SECTION 3 – ENERGY MARKET, PART 2

The PJM Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2007.[1] As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the nature of new investment in capacity in PJM, the definition and existence of scarcity conditions in PJM and the issues associated with operating reserve credits and charges.

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, 2007 net revenue showed a significant increase over 2006. This was the result of higher prices in both the Energy and Capacity Markets. The levels of net revenue in 2007 for new peaking, midmerit and coal-fired baseload vary significantly by location. The fixed costs of constructing a new entrant combustion turbine, combined-cycle or coal-fired steam generation resource were fully covered in some, but not all, PJM control zones. There was revenue adequacy in 2007 for the combined-cycle (CC) technology for more zones than for either the combustion turbine (CT) or pulverized-coal (CP) technologies. Revenues associated with the sale of capacity resources increased significantly in 2007 as the result of the introduction of the Reliability Pricing Model (RPM) construct. The results from 2007 mark a reversal of the trend from the prior eight-year period, 1999 to 2006. The increased net revenues in 2007 were the result of higher locational energy prices and of much higher locational capacity prices.[2]

  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 2007 net revenue using PJM real-time average locational marginal prices (LMPs) was $48,530 per MW-year for a CT, the zonal maximum net revenue was $96,913 in the Pepco Control Zone and the minimum was $16,047 in the DAY Control Zone.[3] While the PJM average net revenue in

1 As part of this analysis, the Market Monitoring Unit (MMU) compared the market results in 2007 to those of 2006 and certain other prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 For the eight-year period 1999 to 2006, capacity revenues were lower than during 2007 and generally decreasing with the exception of 2001 when market power issues affected prices.

3 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.

2007 was $100,809 per MW-year for a CC, the zonal maximum net revenue was $175,698 in the Pepco Control Zone and the minimum was $41,958 in the AEP Control Zone. While the PJM average net revenue in 2007 was $277,284 per MW-year for a CP, the zonal maximum net revenue was $384,940 in the Pepco Control Zone and the minimum was $157,544 in the DLCO Control Zone.

Existing and Planned Generation

- PJM Installed Capacity. During the period January 1, through December 31, 2007, PJM installed capacity remained relatively flat. Retirements were offset by new additions and the installed capacity on December 31, 2007, was only 658 MW more than on January 1, 2007.

- PJM Installed Capacity by Fuel Type. At the end of 2007, PJM installed capacity was 163,498 MW. Of the total installed capacity, 40.5 percent was coal; 29.1 percent was natural gas; 18.9 percent was nuclear; 6.5 percent was oil; 4.5 percent was hydroelectric; and 0.4 percent was solid waste.

- Generation Fuel Mix. During 2007, coal provided 55.3 percent, nuclear 33.9 percent, natural gas 7.7 percent, oil 0.5 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.2 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. There were 157 hours of high load that occurred in 2007, of which 21 occurred in June, 40 occurred in July and 96 occurred in August. This number of high-load hours is more than twice the 70 high-load hours in 2006. Within these 157 hours, there were three hours, the hours beginning 1500 through 1700, on August 8 that met the criteria for potential within-hour scarcity.[4] PJM triggered its scarcity pricing events between 1505 and 1812. This represents a clear improvement over 2006 when 10 hours met the criteria for potential within-hour scarcity while no scarcity events were triggered.

- Scarcity Pricing Events in 2007. In 2005 it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for administratively employed emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administratively based, scarcity pricing mechanism. PJM implemented administratively based, scarcity pricing rules in 2006.[5] Based on the definition of scarcity in the Tariff, there were two official scarcity pricing events on August 8, 2007: one in the Bedington — Black Oak Scarcity Pricing Zone between 1505 and 1812 and the other in the Mid-Atlantic Scarcity Pricing Region between 1555 and 1733.

4 Scarcity is considered to exist when hourly demand, including a total operating reserve requirement, is greater than, or equal to, total, within-hour supply in the absence of non market administrative intervention.

5 114 FERC ¶ 61,076 (2006).

- Modifications to Scarcity Pricing. 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. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant. The MMU reviewed the summer of 2007 for scarcity conditions and the market prices that resulted. Based on the results, the MMU suggests that PJM's scarcity pricing mechanism be reviewed and modified. The definition of scarcity should include several stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff. PJM should also consider adding new scarcity pricing regions. There would have been six hours of scarcity under PJM rules if BGE and Pepco had been defined to be a scarcity region. In addition, the actual market signal needs further refinement. The single scarcity price signal should be replaced by locational signals. Locational signals could be implemented via scarcity offers submitted by generation owners. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. Combined with a more refined set of scarcity triggers, this approach would also encourage participants to offer competitively under normal market conditions and competitively in the context of scarcity conditions.

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 2007. The level of operating reserve credits and corresponding charges increased in 2007 by 42.45 percent compared to 2006. The amount of balancing operating reserve credits paid to synchronous condensing increased by 176.79 percent compared to 2006, 17.49 percent of the total net increase.

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 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 has generally been 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 are some units in PJM, needed for reliability, that have had revenues that are not adequate to cover annual going-forward costs and that their owners, therefore, wish 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. 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.

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, 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.[6] 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.[7]

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.

6 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 the day of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

7 The peak-hour, economic dispatch model is a realistic simulation of market outcomes that, in contrast to the perfect dispatch model, considers applicable constraints faced by PJM dispatchers. There are instances in the model when a unit is dispatched for a block that yields negative net energy revenue and, consistent with actual PJM operating practices, is made whole by operating reserve payments.

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 2007 for the Real-Time Energy Market and during 2000 to 2007 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.[8] For example, during 2007, if a unit had marginal costs (i.e., 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 2007, adjusted for forced outages, it would have received $235,215 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 $207,702 per installed MW-year in net revenue from the Day-Ahead Energy Market.[9]

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 2007.

8 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; i.e., the $100 range 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.

9 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 that same hour of operation.

Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2007

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

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 2007.[10]

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2007

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

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 2007 than in 2006 for every level of unit marginal costs up to and including $140 per MWh. For units with marginal costs equal to, or less than, $70, net revenues were higher in 2007 than in any other year, except 2005, since PJM introduced markets in 1999. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve was higher in 2007 than in 2006 for every marginal cost level up to and including $90. For units with marginal costs equal to, or less than, $80, net revenues were higher in 2007 than in any other year except 2005, since PJM introduced the Day-Ahead Energy Market in 2000.

The increase in 2007 Real-Time Energy Market net revenue compared to 2006 is the result of changes in the frequency distribution of energy prices. In 2007, prices were greater than, or equal to, $30 per MWh

10 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.

more frequently than in 2006 yet less frequently compared to 2005. The 2007 simple average LMP was $57.58 per MWh, a substantial increase compared to $49.27 per MWh in 2006 and just below the 2005 simple average of $58.08 per MWh. This explains why 2007 Energy Market net revenue falls between 2005 and 2006 for most marginal cost levels. In 1999, the Real-Time Energy 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 and 79 percent in 2007.

The increase in 2007 as compared to 2006 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2007, prices were greater than, or equal to, $30 more frequently than in 2006 as the 2007 simple average LMP was $54.67 per MWh in 2007 compared to $48.10 per MWh in 2006 and $57.89 per MWh in 2005. 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 and in 2007, 84 percent.

The distribution of prices reflects a number of factors including load levels and fuel costs. An efficient CT could have produced energy at an average cost of $30 in 1999, but $90 in 2007. An efficient CC could have produced energy at an average cost of $20 in 1999, but $55 in 2007. An efficient CP could have produced energy at an average cost of $20 in 1999, but $25 in 2007. Average price levels in 2007 were slightly lower than in 2005 and, as a result, net revenue levels were lower for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. Nonetheless, Energy Market net revenues for a new entrant CT, CC and CP were significantly higher in 2007 than in 2005 because the average delivered price of natural gas was about 19 percent lower in 2007 than in 2005. From 2005 to 2006, natural gas prices dropped, as did PJM price levels. From 2006 to 2007, average PJM prices increased at a faster rate than did natural gas prices. The result is that average PJM prices in 2007 were very close to what they were in 2005, while natural gas-fired units experienced much lower marginal costs compared to 2005, meaning higher net revenue in 2007.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2007

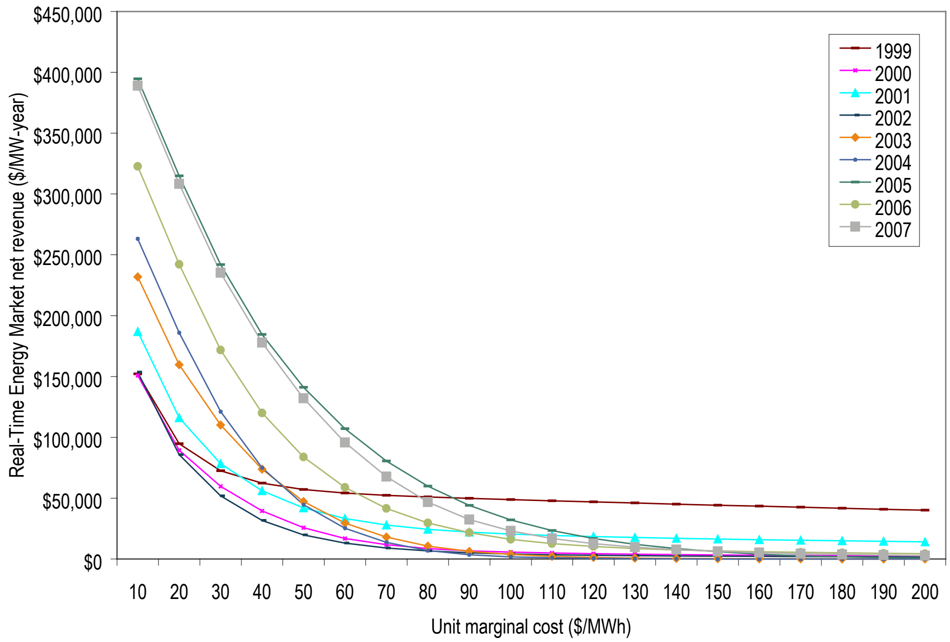
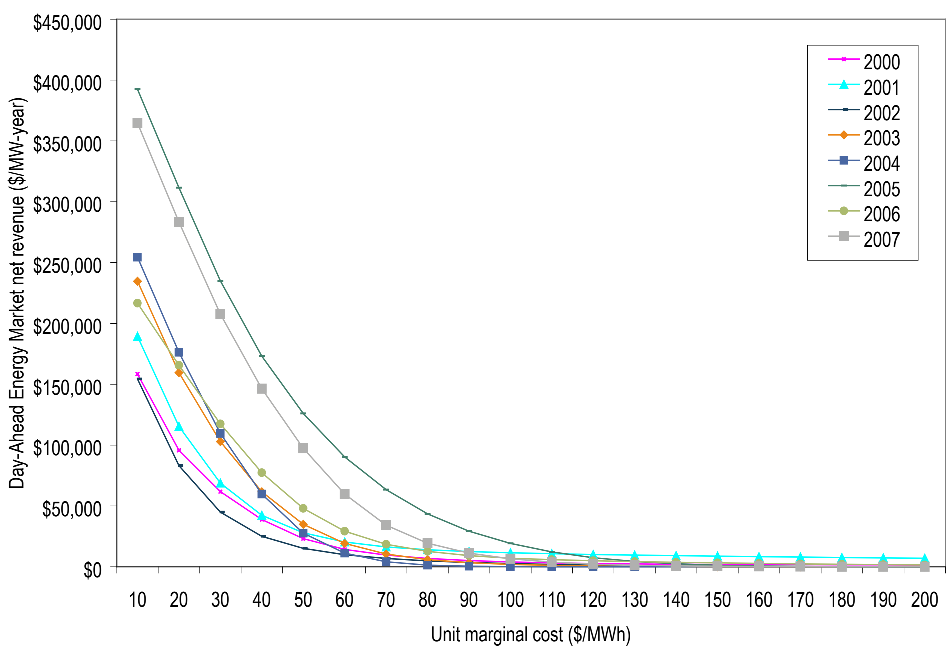


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2007



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.[11]

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and, as such, represent an upper bound of the markets' direct contribution to generator fixed costs. All 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.[12] 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 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.[13] 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

11 See the *2007 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.

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

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

three separate prices: RTO, which cleared at $40.80 per MW-day or $8,731 per MW for the remainder of calendar year 2007 or $14,892 per MW-year on an annualized basis; Eastern Mid-Atlantic Area Council (EMAAC), which cleared at $197.67 per MW-day or $42,301 for the remainder of 2007 and $72,150 per MW-year on an annualized basis; and Southwestern Mid-Atlantic Area Council (SWMAAC), which cleared at $188.54 per MW-day or $40,348 for the remainder of 2007 and $68,817 per MW-year on an annualized basis.

