Region reliability charges, RTO deviation charges, East Region deviation charges and West Region deviation charges. The balancing charges in Table 3-45 for December are the sum of the six categories, plus lost opportunity cost charges ($2,840,091), cancellation charges ($46,727) and all other local constraint balancing charges ($2,883).

93 In Table 3-44, "Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2008," numbers are based on data from PJM market settlements department that include manual adjustments. The data in Table 3-45, Table 3-50, Table 3-55 and Figure 3-11 are based on the PJM market settlements database and do not include manual adjustments.

Table 3-45 Monthly operating reserve charges: Calendar years 2007 and 2008

	2007			2008		
	Day-Ahead	Synchronous Condensing	Balancing	Day-Ahead	Synchronous Condensing	Balancing
Jan	$5,627,466	$2,001,215	$18,524,772	$4,126,221	$456,972	$39,935,491
Feb	$5,739,401	$2,670,396	$34,259,749	$3,731,017	$200,456	$23,165,838
Mar	$4,611,047	$1,300,459	$23,317,961	$2,904,498	$249,900	$18,916,241
Apr	$5,981,246	$1,208,114	$17,472,454	$4,213,578	$209,366	$22,559,577
May	$6,305,138	$1,584,887	$16,198,291	$10,873,205	$202,397	$22,970,363
Jun	$3,905,778	$2,706,483	$32,779,988	$7,064,877	$575,927	$65,597,311
Jul	$2,221,518	$4,374,349	$31,682,112	$7,038,834	$874,234	$48,041,415
Aug	$1,909,243	$7,495,702	$61,410,545	$6,140,554	$143,857	$26,212,547
Sep	$2,896,590	$5,046,901	$42,197,260	$4,581,147	$405,308	$27,809,898
Oct	$1,970,822	$5,024,503	$29,581,616	$6,705,261	$794,271	$16,054,255
Nov	$3,715,092	$3,332,124	$21,265,389	$5,069,462	$635,697	$21,097,016
Dec	$4,404,038	$721,130	$33,454,922	$7,175,436	$996,292	$21,525,117
Total	$49,287,379	$37,466,264	$362,145,059	$69,624,091	$5,744,678	$353,885,070
Share of Annual Charges	11.0%	8.3%	80.7%	16.2%	1.3%	82.4%

Deviations

Under the old operating reserve construct, balancing operating reserve charges were assigned to total real-time deviations from day-ahead schedules. Under the new rules, only a subset of defined balancing reserve charges are assigned to deviations and deviations are separated into RTO and regional categories. Table 3-46 shows monthly real-time deviations for demand, supply and generator categories for 2007 and 2008. Total deviations summed across the demand, supply, and generator categories were higher in 2008 than 2007. From 2007 to 2008, the share of total deviations in the demand category decreased by .8 percentage points, in the supply category increased by 4.0 percentage points and in the generator category decreased by .6 percentage points.

As of December 1, 2008, new rules governing the calculation of generator deviations were implemented. Under the old rules, a generator was considered to deviate if the unit was operating at an actual output that was more than 10 percent from the PJM desired MW, or if they were operating at an output that was 5 percent, or 5 MW from their day-ahead schedule. Under the new rules, the ramp limited desired (RLD) MW is used instead to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate.

Under the new rules, credits related to deviations and reliability are assigned to the RTO or to the Eastern or Western Region as shown in Table 3-47. For each region, credits related to reliability are allocated to real-time load plus exports, while credits related to deviations are allocated to real-time deviations. The deviations shown for December in Table 3-46 are the sum of deviations for all the regions.

Table 3-46 Monthly balancing operating reserve deviations (MWh): Calendar years 2007 and 2008

	2007 Deviations			2008 Deviations		
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)
Jan	7,514,621	2,906,334	2,340,413	8,172,164	3,297,121	2,572,113
Feb	6,233,800	2,962,485	2,243,011	6,728,062	3,046,290	2,546,510
Mar	6,358,269	2,550,649	2,376,102	6,392,821	2,520,387	2,405,061
Apr	6,234,452	2,491,365	2,309,824	5,951,654	3,127,726	2,224,157
May	5,835,288	2,701,154	2,574,414	6,624,696	3,787,650	2,699,616
Jun	7,893,872	3,928,908	2,570,994	8,117,669	3,179,999	2,644,016
Jul	7,976,794	3,369,275	2,646,549	9,237,956	3,914,230	2,213,828
Aug	8,302,998	3,262,800	3,301,138	8,296,485	4,000,974	2,275,294
Sep	6,743,208	2,400,749	2,189,309	7,360,536	3,691,646	2,577,095
Oct	6,418,244	2,631,321	2,352,370	6,792,603	3,538,950	2,404,069
Nov	6,249,638	2,407,343	2,156,888	6,561,634	3,586,432	2,267,083
Dec	7,018,333	2,896,010	2,805,085	8,399,099	4,898,506	1,775,964
Total	82,779,517	34,508,392	29,866,097	88,635,377	42,589,911	28,604,806
Share of Annual Deviations	56.3%	22.6%	18.5%	55.5%	26.6%	17.9%

Balancing Operating Reserve Charge Rate

The balancing operating reserve rate equals the balancing operating reserve credits divided by the sum of demand, supply and generator deviations. It is calculated on a daily basis. Until December 1, 2008, this was a single rate applied across the entire PJM footprint. Under the new rules, there are six separate rates. Figure 3-10 shows the monthly average balancing operating reserve rates for the past five years. In 2008, the average daily balancing operating reserve rate decreased to $2.1132 per MWh, which was lower than 2007 by $.2178 per MWh. For comparison purposes, the dashed line segment in Figure 3-10 shows the balancing charge rate for December 2008, calculated under the old rules. Table 3-47 shows the actual December averages for each regional rate.

Figure 3-10 Monthly average balancing operating reserve rate: Calendar years 2004 to 2008

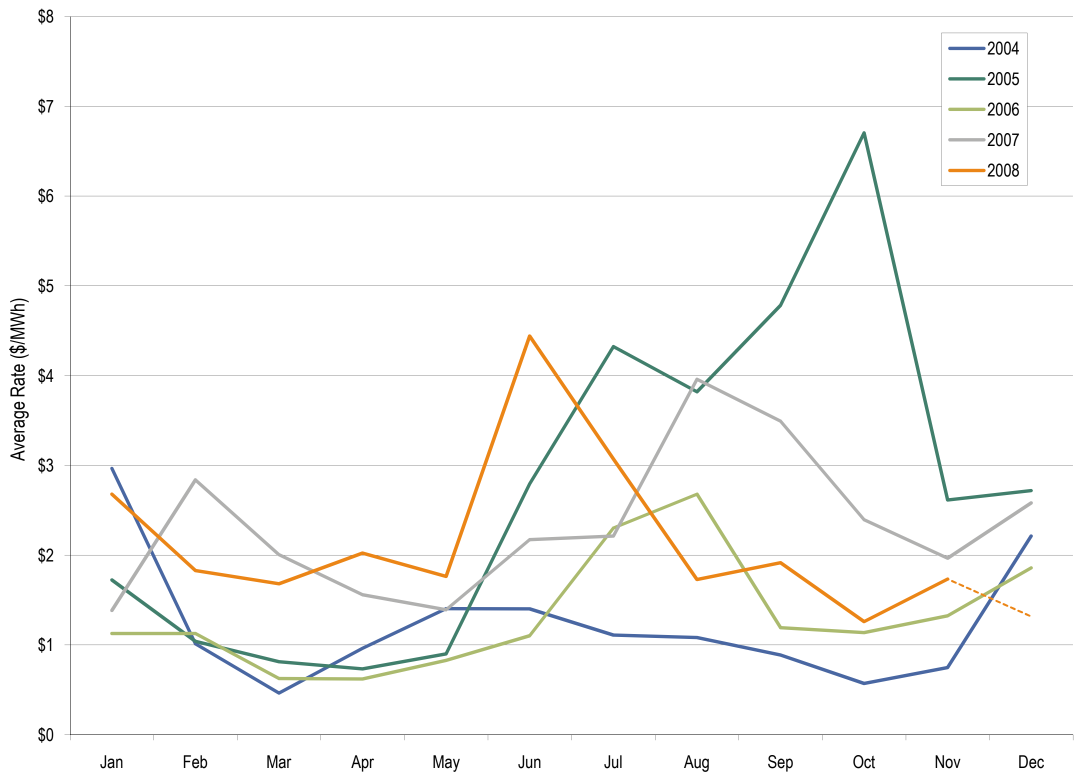


Table 3-47 Credits, deviations, rates, and charges by cost allocation category: Calendar month December 2008

	RTO Reliability	East Reliability	West Reliability	RTO Deviations	East Deviations	West Deviations
Credits ($)	$1,185,277	$24,194	$766,090	$15,989,374	$641,366	$29,114
RT Load and Exports (MWh)	63,904,484	34,102,518	29,801,966	(n/a)	(n/a)	(n/a)
Deviations (MWh)	(n/a)	(n/a)	(n/a)	15,757,287	8,922,102	6,736,430
Rates ($/MWh)	0.018	0.001	0.029	0.956	0.068	0.005
Charges ($)	$1,185,277	$24,194	$766,090	$15,989,374	$641,366	$29,114

Table 3-48 shows the total balancing reserve rate paid in each region. The East Region rate is the sum of the rates for RTO reliability charges, RTO deviation charges, East Region reliability charges and East Region deviation charges. The West Region rate is the sum of the rates for RTO reliability charges, RTO deviation charges, West Region reliability charges and West Region deviation charges. The total balancing rate for December in PJM was $1.3121 per MWh.

Table 3-48 Regional balancing operating reserve rates: December 2008

	Reliability	Deviation
East	0.019	1.025
West	0.047	0.961

Operating Reserve Credits by Category

Figure 3-11 shows that the largest share of total operating reserve credits, 63.3 percent, was paid to resources in the balancing energy market during 2008 and 82.5 percent of total operating reserve credits were in the balancing category, which includes the balancing energy market, real-time transactions, and lost opportunity costs. Figure 3-11 also shows that 16.2 percent of total operating reserve credits was paid to resources in the Day-Ahead Energy Market and that 16.2 percent of total operating reserve credits were in the day-ahead category, which includes the day-ahead energy market and day-ahead transactions. The remaining 1.3 percent of total credits was paid to resources in the synchronous condensing category.