The 2007 zonal RPM prices, in effect from June 1, through December 31, 2007, are presented in Table 3-3 along with corresponding PJM control zones.

Table 3-3 PJM RPM auction-clearing capacity price by LDA: Effective for June 1, through December 31, 2007

LDA	$/MW-Day	$/MW in 2007 (7-Month)	PJM Zones Associated
RTO	$40.80	$8,731	AEP, ComEd, AP, Met-Ed, PENELEC, PPL, DLCO, DAY, Dominion
EMAAC	$197.67	$42,301	PSEG, PECO, RECO, AECO, DPL, JCPL
SWMAAC	$188.54	$40,348	Pepco, BGE

Table 3-4 shows capacity revenue for the nine-year period 1999 to 2007.[14] 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. 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 from Table 3-3 for the remaining seven months.[15] These capacity revenues are adjusted for the yearly, systemwide forced outage rate.[16]

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

15 The 2007 total revenue associated with capacity for PJM in Table 3-4 similarly combines load-weighted CCM and RPM revenues. The RPM revenue in this calculation 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.

16 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 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$4,199
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$5,345
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$15,318
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$4,706
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$4,199
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$5,255
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$4,199
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$12,061
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$12,061
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$15,318
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$12,061
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$11,233
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$14,440

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 years 1999 through 2007 in Table 3-5, were $4,284 per installed MW-year in 2007. 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.

Table 3-5 System average ancillary service revenue: Calendar years 1999 to 2007

	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

Generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $1,600 per installed MW-year in 2006 and were about $2,000 per installed MW-year in 2007. 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 assumes realistic, technology-specific operating constraints in order to provide a more accurate 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 discussed in this section are based on the economic dispatch scenario.

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues available 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 NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, a single heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator. The coal plant is a western Pennsylvania seam CP, equipped with lime injection for SO_2 reduction and low NO_x burners in conjunction with over fire air for NO_x control.

All net revenue calculations include the use of actual hourly ambient air temperature[17] and river water cooling temperature[18] and the effect of each, as applicable, on plant heat rates[19] and generator output for each of the three plant configurations.[20] 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.[21] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly to adjust for changes in energy production. For purposes of determining the amount of capacity that could be offered in the PJM Capacity Markets, the available capacity of each plant type was calculated based on actual ambient conditions at the hour of each annual peak load, consistent with PJM rules for determining available capacity. Available capacity was then 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 CCM for the months January through May and in the first RPM Auction for the months June through December.

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.[22] 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.[23] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a 15-continuous-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, $2.00 per MWh for the CC plant and $2.67 per MWh for the CP plant. These estimates were provided by a consultant to PJM and are based on quoted, third-party contract prices.[24] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[25] The burner tip fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[26] Coal burner tip cost was developed from the published prompt-month price, adjusted for rail transportation cost.[27] The average burner tip 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

17 Hourly ambient conditions supplied by Meteorlogix from the Philadelphia International Airport, Philadelphia, Pennsylvania.

18 Hourly river water conditions represent the Reedy Island Jetty Gauge station located on the Delaware 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>.

19 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 PJM.

20 Pasteris Energy, Inc.

21 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.

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

23 Outage figures obtained from the PJM eGADS database.

24 Pasteris Energy, Inc.

25 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.

26 Gas daily cash prices obtained from Platts.

27 Coal prompt prices obtained from Platts.

PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 synchronized reserve, but the 2007 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 since these plant types typically do not provide regulation service in PJM. 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 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. 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 2007, for CTs, the calculated rate is $2,154 per installed MW-year; for CCs, the calculated rate is $3,094 per installed MW-year and for CPs, the calculated rate is $2,350 per installed MW-year.[28]

Table 3-6 Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2007

	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

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2007 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. The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

28 The CT plant reactive revenues are based on 27 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 22 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on 12 recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2006 State of the Market Report* to include new generation filings.

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 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$24,903
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$3,746
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$7,109
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$24,754
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$6,050
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$3,637
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$35,242
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$24,083
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$5,293
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$22,812
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$20,675
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$20,859
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$12,918
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$25,855
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$17,474
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$22,194
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$13,367
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$16,401

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 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$64,017
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$21,406
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$36,435
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$60,126
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$31,600
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$20,534
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$94,631
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$60,080
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$20,743
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$58,572
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$52,834
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$53,733
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$37,448
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$61,720
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$47,242
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$62,212
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$61,378
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$44,403

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 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$176,717
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$141,191
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$179,296
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$173,141
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$135,304
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$134,797
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$275,943
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$173,967
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$122,602
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$168,637
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$161,337
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$164,189
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$139,039
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$176,047
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$153,907
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$179,610
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$229,411
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$147,038

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[29] for at least two hours during each four-hour block.[30] 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 credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.

29 Startup and shutdown fuel burns were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. 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. No-load costs are included in the heat rate.

30 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.

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-10 for the years 1999 through 2007. 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 the implementation of RPM.

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 2007

	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	$48,530

Table 3-11 shows the total net revenue (the Total column in Table 3-10) for the new entrant CT in each zone. For the nine-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $32,248 per installed MW-year.

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 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$41,774
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$9,919
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$14,283
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$41,434
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$12,742
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,047	$9,810
Dominion	NA	NA	NA	NA	NA	NA	NA	$30,782	$53,923	$42,353
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$40,953
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$9,360	$20,076	$11,465
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$39,683
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$34,263
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$37,729
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,228	$26,506
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,913	$42,534
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$31,062
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$39,064
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$26,065
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$32,248

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.[31] If there were not eight economic hours in any given day, then the CC was not 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 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 2007. 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 the implementation of RPM.

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 2007

	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

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 nine-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $61,085 per installed MW-year.

31 Startup and shutdown fuel burns obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platts fuel prices. Per PJM. "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2007), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements. 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 and off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

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 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$81,818
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$28,744
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$44,664
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$77,719
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$39,509
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$27,872
Dominion	NA	NA	NA	NA	NA	NA	NA	$83,104	$122,962	$103,033
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$143,274	$77,882
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$23,734	$44,520	$28,081
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$76,374
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$67,047
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$71,535
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$51,661
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$79,313
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$61,454
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$80,014
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$75,609
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$61,085

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.[32]

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-14 for the years 1999 through 2007. 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.

32 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, and at off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

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 2007

	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

Table 3-15 shows the total net revenue (the Total column 7 in Table 3-14) for the new entrant CP in each zone. For the nine-year period, the average total net revenue under the economic dispatch scenario was $164,977 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 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$118,254	$137,752	$143,257	$121,784	$179,116	$176,826	$306,995	$233,787	$345,738	$195,945
AEP	NA	NA	NA	NA	NA	NA	$150,175	$127,587	$170,532	$149,431
AP	NA	NA	NA	NA	$152,457	$123,619	$231,962	$178,701	$255,474	$188,443
BGE	$115,925	$124,106	$116,306	$119,714	$173,476	$148,096	$303,218	$248,763	$380,425	$192,225
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$144,104
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,420	$142,894
Dominion	NA	NA	NA	NA	NA	NA	NA	$240,827	$328,069	$284,448
DPL	$121,871	$149,239	$164,219	$125,338	$179,144	$160,036	$287,242	$213,261	$339,158	$193,279
DLCO	NA	NA	NA	NA	NA	NA	$126,378	$108,417	$157,544	$130,780
JCPL	$117,957	$129,968	$133,853	$110,646	$165,730	$186,316	$290,747	$203,776	$352,520	$187,946
Met-Ed	$116,776	$126,375	$126,885	$115,061	$167,367	$144,385	$276,295	$210,719	$311,759	$177,291
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,381	$326,717	$183,527
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,789	$155,139
Pepco	$115,585	$123,766	$110,089	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$195,171
PPL	$117,165	$125,227	$121,146	$105,991	$162,900	$136,364	$267,023	$201,584	$291,701	$169,900
PSEG	$120,910	$145,675	$142,694	$112,409	$184,332	$189,716	$316,131	$224,904	$353,386	$198,906
RECO	NA	NA	NA	NA	$186,859	$168,414	$298,795	$219,016	$347,309	$244,079
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$164,977

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.[33, 34] 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.

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 2007

	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$13,757
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,349
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$3,825
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$10,315
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$2,158
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,195
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$13,035
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$12,884
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$993
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$10,562
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$10,254
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$10,962
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$6,107
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$11,461
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$8,371
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$10,998
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$5,227
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$7,249

33 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.

34 The Day-Ahead Energy Market went into operation on June 1, 2000. For the analysis presented in Table 3-16, Table 3-17 and Table 3-18, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

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 2007

	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$54,334
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$14,124
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$26,817
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$44,874
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$19,322
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$12,379
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$69,020
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$49,702
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$11,306
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$46,726
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$41,312
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$44,445
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$28,249
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$47,719
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$36,737
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$50,855
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$49,127
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$31,869

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 2007

	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$179,343
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$134,283
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$171,058
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$172,255
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$130,474
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$124,616
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$252,852
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$180,777
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$117,399
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$172,666
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$165,482
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$172,337
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$143,449
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$176,531
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$159,399
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$183,828
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$218,861
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$149,430

For the eight-year period, the average PJM Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario for the CT plant was $7,249 per installed MW-year. For the CC plant, the eight-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $31,869 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 $149,430 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 37 percent higher than the Day-Ahead Market net revenue for the CT plant, 20 percent higher for the CC plant and 3 percent higher for the CP.[35]

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 2007

	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	$11,182	62%
Average	$11,500	$7,249	$4,252	37%

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 2007

	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	$2,632	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,195	20%
2006	$44,692	$31,670	$13,022	29%
2007	$66,616	$44,434	$22,182	33%
Average	$39,886	$31,869	$8,017	20%

35 The Day-Ahead Energy Market was initialized 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 2007

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,160)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,373)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,570	6%
2007	$244,419	$221,757	$22,662	9%
Average	$153,801	$149,430	$4,371	3%

Net Revenue Adequacy

To put the 2007 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 2007. The estimated, 20-year levelized fixed costs[36] are $90,656 per installed MW-year for the new entrant CT plant,[37] $143,600 per installed MW-year for the new entrant CC plant and $359,750 per installed MW-year for the new entrant CP plant.[38] 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 2007.[39] The increased costs of constructing generation facilities are the result of a combination of factors, including increased worldwide demand. For example, increased demand has caused significant increases in the cost of input materials as well as the actual cost of construction for gas-fired turbines, affecting fixed costs of both new entrant CTs and CCs.[40]

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
	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656
CC	$93,549	$99,230	$143,600
CP	$208,247	$267,792	$359,750

36 Annual fixed costs may vary by location. The fixed costs used here are based on a location in the PJM Mid-Atlantic Region.