Figure 3-11 Operating reserve credits: Calendar year 2008

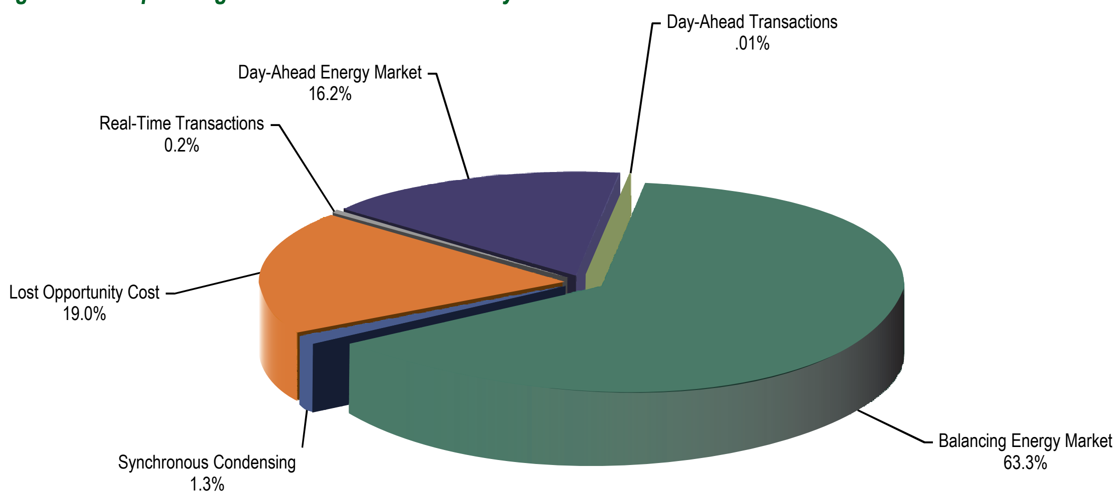


Table 3-49 shows the monthly totals for each type of credit for 2008. The highest monthly operating reserve credits were paid in June, $73,238,115, or 17.1 percent, of the total annual operating reserves. The second highest monthly operating reserve credits were paid in July, $55,954,483, or 13.0 percent, of the total annual operating reserves. June and July had the highest monthly loads in 2008. The four summer months of May, June, July, and August represented 45.6 percent of the total yearly credit share.

Table 3-49 Credits by month (By operating reserve market): Calendar year 2008

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Real-Time Transactions	Lost Opportunity Cost	Total
Jan	$4,123,747	$2,474	$456,972	$34,597,759	$0	$5,337,732	$44,518,684
Feb	$3,731,017	$0	$200,457	$20,076,502	$0	$3,089,337	$27,097,312
Mar	$2,904,498	$0	$249,899	$15,657,684	$0	$3,258,557	$22,070,639
Apr	$4,208,697	$4,881	$209,366	$16,091,629	$0	$6,467,948	$26,982,522
May	$10,873,205	$0	$202,397	$17,518,558	$779,649	$4,672,156	$34,045,964
Jun	$7,033,102	$31,774	$575,927	$51,043,907	$0	$14,553,404	$73,238,115
Jul	$7,035,717	$3,117	$874,234	$35,016,411	$47,984	$12,977,019	$55,954,483
Aug	$6,133,170	$7,385	$143,857	$14,788,450	$0	$11,424,097	$32,496,959
Sep	$4,581,146	$0	$405,308	$20,040,461	$0	$7,769,436	$32,796,353
Oct	$6,705,260	$0	$794,271	$11,847,567	$0	$4,206,688	$23,553,787
Nov	$5,069,462	$0	$635,697	$16,259,651	$0	$4,837,365	$26,802,174
Dec	$7,175,436	$0	$996,292	$18,685,027	$0	$2,840,091	$29,696,846
Total	$69,574,458	$49,631	$5,744,678	$271,623,607	$827,633	$81,433,829	$429,253,836

Characteristics of Credits and Charges

Types of Units

Table 3-50 shows the percentage of credits received by each unit type for each type of operating reserves. (Each row sums to 100 percent.) Of the $93,476,181 in credits received by combined-cycle units, 33.1 percent were received in the day-ahead market, 63.9 percent in the balancing energy market and 3.0 percent through lost opportunity cost credits. Combustion turbines received the most operating reserve credits with $215,651,185, 76.7 percent from the balancing generator credits.

Table 3-50 Credits by unit types (By operating reserve market): Calendar year 2008

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	33.1%	0.0%	63.9%	3.0%	$93,476,181
Combustion Turbine	1.5%	2.7%	76.7%	19.1%	$215,651,185
Diesel	0.1%	0.0%	23.9%	75.9%	$4,528,081
Hydro	0.0%	0.0%	100.0%	0.0%	$440,922
Nuclear	0.0%	0.0%	0.0%	100.0%	$4,552,301
Steam	32.2%	0.0%	40.9%	26.9%	$109,712,721
Wind Farm	0.0%	0.0%	100.0%	0.0%	$15,182

Table 3-51 shows the percentage of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and conventional steam units were paid 95.2 percent of the day-ahead generator credits. Combustion turbines received 100 percent of the synchronous condensing credits. Combined-cycles and combustion turbines were paid 82.9 percent of the balancing generator credits.

Table 3-51 Credits by operating reserve market (By unit type): Calendar year 2008

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	44.5%	0.0%	22.0%	3.4%
Combustion Turbine	4.8%	100.0%	60.9%	50.5%
Diesel	0.0%	0.0%	0.4%	4.2%
Hydro	0.0%	0.0%	0.2%	0.0%
Nuclear	0.0%	0.0%	0.0%	5.6%
Steam	50.7%	0.0%	16.5%	36.3%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$69,574,458	$5,744,678	$271,623,607	$81,433,829

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to LMP. Noneconomic generation includes units that are producing energy but at a higher offer price than the LMP. Noneconomic generation includes units assigned by PJM to run and units not assigned by PJM to run or to provide regulation. Regulation generation includes units assigned by PJM to provide regulation. The level of noneconomic generation is an indicator of the level of generation that may require operating reserve credits. However, the data are hourly and some generation that is noneconomic for an hour may receive adequate market revenues during other hours to offset any shortfall.[94]

Table 3-52 shows the percentage of total PJM self-scheduled generation, economic generation, noneconomic generation and regulation generation for 2008. The percentage of self-scheduled generation in all hours decreased 3.0 percentage points since 2007, economic generation increased 0.9 percentage points, noneconomic generation increased 1.6 points and regulation increased 0.6 percentage points.

Table 3-52 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2008

	All Hours	On Peak	Off Peak
Self-scheduled generation	43.1%	41.7%	46.4%
Economic generation	48.5%	52.9%	37.9%
Noneconomic generation	6.6%	4.6%	11.3%
Regulation generation	1.9%	0.8%	4.4%
Total	100%	100%	100%

94 Self-scheduled units were not included in either economic or noneconomic categories. Self-scheduled units are those units which indicate to PJM that they are self scheduled. Units which are operating, but are not assigned by PJM to run and are not self scheduled, are noneconomic.

Table 3-53 presents the share of self-scheduled, economic, noneconomic and regulation generation by unit type. (Each column adds to 100 percent.) In 2008, steam units represented 93.8 percent of all self-scheduled generation, 92.9 percent of all economic generation and 71.9 percent of noneconomic generation. Noneconomic combustion turbine generation decreased from 8.9 percent in 2007 to 4.7 percent in 2008, while noneconomic steam increased 5.0 percentage points.

Table 3-53 PJM generation by unit type receiving operating reserve payments: Calendar year 2008

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.1%	5.8%	23.3%	9.2%
Combustion turbine	0.2%	0.4%	4.7%	0.3%
Diesel	0.2%	0.0%	0.1%	0.0%
Hydroelectric	2.5%	0.9%	0.0%	0.0%
Steam	93.8%	92.9%	71.9%	90.5%
Wind	0.2%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

Table 3-54 presents the share of each unit type by self-scheduled, economic, noneconomic and regulation generation. (Each row adds to 100 percent.) For example, in 2008, 43.8 percent of steam unit generation was self-scheduled, 49.2 percent was economic, 5.2 percent was noneconomic and the remaining 1.8 percent was regulation generation. In 2008, 99.2 percent of wind generation and 72.1 percent of hydroelectric generation was self-scheduled. In 2008, 50 percent of combustion turbine generation was noneconomic, which is consistent with Table 3-51 which shows that a large percentage of balancing generator credits was paid to CTs. Combined-cycle noneconomic generation increased by 5.3 percentage points from 2007 and noneconomic combustion turbine generation increased 7.4 percentage points.

Table 3-54 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2008

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	22.8%	47.9%	26.4%	2.9%	100%
Combustion turbine	14.9%	34.0%	50.0%	1.1%	100%
Diesel	89.7%	6.0%	4.3%	0.0%	100%
Hydroelectric	72.1%	27.9%	0.0%	0.0%	100%
Steam	43.8%	49.2%	5.2%	1.8%	100%
Wind	99.2%	0.8%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-55 compares the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Mid-Atlantic Region, to the share of charges paid by generators and credits paid by and to generators located within all other PJM control zones. The other control zones include those in the Western Region (the AEP, AP, ComEd, DAY and DLCO control zones) and in the Southern Region (the Dominion Control Zone). The new rules separate balancing operating reserves into Eastern and Western Regions, which are different than this definition. On average, 40.6 percent of balancing generator charges and 39.2 percent of LOC charges were paid by generators in the Mid-Atlantic Region while these generators received 64.9 percent of balancing generator credits and 25.8 percent of LOC credits. Table 3-55 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 14.1 percent of all operating reserve charges and generator credits were 80.8 percent of all operating reserve credits.

Table 3-55 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2008

	Mid-Atlantic Region				Other Control Zones					
	Generation Charge	LOC Charge	Generation Credit	LOC Credit	Generation Charge	LOC Charge	Generation Credit	LOC Credit	Generation and LOC Charges Share of Total Operating Reserves Charges	Generation and LOC Credits Share of Total Operating Reserves Credits
Jan	$2,779,405	$416,933	$25,933,909	$1,077,820	$3,465,890	$520,471	$8,663,850	$4,259,912	16.1%	89.7%
Feb	$1,882,858	$272,094	$13,013,407	$553,665	$2,429,882	$357,550	$7,063,095	$2,535,672	18.2%	85.5%
Mar	$1,501,880	$314,764	$11,313,168	$472,558	$1,607,090	$351,973	$4,344,515	$2,785,999	17.1%	85.7%
Apr	$1,025,306	$402,742	$10,070,917	$1,244,823	$1,948,928	$819,405	$6,020,712	$5,223,125	15.6%	83.6%
May	$1,338,311	$353,622	$13,970,992	$2,808,376	$2,242,991	$539,611	$3,547,565	$1,863,780	13.1%	65.2%
Jun	$4,036,002	$1,134,314	$32,013,721	$3,632,667	$5,455,511	$1,534,193	$19,030,186	$10,920,738	16.6%	89.6%
Jul	$2,005,513	$703,884	$19,494,752	$1,787,134	$2,870,811	$1,072,708	$15,521,659	$11,189,885	11.9%	85.8%
Aug	$943,341	$677,883	$7,159,590	$741,681	$1,382,157	$1,004,967	$7,628,860	$10,682,415	12.3%	80.7%
Sep	$1,167,003	$425,155	$11,422,817	$2,211,475	$2,631,141	$998,163	$8,617,645	$5,557,962	15.9%	84.8%
Oct	$791,852	$293,766	$7,500,479	$2,665,500	$1,452,304	$519,462	$4,347,088	$1,541,188	13.0%	68.2%
Nov	$1,097,894	$319,020	$11,503,444	$2,878,009	$1,782,839	$537,532	$4,756,207	$1,959,355	13.9%	78.7%
Dec	$596,709	$85,160	$12,910,690	$966,217	$767,946	$121,728	$5,774,337	$1,873,874	5.3%	72.5%
Average	40.6%	39.2%	64.9%	25.8%	59.4%	60.8%	35.1%	74.2%	14.1%	80.8%