37 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.

38 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2007.

39 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.

40 "Section 2, Budget Plant Prices," "Price Trends," *2007-08 Gas Turbine World Handbook* (Fairfield, Conn: Pequot Publishing, Inc.) Volume 26, p. 29.

In 2007, 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 $48,530 per installed MW-year. The associated operating costs were between $80 and $90 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $7.87 per MBtu and a VOM rate of $6.47 per MWh.[41] The average PJM net revenue in 2007 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.

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 2007

	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%
Average	$75,158	$32,248	43%

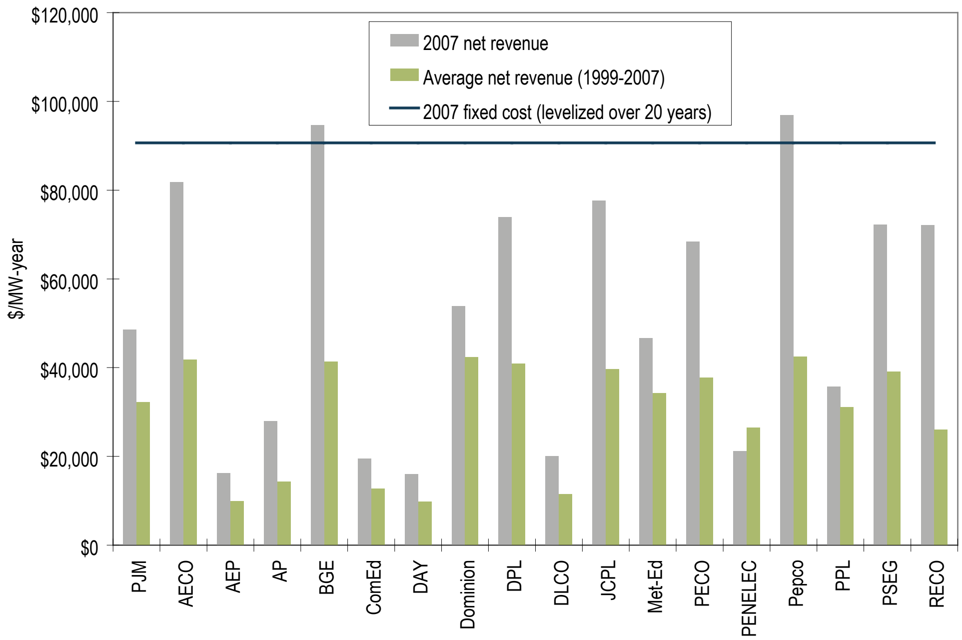
The 20-year levelized fixed cost for 2007 is compared to the economic dispatch net revenue for each zone for the period 1999 to 2007 in Table 3-24. While the average PJM net revenue is not enough to cover the 20-year levelized fixed costs, the net revenues in the Pepco Control Zone and in the BGE Control Zone are more than sufficient to cover the 2007 levelized fixed costs in 2007. Figure 3-3 summarizes the information in Table 3-24, showing the 2007 average net revenue for a new entrant CT, the zonal net revenue for the period 1999 to 2007 and the levelized 2007 fixed cost for a new entrant CT. For every zone except PENELEC, 2007 net revenues for a CT are greater than the nine-year average as the result of increased capacity payments and higher zonal LMPs.

41 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 2007

	2007			9-Year Average (1999-2007)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$81,801	$90,656	90%	$41,774	$75,158	56%
AEP	$16,230	$90,656	18%	$9,919	$75,158	13%
AP	$27,996	$90,656	31%	$14,283	$75,158	19%
BGE	$94,710	$90,656	104%	$41,434	$75,158	55%
ComEd	$19,542	$90,656	22%	$12,742	$75,158	17%
DAY	$16,047	$90,656	18%	$9,810	$75,158	13%
Dominion	$53,923	$90,656	59%	$42,353	$75,158	56%
DPL	$73,967	$90,656	82%	$40,953	$75,158	54%
DLCO	$20,076	$90,656	22%	$11,465	$75,158	15%
JCPL	$77,652	$90,656	86%	$39,683	$75,158	53%
Met-Ed	$46,663	$90,656	51%	$34,263	$75,158	46%
PECO	$68,376	$90,656	75%	$37,729	$75,158	50%
PENELEC	$21,228	$90,656	23%	$26,506	$75,158	35%
Pepco	$96,913	$90,656	107%	$42,534	$75,158	57%
PPL	$35,743	$90,656	39%	$31,062	$75,158	41%
PSEG	$72,221	$90,656	80%	$39,064	$75,158	52%
RECO	$72,112	$90,656	80%	$26,065	$75,158	35%
PJM	$48,530	$90,656	54%	$32,248	$75,158	43%

Figure 3-3 New entrant CT real-time 2007 net revenue, nine-year average net revenue and 20-year levelized fixed cost as of 2007 (Dollars per installed MW-year): Calendar years 1999 to 2007



In 2007, 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 $100,809 per installed MW-year. The associated operating costs were between $50 and $60 per MWh, based on a design heat rate of 7,150 Btu per kWh, average daily delivered natural gas prices of $7.87 per MBtu and a VOM rate of $2.00 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 2007. 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. Average 2007 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 2007

	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%
Average	$99,741	$61,085	61%

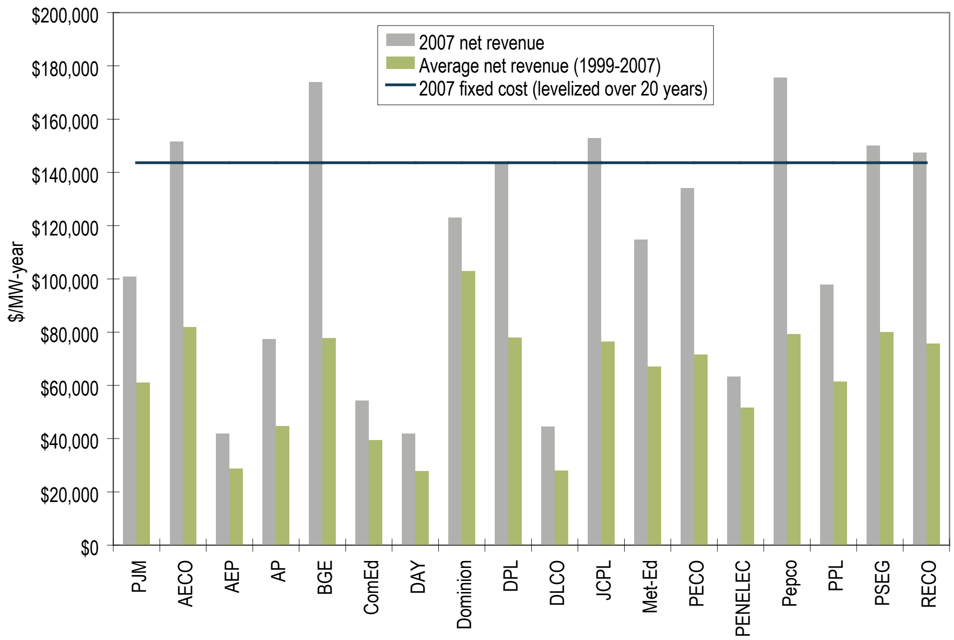
Economic net revenue for the new entrant CC is shown for each zone for the period 1999 to 2007 in Table 3-26, as is the 20-year levelized fixed cost for 2007. While the average PJM net revenue is not enough to cover the levelized fixed costs, the net revenue for the AECO, BGE, JCPL, Pepco, PSEG and RECO control zones is more than sufficient in 2007 to cover the 20-year levelized fixed costs and the net revenue in the DPL Control Zone is approximately equal to the 20-year levelized fixed costs. Figure 3-4 summarizes the information in Table 3-26, showing the 2007 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2007 by zone and the levelized 2007 capital cost for a new entrant CC.[42] For every zone, 2007 net revenues for a CC are greater than the nine-year average as the result of increased capacity payments and higher zonal LMPs.

42 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 2007

	2007			9-Year Average (1999-2007)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$151,617	$143,600	106%	$81,818	$99,741	82%
AEP	$41,958	$143,600	29%	$28,744	$99,741	29%
AP	$77,463	$143,600	54%	$44,664	$99,741	45%
BGE	$173,918	$143,600	121%	$77,719	$99,741	78%
ComEd	$54,257	$143,600	38%	$39,509	$99,741	40%
DAY	$41,992	$143,600	29%	$27,872	$99,741	28%
Dominion	$122,962	$143,600	86%	$103,033	$99,741	103%
DPL	$143,274	$143,600	100%	$77,882	$99,741	78%
DLCO	$44,520	$143,600	31%	$28,081	$99,741	28%
JCPL	$152,934	$143,600	107%	$76,374	$99,741	77%
Met-Ed	$114,824	$143,600	80%	$67,047	$99,741	67%
PECO	$134,069	$143,600	93%	$71,535	$99,741	72%
PENELEC	$63,257	$143,600	44%	$51,661	$99,741	52%
Pepco	$175,698	$143,600	122%	$79,313	$99,741	80%
PPL	$97,918	$143,600	68%	$61,454	$99,741	62%
PSEG	$149,965	$143,600	104%	$80,014	$99,741	80%
RECO	$147,431	$143,600	103%	$75,609	$99,741	76%
PJM	$100,809	$143,600	70%	$61,085	$99,741	61%

Figure 3-4 New entrant CC real-time 2007 net revenue, nine-year average net revenue and 20-year levelized fixed cost as of 2007 (Dollars per installed MW-year): Calendar years 1999 to 2007



In 2007, 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 $277,284 per installed MW-year. The associated operating costs were between $20 and $30 per MWh, based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.53 per MBtu and a VOM rate of $2.67 per MWh.[43] Table 3-27 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2007. 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. Average 2007 net revenue for a CP is the highest since the opening of PJM markets.