Market Power Issues

The exercise of market power by units that are paid operating reserve credits also contributes to the level of operating reserve charges paid by PJM members. Market power issues are first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The top 10 units are relevant, not because these are the only units with the ability to exercise market power, but because operating reserve credits have been so highly concentrated in payments to these units over the last several years. The focus on the top 10 units is illustrative. The market power analysis includes a calculation of the impact on total operating reserve credits of payments to generators associated with markups of price over cost in excess of the competitive level. Unit operating parameters also play a role in the level of operating reserve credits paid to units. The submission of inflexible operating parameters, including artificially long minimum run times, arbitrarily small numbers of starts, daily and hourly economic minimum and economic maximum points that are arbitrarily close or equal, contribute to higher levels of operating reserve credits.

A complete resolution of the market power issue in the payment of operating reserve credits must provide to PJM operators better tools for defining and making optimal economic choices and must define the relevant market, must determine when the market is structurally noncompetitive and must apply mitigation in such situations. The new operating reserve rules represent positive steps towards these goals.

Top 10 Units

A disproportionately large share of operating reserve credits has been paid to a small number of units and companies since 2001. This continued to be the case in 2008. As Table 3-56 shows, the top 10 units receiving total operating reserve credits, which makes up less than 1 percent of all units in PJM's footprint, received 18.78 percent of total operating reserve credits in 2008, a decrease from the 29.75 percent in 2007. The top 20 units received 25.74 percent of total operating reserve credits in 2008 and 39.8 percent in 2007. In 2008, six companies owned the units that received the 10 most total operating reserve credits. In 2007, the top generation owner received 8 percent of the total operating reserve credits paid, and in 2008, the top generation owner received 24.9 percent of the total operating reserve credits.

Table 3-56 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2008

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.67%	1.81%
2002	32.01%	1.54%
2003	39.28%	1.28%
2004	46.28%	0.90%
2005	27.67%	0.79%
2006	29.72%	0.83%
2007	29.75%	0.84%
2008	18.78%	0.81%

Table 3-57 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $30,261,347 for 2008, or 7.1 of the total operating reserve credits paid to all units. The cumulative distribution column shows that the top 10 units had an 18.8 percent share of the total operating reserve credits in 2008. The top organization had a 24.9 percent share of the total credits, or $106,695,434. The top 10 organizations receiving credits had a cumulative share of 77.0 percent.

Table 3-57 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2008

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$30,261,347	7.1%	7.1%	$106,695,434	24.9%	24.9%
2	$12,901,176	3.0%	10.1%	$43,552,146	10.2%	35.1%
3	$6,151,524	1.4%	11.5%	$36,049,644	8.4%	43.5%
4	$5,205,118	1.2%	12.7%	$34,340,514	8.0%	51.5%
5	$4,860,844	1.1%	13.9%	$23,358,959	5.5%	56.9%
6	$4,658,680	1.1%	14.9%	$21,919,710	5.1%	62.1%
7	$4,291,570	1.0%	16.0%	$17,022,398	4.0%	66.0%
8	$4,270,922	1.0%	16.9%	$16,040,512	3.7%	69.8%
9	$4,149,643	1.0%	17.9%	$15,767,381	3.7%	73.5%
10	$3,706,280	0.9%	18.8%	$15,309,222	3.6%	77.0%

Table 3-58 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $12,704,113, or 18.3 percent of the total day-ahead generator credits. The second unit had a 14.3 percent share, which when combined with the top unit was 32.6 percent of the total credits. The top organization received 41.8 percent of the day-ahead credits. The top 10 organizations received 82.7 percent of the day-ahead credits.

Table 3-58 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2008

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$12,704,113	18.3%	18.3%	$29,100,202	41.8%	41.8%
2	$9,980,785	14.3%	32.6%	$6,450,891	9.3%	51.1%
3	$2,275,960	3.3%	35.9%	$4,556,031	6.5%	57.6%
4	$1,571,500	2.3%	38.1%	$3,429,155	4.9%	62.6%
5	$1,355,966	1.9%	40.1%	$3,345,546	4.8%	67.4%
6	$1,194,598	1.7%	41.8%	$2,931,890	4.2%	71.6%
7	$942,432	1.4%	43.2%	$2,591,653	3.7%	75.3%
8	$921,523	1.3%	44.5%	$1,821,745	2.6%	77.9%
9	$911,270	1.3%	45.8%	$1,705,059	2.5%	80.4%
10	$907,833	1.3%	47.1%	$1,611,128	2.3%	82.7%

Table 3-59 rank orders the top 10 units receiving synchronous condensing credits, and the top 10 organizations receiving synchronous condensing credits. The top organization received 96.7 percent of synchronous condensing credits.

Table 3-59 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2008

	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	$537,309	9.4%	9.4%	$5,552,603	96.7%	96.7%
2	$520,789	9.1%	18.4%	$98,855	1.7%	98.4%
3	$494,227	8.6%	27.0%	$90,273	1.6%	99.9%
4	$474,565	8.3%	35.3%	$2,947	0.1%	100.0%
5	$434,112	7.6%	42.8%			
6	$398,650	6.9%	49.8%			
7	$394,881	6.9%	56.7%			
8	$392,302	6.8%	63.5%			
9	$188,842	3.3%	66.8%			
10	$184,737	3.2%	70.0%			

Table 3-60 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 24.5 percent of total credits. The top ten organizations received a total of 79.2 percent of all the balancing generator credits.

Table 3-60 Top 10 units and organizations receiving balancing generator credits: Calendar year 2008

	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	$17,537,872	6.5%	6.5%	$66,630,281	24.5%	24.5%
2	$5,296,063	1.9%	8.4%	$31,251,549	11.5%	36.0%
3	$4,815,831	1.8%	10.2%	$30,354,894	11.2%	47.2%
4	$4,510,532	1.7%	11.8%	$16,655,422	6.1%	53.3%
5	$4,393,615	1.6%	13.5%	$16,293,608	6.0%	59.3%
6	$3,518,939	1.3%	14.8%	$15,141,998	5.6%	64.9%
7	$3,319,601	1.2%	16.0%	$13,954,992	5.1%	70.0%
8	$3,036,191	1.1%	17.1%	$11,145,693	4.1%	74.1%
9	$2,904,919	1.1%	18.2%	$7,084,880	2.6%	76.7%
10	$2,674,513	1.0%	19.1%	$6,781,275	2.5%	79.2%

Table 3-61 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 29.4 percent of the total lost opportunity cost credits and 89.2 percent were received by the top 10 organizations.

Table 3-61 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2008

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$3,427,138	4.2%	4.2%	$23,912,992	29.4%	29.4%
2	$3,411,938	4.2%	8.4%	$17,013,392	20.9%	50.3%
3	$3,121,215	3.8%	12.2%	$8,645,943	10.6%	60.9%
4	$2,248,038	2.8%	15.0%	$5,412,348	6.6%	67.5%
5	$2,113,906	2.6%	17.6%	$4,304,560	5.3%	72.8%
6	$2,056,261	2.5%	20.1%	$3,891,327	4.8%	77.6%
7	$2,039,438	2.5%	22.6%	$2,953,077	3.6%	81.2%
8	$2,013,224	2.5%	25.1%	$2,672,636	3.3%	84.5%
9	$1,974,982	2.4%	27.5%	$2,248,038	2.8%	87.3%
10	$1,964,603	2.4%	29.9%	$1,576,844	1.9%	89.2%

Figure 3-12 plots the four operating reserve generator categories to show the distribution of the units receiving credits. The vertical axis shows the cumulative percentage of credits that were received, while the horizontal axis shows the cumulative percentage of the units that received those credits. In this figure, 100 percent of units do not represent 100 percent of all PJM units, but 100 percent of all the units that received credits in each category. For example, 90 percent of the lost opportunity cost credits were received by approximately 22 percent of the units that received lost opportunity cost credits.

Figure 3-12 Cumulative distribution of units receiving credits (By operating reserve category): Calendar year 2008