43 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 2007

	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%
Average	$231,697	$164,977	71%

The 2007 20-year levelized fixed cost is compared to economic dispatch, zonal net revenue from all markets for the new entrant CP for the period 1999 to 2007 in Table 3-28. While the average PJM net revenue is not enough to cover the 20-year levelized fixed costs, the net revenue for the BGE and the Pepco control zones is more than sufficient in 2007 to cover the 20-year levelized fixed costs and the net revenues in the AECO, JCPL, PSEG and RECO control zones are within 5 percent of the levelized fixed costs. Figure 3-5 summarizes the information in Table 3-28, showing the 2007 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2007 by zone and the levelized 2007 capital cost for a new entrant CP.[44] For every zone, 2007 net revenues for a CP are greater than the nine-year average as the result of increased capacity payments and higher zonal LMPs.[45]

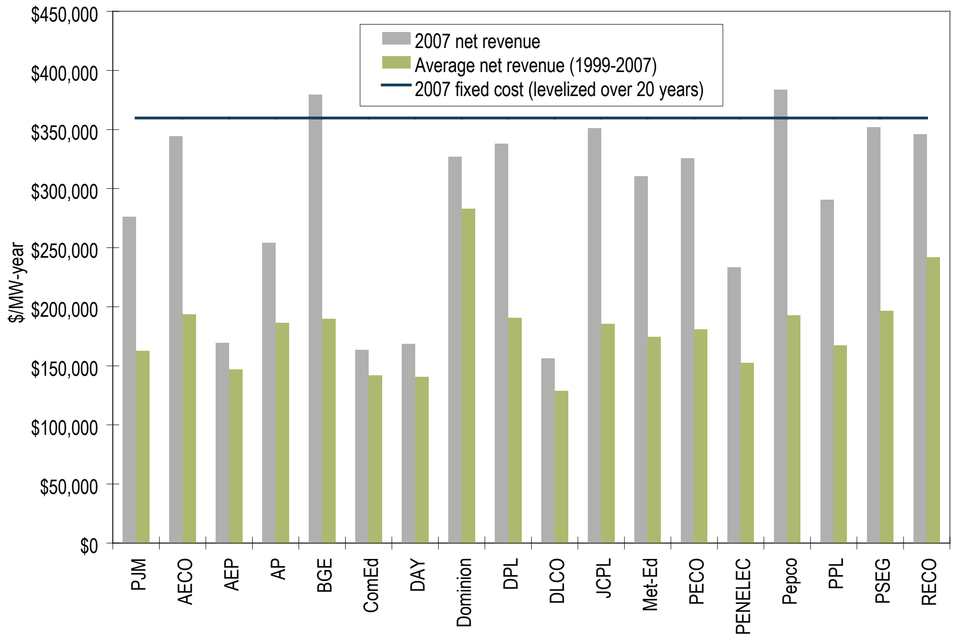
44 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

45 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 2007

	2007			9-Year Average (1999-2007)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$345,738	$359,750	96%	$195,945	$231,697	85%
AEP	$170,532	$359,750	47%	$149,431	$231,697	64%
AP	$255,474	$359,750	71%	$188,443	$231,697	81%
BGE	$380,425	$359,750	106%	$192,225	$231,697	83%
ComEd	$164,740	$359,750	46%	$144,104	$231,697	62%
DAY	$169,420	$359,750	47%	$142,894	$231,697	62%
Dominion	$328,069	$359,750	91%	$284,448	$231,697	123%
DPL	$339,158	$359,750	94%	$193,279	$231,697	83%
DLCO	$157,544	$359,750	44%	$130,780	$231,697	56%
JCPL	$352,520	$359,750	98%	$187,946	$231,697	81%
Met-Ed	$311,759	$359,750	87%	$177,291	$231,697	77%
PECO	$326,717	$359,750	91%	$183,527	$231,697	79%
PENELEC	$234,789	$359,750	65%	$155,139	$231,697	67%
Pepco	$384,940	$359,750	107%	$195,171	$231,697	84%
PPL	$291,701	$359,750	81%	$169,900	$231,697	73%
PSEG	$353,386	$359,750	98%	$198,906	$231,697	86%
RECO	$347,309	$359,750	97%	$244,079	$231,697	105%
PJM	$277,284	$359,750	77%	$164,977	$231,697	71%

Figure 3-5 New entrant CP real-time 2007 net revenue, nine-year average net revenue and 20-year levelized fixed cost as of 2007 (Dollars per installed MW-year): Calendar years 1999 to 2007



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 2007 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. Net revenue in 2007 was significantly above average as the result both of higher Energy Market net revenue and increased Capacity Market net revenue resulting from the RPM. Net revenue was higher than the fixed costs of generation in a number of zones as a result of locational pricing in both the Energy and Capacity Markets.

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 $5,000 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $20,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-29.[46]

46 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	$95,656	13.5%	$153,600	13.8%	$379,750	13.7%
Base Case	$90,656	12.0%	$143,600	12.0%	$359,750	12.0%
Sensitivity 2	$85,656	10.5%	$133,600	10.1%	$339,750	10.3%
Sensitivity 3	$80,656	8.8%	$123,600	8.1%	$319,750	8.5%
Sensitivity 4	$75,656	7.1%	$113,600	6.0%	$299,750	6.6%
Sensitivity 5	$70,656	5.2%	$103,600	3.7%	$279,750	4.5%
Sensitivity 6	$65,656	3.1%	$93,600	1.1%	$259,750	2.2%

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2007, PJM installed capacity rose slightly from 162,841 MW on January 1 to 163,498 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, 2007, PJM installed capacity was 162,840.7 MW.[47] (See Table 3-30.) Over the next five months, unit retirements, facility reratings plus import and export shifts changed installed capacity to 162,036.6 MW on May 31, 2007.[48]

47 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.

48 The capacity delineated herein is the capability of all PJM capacity resources used to serve load irrespective of their disposition in the RPM.

Table 3-30 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2007

	1-Jan-07		31-May-07		1-Jun-07		31-Dec-07	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,613.5	40.9%	66,418.9	41.0%	66,546.0	40.7%	66,286.0	40.5%
Oil	10,771.1	6.6%	10,657.5	6.6%	10,645.0	6.5%	10,640.0	6.5%
Gas	47,528.0	29.2%	46,955.9	29.0%	47,557.0	29.1%	47,599.4	29.1%
Nuclear	30,056.8	18.5%	30,056.8	18.5%	30,880.8	18.9%	30,883.8	18.9%
Solid waste	719.6	0.4%	719.6	0.4%	714.6	0.4%	712.6	0.4%
Hydroelectric	7,122.9	4.4%	7,193.9	4.4%	7,287.2	4.5%	7,311.2	4.5%
Wind	28.8	0.0%	34.0	0.0%	28.8	0.0%	65.4	0.0%
Total	162,840.7	100.0%	162,036.6	100.0%	163,659.4	100.0%	163,498.4	100.0%

At the beginning of the new planning year on June 1, 2007, installed capacity increased by 1,622.8 MW to 163,659.4 MW, a 1.0 percent increase in total PJM capacity over the May 31 level.

On December 31, 2007, PJM installed capacity was 163,498.4 MW.[49]

Energy Production by Fuel Source

In calendar year 2007, coal and nuclear units provided 89.2 percent, natural gas 7.7 percent, oil 0.5 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.2 percent of total generation. (See Table 3-31.)

Table 3-31 PJM generation (By fuel source (GWh)): Calendar year 2007

	GWh	Percent
Coal	416,180.7	55.3%
Oil	3,728.1	0.5%
Gas	57,825.8	7.7%
Nuclear	255,040.1	33.9%
Solid waste	4,896.0	0.7%
Hydroelectric	13,080.6	1.7%
Wind	1,345.8	0.2%
Total	752,097.2	100.0%

49 Wind-based resources accounted for 65.4 MW of installed capacity in PJM on December 31, 2007. This value represents approximately 20 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 20 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 80 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.

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 2007, 74,006 MW of capacity were in generation request queues for construction through 2016, compared to an average installed capacity of approximately 163,000 MW in 2007 and a year-end, installed capacity of 163,498 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.)

Table 3-32 Year-to-year capacity additions: Calendar years 2000 to 2007[50]

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

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 will be active through July 31, 2008.[51]

Capacity in generation request queues for the 10-year period beginning in 2007 and ending in 2016 increased by 27,621 MW from 46,272 MW in 2006 to 73,893 MW in 2007. (See Table 3-33.)[52, 53] Queued capacity scheduled for service in 2007 increased from 7,988 MW to 8,939 MW, or 12 percent. Queued capacity scheduled for service in 2008 increased from 9,705 MW to 11,636 MW, or 20 percent. Capacity

50 Values in the tables have been modified slightly because of accounting changes in information databases.

51 The dates of the RTEP feasibility studies were reported as the end dates of the queues in the *2005 State of the Market Report* instead of the actual start and end dates of the queues. Later, queue commencement and expiration dates were changed to reflect the correct dates. This change commenced with the *2006 State of the Market Report.*

52 See the *2006 State of the Market Report* (March 6, 2007), pp. 133-134, for the queues in 2006.

53 The 73,893 MW includes generation with scheduled in-service dates in 2007 and earlier years net of generation that is in-service earlier than scheduled.

in the queues for each of the years 2008 through 2014 also increased in 2007 over 2006. Queued capacity scheduled for service in 2015 and 2016 has not changed. In 2007, no projects were in queues projected to enter service later than 2016.

Table 3-33 Queue comparison (MW): Calendar years 2007 vs. 2006

	MW in the Queue 2006	MW in the Queue 2007	Year-to-Year Change (MW)	Year-to-Year Change
2007	7,988	8,939	951	12%
2008	9,705	11,636	1,931	20%
2009	4,575	10,377	5,802	127%
2010	7,436	11,464	4,028	54%
2011	5,935	17,653	11,718	197%
2012	4,159	5,520	1,361	33%
2013	1,600	1,660	60	4%
2014	0	1,770	1,770	NA
2015	3,234	3,234	0	0%
2016	1,640	1,640	0	0%
Total	46,272	73,893	27,621	NA

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. [54]

54 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, 2007[55]

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	4,638	0	15,882	20,520
C Expired 31-Jul-99	47	531	0	4,053	4,631
D Expired 31-Jan-00	0	768	0	7,069	7,837
E Expired 31-Jul-00	0	795	0	17,637	18,432
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	670	486	525	21,892	23,573
H Expired 31-Jan-02	0	259	443	8,424	9,126
I Expired 31-Jul-02	76	81	0	4,863	5,020
J Expired 31-Jan-03	0	36	155	707	898
K Expired 31-Jul-03	15	124	499	2,068	2,706
L Expired 31-Jan-04	0	66	666	3,548	4,280
M Expired 31-Jul-04	458	96	372	3,662	4,588
N Expired 31-Jan-05	2,413	1,922	158	5,275	9,768
O Expired 31-Jul-05	4,187	248	115	3,339	7,889
P Expired 31-Jan-06	6,433	393	14	2,122	8,962
Q Expired 31-Jul-06	14,225	0	5	1,312	15,542
R Expired 31-Jan-07	17,408	24	11	6,812	24,255
S Expired 31-Jul-07	22,134	20	0	300	22,454
T Expired 31-Jan-08	2,977	0	0	0	2,977
Total	71,043	19,472	2,963	130,345	223,823

Data presented in Table 3-34 show that 70 percent of total in-service capacity from all the queues was from Queues A and B and an additional 11 percent was from Queues C, D and E.[56]

The data presented in Table 3-34 show that for successful projects there is an average time of 1,047 days (i.e., 2.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 693 days (i.e., 1.9 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

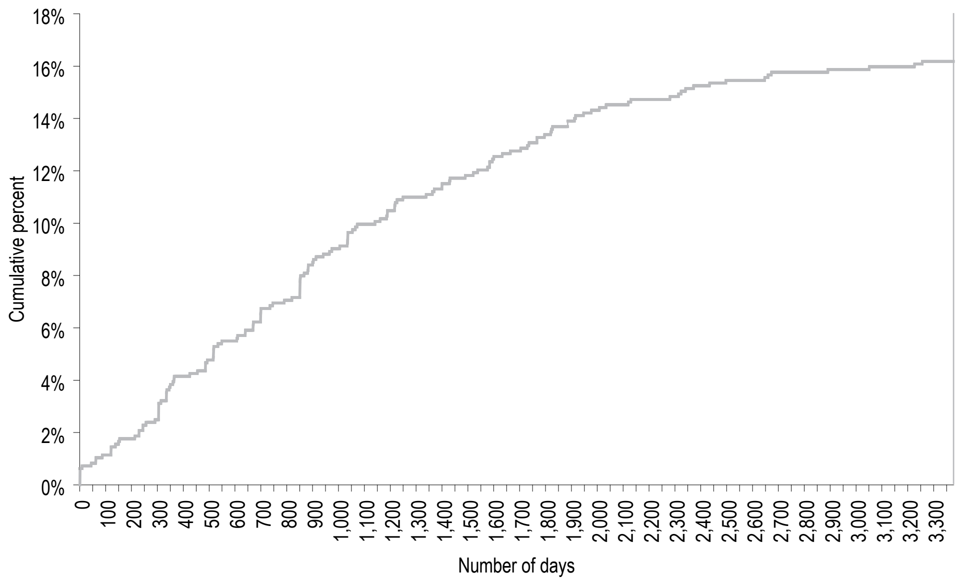
55 The *2007 State of the Market Report* contains all projects in the queue including reratings of existing generating units and energy only resources.
56 The data for Queue T include projects through December 31, 2007.

Table 3-35 Average project queue times: At December 31, 2007

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In-service	1,047	783	0	3,376
Under construction	1,433	455	517	2,524
Withdrawn	693	586	72	3,225
Active	604	379	152	3,255

Figure 3-6 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 3,376 days and this is the upper limit of Figure 3-6. The data show that about 10.0 percent of all projects in the queue are completed within 1,141 days and about 16.2 percent of the projects are completed within 3,376 days.

Figure 3-6 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, 2007, by unit type and control zone. Most (93 percent of the MW) of the steam projects (predominantly coal) and most of the wind projects (94 percent of the MW) are outside the Eastern MAAC (EMAAC)[57] and Southwestern MAAC (SWMAAC)[58] locational deliverability areas (LDAs).[59] Most (60 percent of the MW) of the combined-cycle (CC) projects are in EMAAC and SWMAAC. Wind projects account for approximately 25,211 MW of capacity

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

58 SWMAAC consists of the BGE and Pepco control zones.

59 See the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

or 34 percent of the capacity in the queues and CC projects account for 7,306 MW of capacity or 10 percent of the capacity in the queues.[60] Of the total capacity additions, only about 14,019 MW or 19 percent are projected to be in zones that are in EMAAC; about 7,892 MW or 11 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, 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	225	695	9	0	0	650	0	1,579
AEP	0	646	247	144	84	6,059	3,255	10,435
AP	640	600	11	81	0	1,955	2,268	5,555
BGE	0	961	8	0	3,280	0	0	4,249
ComEd	600	835	105	0	280	765	13,049	15,634
DAY	0	37	2	0	0	1,300	983	2,322
Dominion	1,633	1,235	148	94	1,944	280	0	5,334
DPL	0	305	23	0	0	653	1,598	2,579
JCPL	1,261	194	40	1	0	0	0	1,496
Met-Ed	47	1,200	66	0	0	0	0	1,313
PECO	550	4,540	6	0	140	0	3	5,239
PENELEC	0	153	12	32	0	310	2,778	3,285
Pepco	1,250	2,388	5	0	0	0	0	3,643
PPL	0	42	38	140	1,018	5,402	1,277	7,917
PSEG	1,100	1,909	74	0	43	0	0	3,126
UGI	0	0	0	0	0	300	0	300
Total	7,306	15,740	794	492	6,789	17,674	25,211	74,006

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 3-37) 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.

60 Since wind resources cannot be dispatched on demand, PJM rules require that the unforced capacity of these resources be derated by 80 percent until actual generation data are available. The derating of 25,200 MW of wind resources means that only 53,800 MW of capacity are effectively in the queue of the 74,000 MW currently active in the queues.

Table 3-37 Existing PJM capacity 2007 (By zone and unit type (MW))

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	14	0	0	1,108	8	1,813
AEP	4,361	3,577	0	1,008	2,093	21,711	0	32,750
AP	1,129	1,159	43	80	0	7,862	81	10,354
BGE	0	872	0	0	1,735	2,793	0	5,400
ComEd	1,790	6,172	0	0	11,448	6,916	343	26,669
DAY	0	1,316	44	0	0	4,079	0	5,439
DLCO	272	45	0	0	1,630	3,524	0	5,471
Dominion	2,515	3,213	105	3,321	3,459	8,332	0	20,945
DPL	1,088	801	86	0	0	1,780	0	3,755
External	0	100	0	0	0	5,605	0	5,705
JCPL	1,569	1,216	6	333	619	10	0	3,753
Met-Ed	1,984	417	0	19	786	817	0	4,023
PECO	2,497	1,498	6	1,618	4,492	2,022	0	12,133
PENELEC	0	332	50	476	0	6,805	119	7,782
Pepco	1,134	1,321	0	0	0	4,774	0	7,229
PPL	1,674	613	39	568	2,003	5,697	112	10,706
PSEG	2,849	2,975	13	8	3,353	2,264	0	11,462
Total	23,017	26,155	406	7,431	31,618	86,099	663	175,389

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 percent of all current MW, steam units 40 years of age and older comprise 87 percent of all MW 40 years of age and older and nearly 97 percent of such MW if hydroelectric is excluded from the total. Approximately 6,305 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	17,470	15,893	79	119	0	1,280	663	35,504
10 to 20	4,985	3,012	87	58	3,533	7,096	0	18,771
20 to 30	2	86	53	3,109	14,628	8,612	0	26,490
30 to 40	560	6,274	87	703	13,457	39,111	0	60,192
40 to 50	0	890	96	2,150	0	19,976	0	23,112
50 to 60	0	0	4	354	0	9,174	0	9,532
60 to 70	0	0	0	107	0	850	0	957
70 to 80	0	0	0	538	0	0	0	538
80 to 90	0	0	0	135	0	0	0	135
90 to 100	0	0	0	129	0	0	0	129
100 and over	0	0	0	29	0	0	0	29
Total	23,017	26,155	406	7,431	31,618	86,099	663	175,389

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 (CC and CT facilities) dominate the capacity additions, accounting for approximately 77 percent of the slated capacity additions. Steam additions (coal) account for about 9 percent of the MW and wind projects account for 11 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 the capacity additions in the SWMAAC LDA.

Table 3-39 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
EMAAC	3,136	7,643	152	1	183	1,303	1,601	14,019
Non-MAAC	2,873	3,353	513	319	2,308	10,359	19,555	39,280
SMAAC	1,250	3,349	13	0	3,280	0	0	7,892
WMAAC	47	1,395	116	172	1,018	6,012	4,055	12,815
PJM Total	7,306	15,740	794	492	6,789	17,674	25,211	74,006

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 2016. In 2016, CC and CT generators would account for 59 percent of EMAAC generation, an increase of 13 percentage points from 2007 levels. Accounting for the fact that about 700 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 38 percent to about 53 percent. This proportion of gas-fired capacity in EMAAC would increase to 54 percent if the 80 percent reduction for wind capacity is taken into account for EMAAC, meaning that the effective capacity additions are 12,738 MW.

The exact expected role of gas-fired generation depends largely on projects in the queues. Two coal projects in EMAAC totaling 1,280 MW face substantial site-related issues. There is a planned addition of 3,280 MW of nuclear capacity in SWMAAC.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 85 percent of all new capability in EMAAC and 94 percent when the 80 percent reduction for wind capability is included. In 2016 this would mean that CC and CT generators would comprise 61.2 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 2016 this would mean that CC and CT generators would comprise 54.5 percent of total capability in SWMAAC.

Table 3-40 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2016[61]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators All Ages	Percent of Area Total	Additional Capacity through 2016	Estimated Capacity 2016	Percent of Area Total
EMAAC	Combined cycle	0	0.0%	8,158	24.8%	3,136	11,294	26.4%
	Combustion turbine	606	10.3%	7,018	21.3%	7,643	14,055	32.9%
	Diesel	36	0.6%	125	0.4%	152	241	0.6%
	Hydroelectric	1,683	28.7%	1,959	6.0%	1	1,960	4.6%
	Nuclear	0	0.0%	8,464	25.7%	183	8,647	20.2%
	Steam	3,548	60.4%	7,184	21.8%	1,303	4,939	11.6%
	Wind	0	0.0%	8	0.0%	1,601	1,609	3.8%
	EMAAC Total	5,873	100.0%	32,916	100.0%	14,019	42,745	100.0%
Non-MAAC	Combined cycle	0	0.0%	10,067	9.4%	2,873	12,940	10.2%
	Combustion turbine	27	0.1%	15,582	14.5%	3,353	18,908	15.0%
	Diesel	39	0.2%	192	0.2%	513	666	0.5%
	Hydroelectric	1,335	6.2%	4,409	4.1%	319	4,728	3.7%
	Nuclear	0	0.0%	18,630	17.4%	2,308	20,938	16.6%
	Steam	20,250	93.5%	58,029	54.1%	10,359	48,138	38.1%
	Wind	0	0.0%	424	0.4%	19,555	19,979	15.8%
	Non-MAAC Total	21,651	100.0%	107,333	100.0%	39,280	126,297	100.0%
SWMAAC	Combined cycle	0	0.0%	1,134	9.0%	1,250	2,384	13.5%
	Combustion turbine	59	2.1%	2,193	17.4%	3,349	5,483	31.0%
	Diesel	0	0.0%	0	0.0%	13	13	0.1%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,735	13.7%	3,280	5,015	28.3%
	Steam	2,757	97.9%	7,567	59.9%	0	4,810	27.2%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	SWMAAC Total	2,816	100.0%	12,629	100.0%	7,892	17,705	100.0%
WMAAC	Combined cycle	0	0.0%	3,658	16.2%	47	3,705	11.7%
	Combustion turbine	198	4.8%	1,362	6.1%	1,395	2,559	8.1%
	Diesel	25	0.6%	89	0.4%	116	180	0.6%
	Hydroelectric	424	10.4%	1,063	4.7%	172	1,235	3.9%
	Nuclear	0	0.0%	2,789	12.4%	1,018	3,807	12.0%
	Steam	3,445	84.2%	13,319	59.2%	6,012	15,886	50.2%
	Wind	0	0.0%	231	1.0%	4,055	4,286	13.5%
	WMAAC Total	4,092	100.0%	22,511	100.0%	12,815	31,658	100.0%
All Areas	Total	34,432		175,389		74,006	218,405	

61 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.

2007 High-Load Events, Scarcity and Scarcity Pricing Events

In 2005 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.[62] PJM entered into a settlement in 2005 that was approved by the FERC and resulted in the implementation of administrative scarcity pricing rules in 2006.[63] August 8, 2007, was the first time that the administrative scarcity pricing rules were triggered. Table 3-41 provides the scarcity pricing events that occurred on August 8, 2007.

Table 3-41 2007 Scarcity pricing events[64]

	08-Aug-07	
Scarcity Region	Start	Stop
Bedington - Black Oak	1505	1812
Mid-Atlantic	1555	1733

PJM's administrative scarcity pricing mechanism was designed to ensure the appropriate tradeoff between limiting local market power and allowing market prices to reflect scarcity conditions.[65] 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 prespecified 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, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

The MMU's review of 2007 market results indicate that PJM's use of specific emergency procedures was an indicator of scarcity conditions. The analysis also leads to the recommendation that PJM's scarcity pricing mechanism be modified to incorporate a phased approach to scarcity and to incorporate nodal scarcity price signals and that PJM define additional scarcity pricing regions.

Definitions and Methodology

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

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

63 114 FERC ¶ 61,076 (2006).

64 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 12.

65 114 FERC ¶ 61,076 (2006).

66 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1".

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 analysis of scarcity constitutes a step toward a comprehensive analysis of scarcity. The MMU recommendations regarding scarcity pricing represent a step toward defining market rules.

In order to proceed with the analysis, terms must be carefully defined so that the results can be interpreted and so that the next steps in the analysis can be taken.