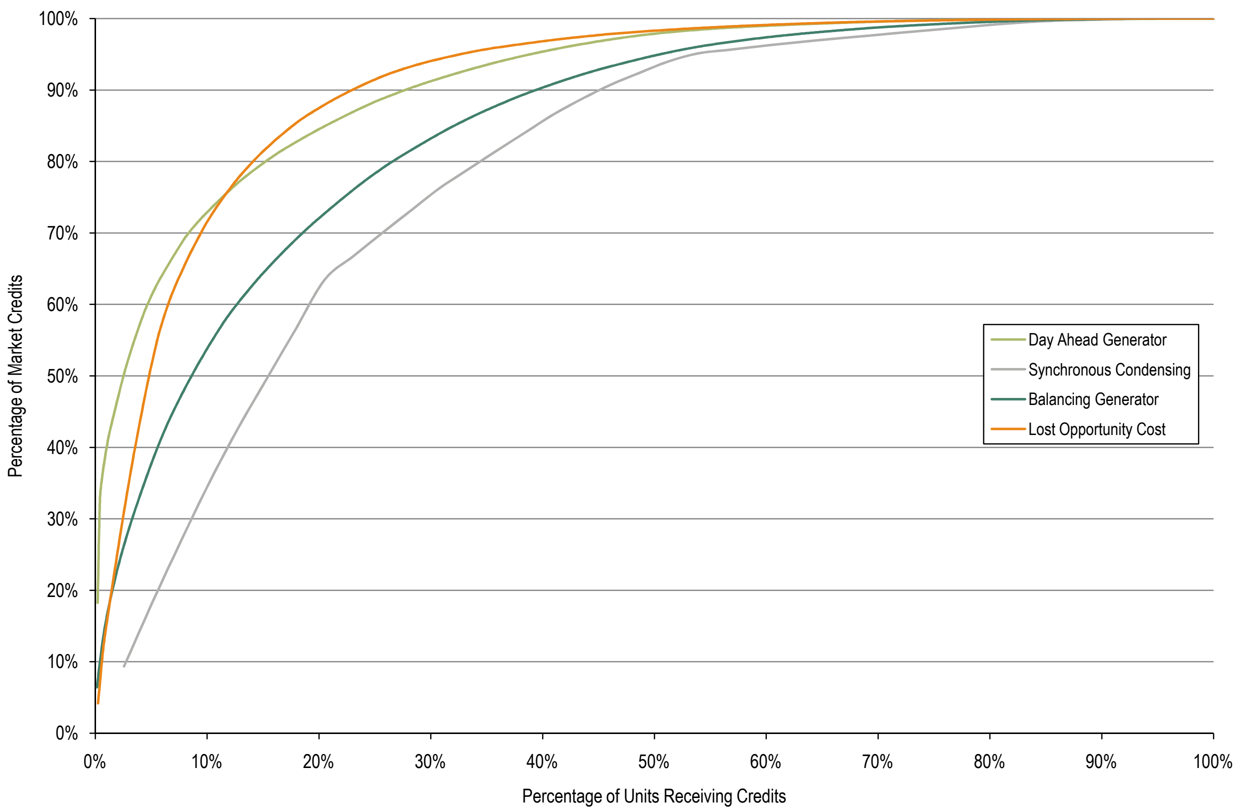
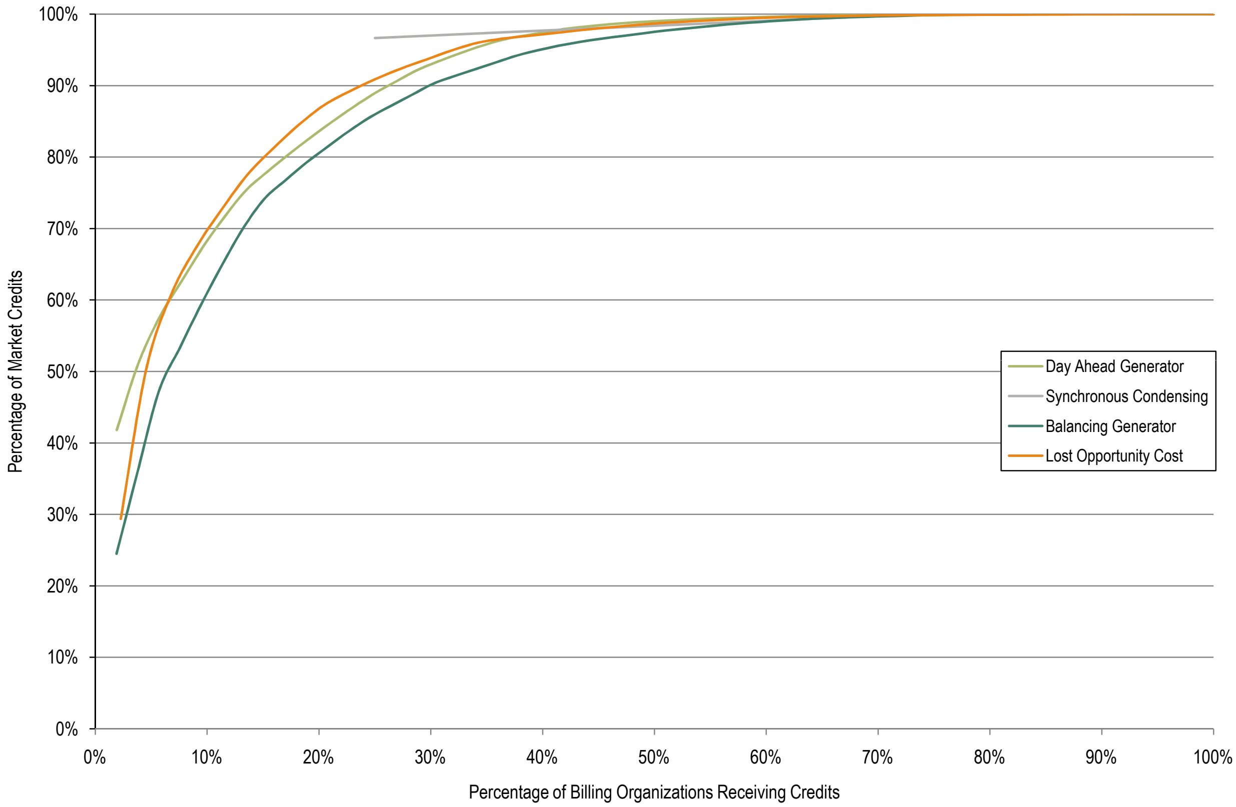


Figure 3-13 shows the distribution of credits among organizations. For example, 96.7 percent of synchronous condensing credits were paid to 25 percent of the organizations that received synchronous condensing credits.

Figure 3-13 Cumulative distribution of billing organizations receiving credits (By operating reserve market): Calendar year 2008



Markup

Unit Markup - Top 10 Units

The MMU analyzed the top 10 units receiving operating reserves credits to determine the contribution that markup makes to operating reserve payments.[95] Table 3-62 shows that the markup for the top 10 units averaged 6.5 percent in 2008, the lowest it has been since 2004 when the average markup for the top 10 units was 3.0 percent. The markup for the top 10 units is a weighted average, weighted by generator output when operating reserve credits are paid.

The generation owner with the largest share of total operating reserve credits received 53.7 percent of Energy Market operating reserve credits paid to the top 10 units and had a weighted average markup of 0.0 percent in 2008. The second generation owner received 16.4 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 25.1

95 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 9 (January 23, 2009). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

percent and the third generation owner received 11.8 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 5.4 percent in 2008.

For each year 2001 to 2006, and 2008, the top 10 units receiving operating reserve credits were either combined-cycle (CC) technology or conventional steam generation. In 2007, one unit out of the top 10 units receiving operating reserve credits was CT technology, while the rest remained CC technology or conventional steam generation. Steam units represented 22.3 percent of the credits received by the top 10 in 2008 and CC units accounted for 77.7 percent. The weighted average markup for those steam units was -1.4 percent, while combined-cycles had a weighted average markup of 9.0 percent, as seen in Table 3-62.