A high-load event is defined to exist when hourly demand, including the day-ahead operating reserve target, equals 90 percent or more of total, within-hour supply in the absence of non market administrative intervention. [67]

Scarcity is defined to exist when hourly demand, including the day-ahead operating reserve target, is greater than, or equal to, total, within-hour 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 within-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.

Within-hour, economic resources include the lesser of the hourly available ramp or remaining non-emergency capacity of synchronized resources and the lesser of hourly available ramp or available non-emergency capacity of non-synchronized resources with less than a one-hour startup time.[68]

The total system hourly operating reserve target is calculated based on the sum of the control-zone-specific, 30-minute, day-ahead reserve requirements as defined by PJM.[69] The definitions of high-load and scarcity events do not account for potential violations of aggregate, regional or zonal, 10-minute primary reserve requirements or 30-minute operating reserve targets. The definitions also do not account for utility or

67 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.

68 The methodology used to determine within-hour resources for this analysis tends to overestimate within-hour resources. For example, a unit's total within-hour ramp is presumed available from the first five-minute interval to the last, rather than being limited to the actual five-minute ramp rate within the hour. This means that a unit with a 100 MW ramp (i.e., with 100 MW capacity) is assumed to provide an average of 100 MW every minute of the hour. This methodology also overestimates available resources relative to the primary reserve requirement, as primary reserve resources must be available on less than a 30-minute basis. This measure also ignores transmission constraints that may limit deliverability to meet local load.

69 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.

participant-specific actions, such as interruption of non-firm load in accordance with applicable contracts or demand-side management measures that may be used to maintain system integrity.[70] Nonetheless, the net within-hour resource calculation provides a reasonable measure of overall system supply-demand balance. The basis of the control zone reserve requirements is shown in Table 3-42.

Table 3-42 Zone-specific operating reserve targets and requirements:[71, 72] Calendar year 2007

Control Zone	Region	Operating (Day Ahead)	Primary (Real Time)	Synchronized Reserve	Regulation
AP	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
AEP	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
DAY	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
ComEd	Western	MAIN ARS + Regulation	MAIN ARS	50% MAIN ARS	1% peak
Dominion	Southern	6% forecast load	VACAR ARS%	VACAR ARS%	1% peak
DLCO	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
PJM	Mid-Atlantic	Load dependent	1700 MW	Largest unit	1% peak

Non market, administrative tools available to PJM to ensure that demand does not exceed supply include calling for full emergency load response,[73] recalls of noncapacity-backed exports, loading of maximum emergency generation, voltage reductions,[74] emergency power purchases and manual load dump.[75] Of these steps, the last four are defined in the PJM Tariff as triggers for scarcity pricing events.[76]

In the MMU analysis, non market administrative tools applied by PJM in a given hour are used to adjust the measures of supply and demand to calculate the net supply condition that would have existed absent PJM intervention. The exception is the level of recallable energy exports from capacity resources. These are not included because PJM does not recall such energy in practice, for a variety of reasons. When PJM called full emergency load response, the associated load reduction is added to demand when calculating within-hour net resources. PJM-called emergency load response events in 2007 are shown in Table 3-43. When PJM directed the loading of maximum emergency generation, the value of the hourly maximum emergency generation loaded is subtracted from PJM total within-hour supply when calculating within-hour resources. When a maximum emergency alert is declared and the maximum emergency capacity is counted toward operating reserve targets by PJM, the added capacity is considered to be noneconomic for purposes of this analysis. Table 3-44 shows that maximum emergency generation alerts were declared and maximum

70 Only PJM-called interruptions of non-firm load in accordance with applicable contracts and PJM-called emergency demand response are used in the calculations.

71 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 12. ARS is automatic reserve sharing.

72 PJM triggers the "Contingency (also called Primary) Reserve Emergency Procedures" on the Mid-Atlantic Region based on a contingency or primary reserve requirement of 1,700 MW because of potential deliverability issues. Contingency or primary reserve requirements for the Reliability*First* Corporation (RFC) portion of the PJM footprint are 150 percent of the largest generators.

73 At the time of a call for full emergency load response, a PJM dispatcher also issues a NERC "Energy Emergency Alert Level 2" (EEA2) via the Reliability Coordinator Information System (RCIS) to ensure that all reliability authorities clearly understand potential and actual PJM system emergencies if one has not already been issued concurrent with the issuance of active load management curtailables/full emergency load response (formerly known as ALM). NERC EEA2 is issued when the following has occurred: Public appeals to reduce demand, voltage reduction and interruption of non-firm load in accordance with applicable contracts, demand-side management/active load management or utility load conservation measures. See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 19.

74 A voltage reduction warning (i.e., not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision 33 (Effective January 1, 2008), p. 24. Note that curtailment of nonessential building load is implemented prior to, or at this same time as, a voltage reduction action.

75 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."

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

emergency generation was loaded in one or more zones on August 8, 2007. When PJM called a voltage reduction, the value of the voltage reduction, in MW, is added to demand when calculating within-hour net resources. As shown in Table 3-45, PJM called a voltage reduction in one or more zones on August 8, 2007.

Table 3-43 PJM-called ALM: August 8, 2007[77]

	08-Aug-07	
	Effective Start	Stop
Short lead time Mid-Atlantic (BGE and Pepco sub-regions)	1320	1835
Long lead time (1 to 2 Hrs) Mid-Atlantic (BGE and Pepco sub-regions)	1344	1835
Short lead time Mid-Atlantic	1630	1750
Long lead time (1 to 2 Hrs) Mid-Atlantic	1408	1750
Short lead time Dominion		
Long lead time (1 to 2 Hrs) Dominion	1408	1835

Table 3-44 PJM-declared, maximum emergency events and maximum emergency generation loaded: August 8, 2007

	08-Aug-07	
	Start	Stop
Event declared BGE	1233	1812
Generation loaded BGE	1233	1812
Event declared Pepco	1233	1812
Generation loaded Pepco	1233	1812
Event declared Southern	1505	1812
Generation loaded Southern	1505	1812
Event declared Mid-Atlantic	1531	1733
Generation loaded Mid-Atlantic	1557	1733

77 While ALM has officially been changed to full emergency load response, operators were still, as of August 8, 2007, logging PJM-called emergency demand response as ALM.

Table 3-45 PJM-declared voltage reduction events: August 8, 2007

	08-Aug-07	
	Start	Stop
Mid-Atlantic Region	1555	1709
BGE and Pepco	1555	1759

2007 Results: High-Load and Scarcity Hours

As defined above, there were 157 high-load hours in 2007, of which 21 occurred in June, 40 occurred in July and 96 occurred in August. This number of high-load hours is more than twice the 70 high-load hours in 2006. Within these 157 hours, there were three hours, the hours beginning 1500 through 1700 on August 8, that met the criteria for potential within-hour scarcity.[78] PJM triggered its scarcity pricing events between 1505 and 1812. In 2006, 10 hours met the criteria for potential within-hour scarcity, but no scarcity events were triggered. There were 25 days in 2007 that met the criteria of a high-load day, up from the seven days recorded in 2006. The high-load days in 2007 were: June 1, 26 and 27; July 9, 10, 18, 26, 27, 30 and 31; and August 1 to 3, 6 to 10, 13, 15 to 17, 24, 28 and 29.[79]

Figure 3-7 shows the hourly loads of each high-load day relative to the average hourly summer load for 2007 and the hourly load of August 8, 2007.

78 Scarcity is considered to exist when hourly demand, including a total operating reserve requirement, is greater than, or equal to, total, within-hour supply in the absence of non market administrative intervention.

79 A high-load event is defined as a period during which real-time system load, plus the total of the system day-ahead operating reserve target, approaches a level that, in the absence of non market administrative intervention by PJM or a transmission zone, requires the use of 90 percent or more of total within-hour, available non-emergency resources in two or more hours in a given 24-hour period.

Figure 3-7 High-load day hourly load and summer average hourly load: June 2007 through August 2007

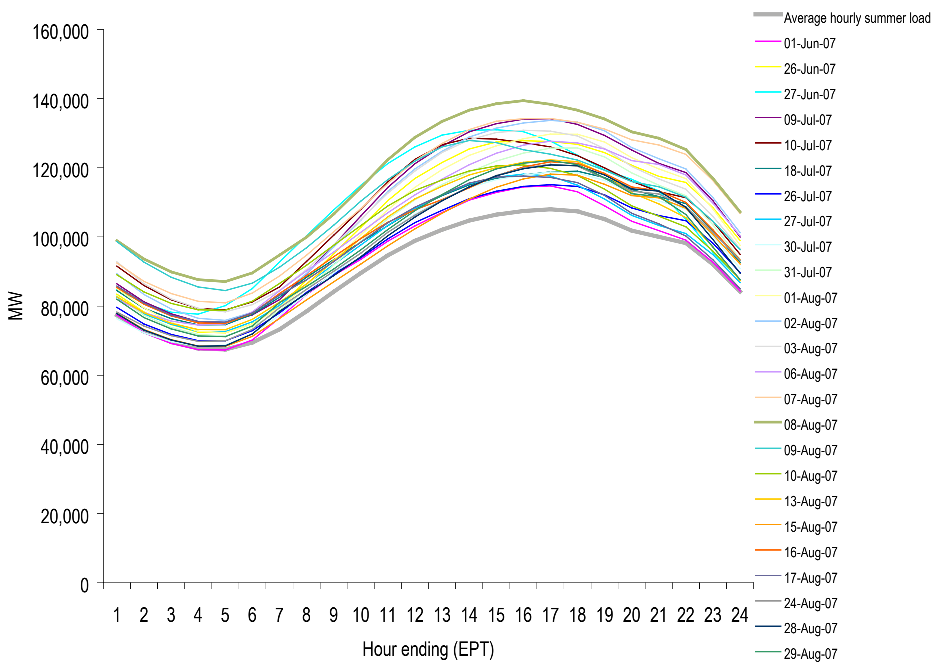


Figure 3-8 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand including the day-ahead operating reserve target for June 1, 26, and 27, 2007.[80, 81] Figure 3-8 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand, including the day-ahead operating reserve requirement for July 9, 10, 18, 26, 27, 30, and 31, 2007. Figure 3-9 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand, including the day-ahead operating reserve requirement for August 1 to 3, 6 to 10, 13, 15 to 17, 24, 28, and 29, 2007. In the figures, hours that meet the high-load definition are indicated by yellow bars, hours that meet the scarcity definition are indicated by red bars, and all other hours are indicated by green bars.

PJM took emergency action or made use of emergency resources on some of the days identified as high load. For example, PJM declared maximum emergency generation alerts for August 7, through August 9, 2007, for one or more zones. During this period available maximum emergency capacity was included in the calculation of operating reserve by PJM. On August 8, absent the inclusion of this capacity, PJM would have missed its day-ahead operating reserve target in one or more control zones for one or more hours. PJM operations recorded primary reserve warnings in one or more zones on August 8, 2007.

80 Load, as used here, is based on hourly eMTR loads in each hour, which are the simple average of the 12 five-minute interval loads in the hour for the total system.

81 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.

Figure 3-8 Net within-hour resources: June 1, 26, and 27, 2007

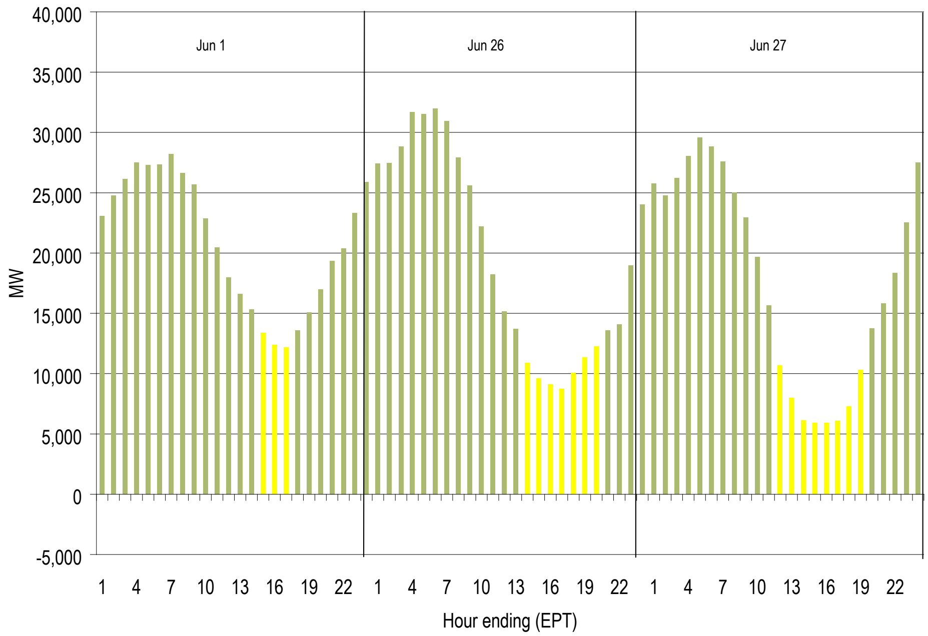


Figure 3-9 Net within-hour resources: July 9, 10, 18, 26, 27, 30, and 31, 2007

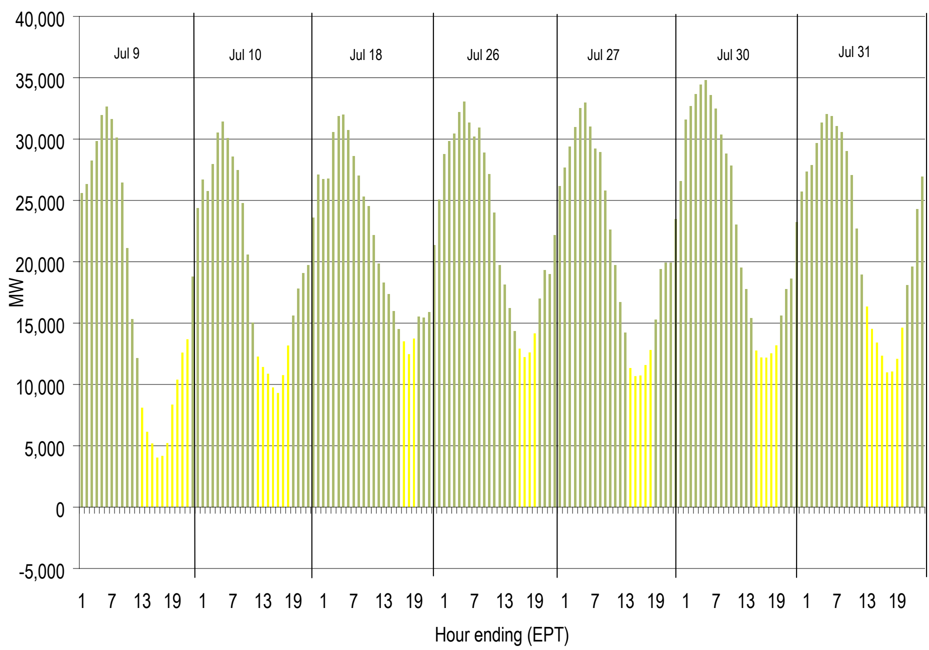


Figure 3-10 Net within-hour resources: August 1 to 3, August 6 to 10, August 13, August 15 to 17, August 24, 28, and 29, 2007

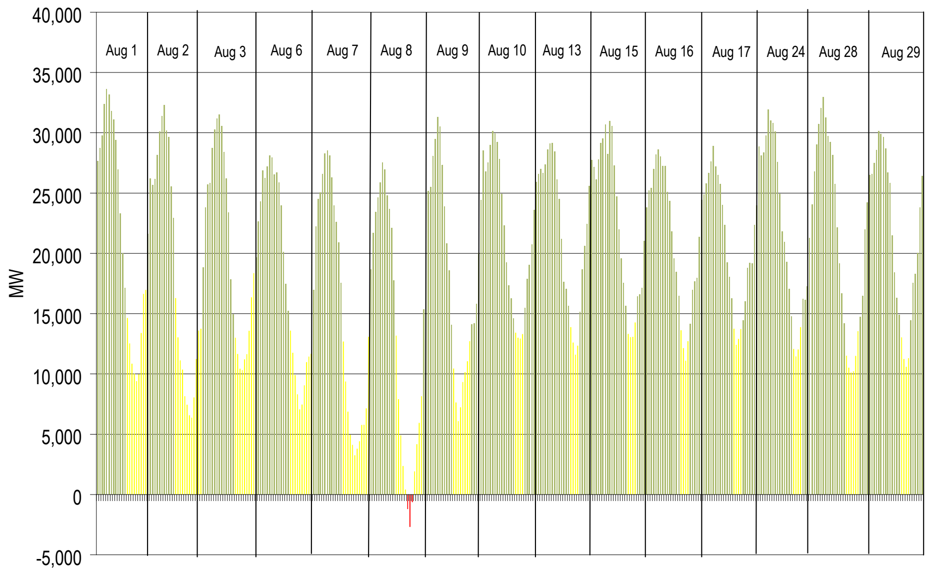
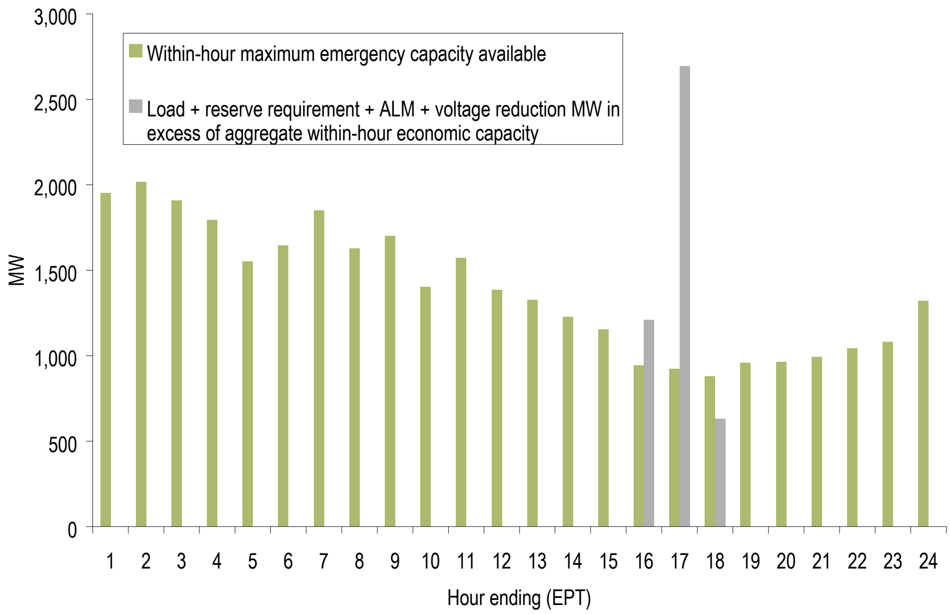


Figure 3-10 shows that hours ending 1600, 1700 and 1800 had negative net within-hour resources and therefore met the scarcity definition. Figure 3-11 shows the within-hour, available maximum emergency generation capacity, by hour and total hourly demand in excess of total within-hour economic supply for August 8. On that day, on an hourly aggregate basis, total demand, including the day-ahead operating reserve target, voltage reduction MW and ALM taken, caused PJM to be in a scarcity condition, as defined here, in hours beginning 1500, 1600 and 1700. PJM triggered its scarcity pricing events of August 8, 2007, during these same hours. (See Table 3-41.)

Figure 3-11 Within-hour maximum emergency capacity relative to hourly demand in excess of within-hour economic resources: August 8, 2007



Maximum emergency generation is generation capacity that PJM considers to be above the maximum economic level.[82] In concept, maximum emergency generation represents temporary MW additions to capacity made possible by operating a generator above its maximum economic capacity. In practice, the definition of maximum emergency generation in PJM is unclear and has been expanded beyond this scope to include environmental, fuel, temporary emergency conditions at the unit and other conditions which are declared to limit the availability of all or a portion of a unit's capacity. However, according to the PJM Tariff, during maximum emergency generation alerts the only capacity that can be designated as maximum emergency must fall into one of the following categories:

- Environmental Limits. If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.

- Fuel Limits. If physical events beyond the control of the unit owner result in the temporary interruption of fuel supply, and there is limited onsite fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement does not qualify as an event beyond the control of the unit owner.

- Temporary Emergency Conditions at the Unit. If temporary emergency physical conditions at the unit significantly limit its availability.

- Temporary MW Additions. If a unit can provide additional MW on a temporary basis by oil topping, boiler overpressure, or similar techniques and such MW are not ordinarily otherwise available.[83]

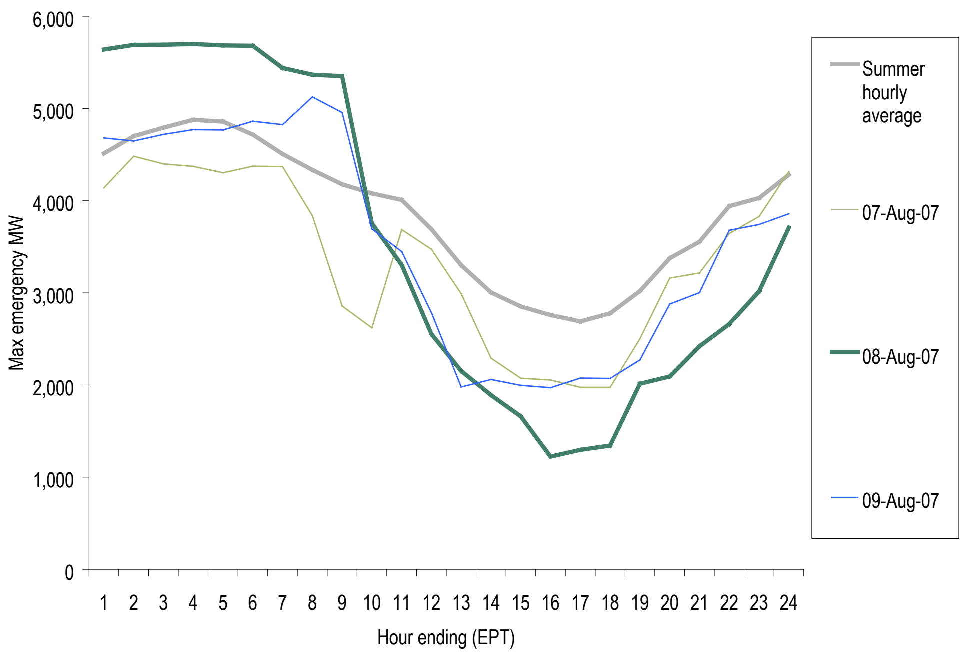
82 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 34.

83 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), pp. 73-74.

In the event of a declaration of a maximum emergency generation alert, generation owners are required, within PJM-specified time frames, to re-designate any maximum emergency capacity that does not meet the above criteria as economic capacity.[84]

Figure 3-12 shows the hourly comparison of declared maximum emergency capacity on days when maximum emergency generation alerts had been issued by PJM in one or more zones. On average, the capacity declared as maximum emergency generation capacity fell, consistent with the scarcity rules, during the high-load period of each day, relative to the summer average in each hour.