Table 3-62 Top 10 operating reserve revenue units markup: Calendar years 2001 to 2008

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	Combined Cycle Percent of Top 10	Combined Cycle Markup	Combustion Turbine Percent of Top 10	Combustion Turbine Markup
2001	2.9%	60.2%	2.2%	39.8%	7.4%	0.0%	0.0%
2002	11.3%	54.4%	8.0%	45.6%	20.4%	0.0%	0.0%
2003	16.9%	50.1%	19.4%	49.9%	11.3%	0.0%	0.0%
2004	3.0%	12.2%	0.1%	87.8%	4.9%	0.0%	0.0%
2005	75.4%	20.3%	52.9%	79.7%	81.7%	0.0%	0.0%
2006	20.9%	9.6%	1.8%	90.4%	24.5%	0.0%	0.0%
2007	45.8%	18.2%	28.8%	77.6%	47.1%	4.2%	56.6%
2008	6.5%	22.3%	(1.4%)	77.7%	9.0%	0.0%	NA

Unit Markup - All Units

PJM's offer-capping rules had provided that specific units were exempt from offer capping, based on their date of construction. On May 17, 2008, exempt units became subject to offer capping.[96] Three of the top 10 units receiving total operating reserve credits in 2008 were among these previously exempt units and all were combined-cycles. Table 3-63 shows the average markup for previously exempt and non-exempt units for each unit class for days when those units received operating reserve credits in each category. The table covers the period from January 1, 2008 to May 17, 2008, the day exemptions were ended. Exempt combined-cycle and combustion turbine units that received operating reserves credits in the balancing market had a higher weighted markup than such units receiving day-ahead operating reserve credits.[97]

96 See the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Exempt Unit Markup."

97 No exempt steam units received day-ahead operating reserves in 2008. The -59.1 percent markup of an exempt unit in the balancing market was the result of a single unit that received credits of $11,101.

Table 3-63 Weighted average generator markup (By exemption status): January 1, 2008, through May 16, 2008

	Day-Ahead Market		Balancing Market	
Unit Class	Exempt	Non-Exempt	Exempt	Non-Exempt
All Units	3.6%	12.8%	29.4%	(7.7%)
Combined Cycle	3.2%	8.2%	31.8%	(16.9%)
Combustion Turbine	44.4%	56.1%	51.4%	8.5%
Diesel	14.4%	4.7%	13.3%	(40.5%)
Steam	NA	16.7%	(59.1%)	(7.4%)

Table 3-64 shows the total credits received by both previously exempt and non-exempt units in each market. Non-exempt combustion turbines in the balancing market received the most credits and had a weighted markup of 8.5 percent.

Table 3-64 Day-ahead and balancing market credits (By exemption status): January 1, 2008, through May 16, 2008

	Day-Ahead Market		Balancing Market	
Unit Class	Exempt	Non-Exempt	Exempt	Non-Exempt
All Units	$1,613,871	$16,160,764	$19,058,145	$95,176,249
Combined Cycle	$1,467,279	$10,221,571	$14,059,550	$14,132,198
Combustion Turbine	$144,778	$268,365	$4,653,060	$59,323,130
Diesel	$1,814	$875	$334,435	$1,044,442
Steam	$0	$5,669,954	$11,101	$20,676,479

If exempt combined-cycle units in the balancing market had a zero percent markup rather than 31.8 percent, and all other things were held constant, total balancing credits for exempt combined-cycle units would have lower by $3,392,482.[98] (See Table 3-65.)

Table 3-65 Impact of markup on operating reserve credits (By exemption status and market): January 1, 2008, through May 16, 2008

	Day-Ahead Market		Balancing Market	
Unit Class	Exempt	Non-Exempt	Exempt	Non-Exempt
All Units	$56,150	$1,832,633	$4,324,776	
Combined Cycle	$46,152	$772,201	$3,392,482	
Combustion Turbine	$44,544	$96,414	$1,579,438	$4,660,514
Diesel	$228	$39	$39,314	
Steam		$813,265		

98 There are blank cells in Table 3-65 corresponding to negative mark ups. Total balancing credits were recalculated only for positive markups.

Unit Operating Parameters

Operating reserve credits also result from the submission of artificially restrictive, unit-specific operating parameters. For example, if a unit is needed by PJM for reliability purposes and if that unit, with a price offer equal to its cost offer, has only one permitted start per day although it is capable of three, has a 24-hour minimum run time although its actual minimum run time is four hours and a two-hour start time although its actual start time is 30 minutes, then it receives higher operating reserve payments than if those operating parameters were not in place. Once a unit is turned on for PJM for reliability reasons, operating reserve rules require that PJM pay the unit the difference between market revenues and its offer, including its offered operating parameters. Thus, PJM members have to pay this unit its offer price for 24 hours although if the unit had offered its actual capability to PJM, payments would have been made for only four hours. If a unit sets its economic minimum output level at, or close to, its economic maximum output level, although the actual minimum and maximum output levels have a significant differential, PJM members have to pay the unit its offer price for its inflated offered economic minimum. If the unit had offered its actual economic minimum to PJM, PJM could have reduced the unit's output to that minimum when LMP fell below its offer price, thus reducing operating reserve credits and charges. Restrictive operating parameters can also interact with unit-specific markups to increase operating reserve payments to units.

The new operating reserves rules address the parameter issue by establishing a parameter limited schedule that will help prevent the use of arbitrarily inflexible operating parameters when units have local market power.[99]

99 See PJM "Parameter Limited Schedule Matrix," for parameter levels at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/20080916-parameter-limited-schedule-matrix.ashx>.