Figure 3-12 Comparison of hourly maximum emergency capacity on maximum generation alert days to the hourly summer average maximum emergency capacity: Summer 2007



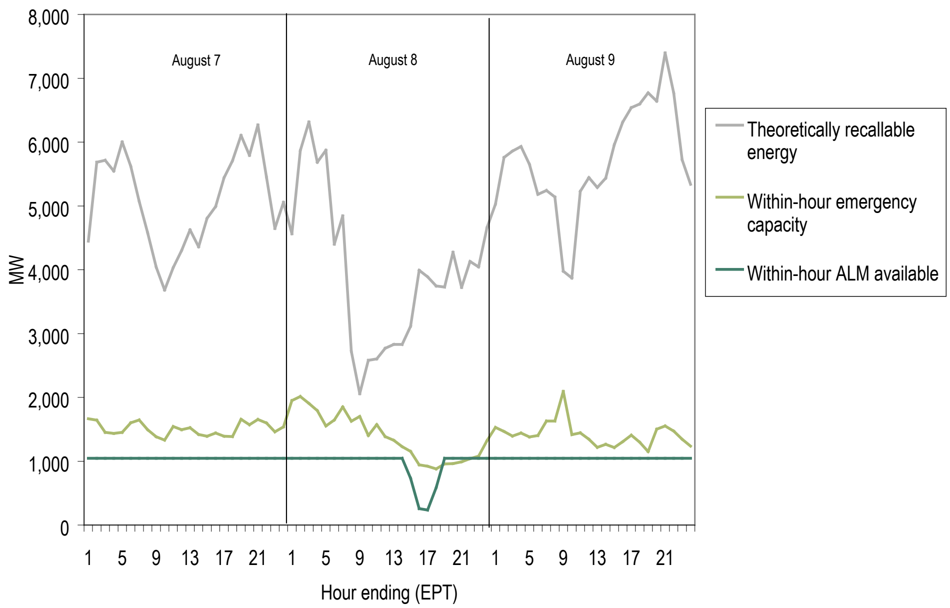
With the exception of potential emergency energy purchases and voltage reduction effects, Figure 3-13 shows each hour's within-hour available emergency resources for August 7, through August 9, 2007. The figure provides estimates of hourly recallable energy, within-hour available maximum emergency capacity and net remaining short-notification, emergency load response capacity.

Maximum emergency capacity available includes the lesser of the hourly available ramp or remaining emergency capacity from synchronized resources and the lesser of hourly available ramp or available capacity from non-synchronized, maximum emergency-only resources with less than a one-hour startup

84 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 74: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets."

time.[85] For purposes of determining the amount of energy available for emergency recall in a particular hour, total generation from delisted units is subtracted from exports in each hour. The result is a measure of recallable, export MW from PJM capacity resources. This calculated value is likely to be significantly larger than the total energy that could actually be recalled in an emergency. During times of significantly high load on a regional scale, if PJM operators believe that recalling energy could trigger reciprocal recalls from affected control areas, they will likely not recall the energy. All within-hour available generation values reflect available outage information. On the days in question, the most significant potential source of noneconomic capacity was available within-hour maximum emergency generation.

Figure 3-13 Within-hour emergency resources: August 7, to August 9, 2007



The peak PJM demand in 2007 was 139,428 MW in the hour ending 1600 on August 8, 2007. The peak PJM demand in 2006 was 144,644 MW in the hour ending 1700 on August 2, 2006. Despite the lower peak demand on August 8, 2007, the system was, on a net resource basis, tighter in 2007 than it had been on August 2, 2006. The difference in available resources is related, in part, to the level of outages on August 8, 2007, relative to those observed on August 2, 2006. Figure 3-14 provides the hourly MW of capacity forced out of service on August 8, 2007, and August 2, 2006. On an average hourly basis, August 8, 2007, had 2,726 MW more in forced outages than August 2, 2006. On an average hourly basis, the summer of 2007 had 1,126 MW more in forced outages than the summer of 2006.

85 The methodology used to determine within-hour resources for this analysis tends to overestimate within-hour resources. For example, a unit's total within-hour ramp is presumed available from the first five-minute interval to the last, rather than being limited to the actual five-minute ramp rate within the hour. This means that a unit with a 100 MW ramp (i.e., with 100 MW capacity) is assumed to provide an average of 100 MW every minute of the hour. This methodology also overestimates available resources relative to the primary reserve requirement as primary reserve resources must be available on less than a 30-minute basis.

Figure 3-14 Within-hour total forced outages: August 2, 2006, vs. August 8, 2007

2007 Scarcity Pricing Events

Four emergency messages trigger administrative scarcity pricing under the PJM Tariff. (See Table 3-46.)[86, 87] Two of these triggers were implemented in one or more zones on August 8, 2007. As shown in Table 3-44, PJM called for maximum emergency generation to be loaded in two contiguous transmission zones that are part of the Mid-Atlantic Scarcity Region (BGE and Pepco) between 1233 and 1812, in the entire the Mid-Atlantic Scarcity Pricing Region between 1557 and 1733 and in the Southern Region between 1505 and 1812. As shown in Table 3-45, PJM called for voltage reductions in two contiguous transmission zones that are part of the Mid-Atlantic Scarcity Pricing Region (BGE and Pepco) between 1555 and 1759 and in the entire Mid-Atlantic Scarcity Pricing Region between 1555 and 1709.

Based on these triggers for scarcity pricing, there were two concurrent scarcity pricing events declared by PJM on August 8, 2007: a scarcity pricing event for the Bedington — Black Oak Scarcity Pricing Region between 1505 and 1812 and a scarcity pricing event for the Mid-Atlantic Scarcity Pricing Region between 1555 and 1733. (See Table 3-41.)

86 "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.

87 114 FERC ¶ 61,076 (2006).

Table 3-46 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

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. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant.

In 2007, PJM did declare a scarcity pricing event for the hours identified by the MMU analysis during which supply was less than, or equal to, demand. This represents a clear improvement over 2006. The issues are whether there should be stages of scarcity pricing leading to the current definition of scarcity, whether scarcity pricing regions were defined correctly and whether a more nodal scarcity pricing mechanism is more consistent with LMP.

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 as early as 1408 in the Mid-Atlantic Scarcity Pricing Region and ended as late as 1750.

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.

This suggests that the definition of scarcity should include several stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff.

PJM should also consider adding new scarcity pricing regions. There would have been six hours of scarcity under PJM rules if BGE and Pepco had been defined to be a Scarcity Region. The PJM Tariff requires PJM to review the defined scarcity pricing regions and file changes (additions or deletions) to them with the Commission, as required.[88]

88 See PJM. "Open Access Transmission Tariff (OATT)," Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.03 (Effective January 27, 2006).

BGE and Pepco are two contiguous transmission zones containing generator buses with 5 percent, or greater, positive distribution factor relative to 500 kV, or greater, transmission constraints, including Bedington — Black Oak. If BGE and Pepco had been defined as a separate scarcity pricing region relative to Bedington-Black Oak and the Conastone Transformer, PJM's loading of maximum emergency generation in BGE and Pepco, to support the Bedington — Black Oak and the Conastone Transformer constraints, would have triggered a scarcity pricing event starting as early as 1233 and ending at 1812 on August 8, 2007.

The current administrative scarcity pricing rules result in a nonlocational 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. Nodal scarcity price signals, based on unit specific scarcity offers in the region, would permit individual generators to make decisions about their offers and would provide signals consistent with economic dispatch and locational pricing during the event.

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

- Stages of Scarcity Pricing. Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage could be either a clear measure of the level of available operating reserve or the progressive use of stronger emergency measures. For example, stages of scarcity pricing could be triggered by predefined levels of available operating reserve. For example, stages of scarcity pricing could be triggered by 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 noncapacity-backed exports, the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dumps in one or more contiguous transmission zones.

- Locational Price Signals. The single scarcity price signal should be replaced by locational signals. Locational signals could be implemented via scarcity offers submitted by generation owners. Generation owners could make explicit scarcity offers, in addition to their price and cost offers, which would be substituted for a unit's price offer for purposes of dispatch, setting LMP and payment when triggered by stages of scarcity declarations by PJM. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. Combined with a more refined set of scarcity triggers, this approach would also encourage participants to offer competitively under normal market conditions and competitively in the context of scarcity conditions.

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.

If a unit is selected to operate in the PJM Day-Ahead Energy Market but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, including startup and no-load, then day-ahead operating reserve credits ensure that all offer components are covered.[89] If a generator, scheduled to operate in the Real-Time Energy Market, operates as directed by PJM dispatchers but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, then balancing operating reserve credits ensure that all offer components are covered.

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.

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 increased in 2007 by 42.45 percent compared to 2006. The amount of balancing operating reserve credits paid to synchronous condensing increased by 176.79 percent compared to 2006, 17.49 percent of the total net increase. 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 concluded in 2006 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.

89 Operating reserve credits are also provided for pool-scheduled energy transactions, for generating units operating as condensers not as synchronized reserve, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons, for units performing black start tests and for units providing quick start reserve.

On November 15, 2007, after a lengthy but productive 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. PJM is expected to file the proposed changes with the FERC in 2008.

The revisions include the following 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.

- Parameter-Limited Schedule. 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 schedule.

- 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.

- 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.

- Regional Rates for Balancing Operating Reserve Charges. Operating reserve charges will be calculated regionally based on the charges accrued due to regional constraints.

- Allocation of Balancing Operating Reserve Charges. PJM will allocate operating reserve credits to real-time deviations from day-ahead schedules or to real-time load share plus export based on the reasons the credits were paid.

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 3-47 shows the categories of credits and charges and their relationship.

Table 3-47 Operating reserve credits and charges

Credits	Charges		
Day ahead:			
Day-Ahead Energy Market		Day-ahead demand	
Day-ahead congestion		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 from day-ahead schedules:	
Balancing congestion			
Lost opportunity cost			
Real-time import transactions			
	Day ahead		Real time
		Net deviations	
	Day-ahead decrement bids	Demand	Real-time load
	Day-ahead load		Real-time sales
	Day-ahead sales		Real-time export transactions
	Day-ahead export transactions		
	Day-ahead increment offers	Supply	Real-time purchases
	Day-ahead purchases		Real-time import transactions
	Day-ahead import transactions		
	Day-ahead scheduled generation	Generator	Real-time generation

Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market, day-ahead congestion and day-ahead import transaction credits.

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 3-49 shows monthly day-ahead operating reserve charges for calendar years 2006 and 2007.

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.[90]

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 3-49 shows monthly synchronous condensing charges for calendar years 2006 and 2007.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, balancing congestion credits, lost opportunity cost credits and real-time import transaction credits.[91] 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 canceled, pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

The 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 3-49 shows monthly balancing operating reserve charges for calendar years 2006 and 2007. These deviations fall into three categories and are calculated on an hourly net basis: demand, supply and generator deviations. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

- 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

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

91 PJM settlements do not differentiate balancing congestion credits and balancing energy market credits. Balancing congestion credits are defined here as operating reserve credits paid to units that were operated for a transmission constraint in the Real-Time Market or selected for a transmission constraint in the Day-Ahead Market. Balancing energy market credits are what remain in the balancing operating reserve credit category after accounting for credits for balancing congestion, real-time transactions and lost opportunity cost.

through the Enhanced Energy Scheduler (EES);[92] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[93] plus real-time exports scheduled through the EES.

- 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.

- 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.

Credit and Charge Results

Overall Results

Table 3-48 shows total operating reserve credits from 1999 through 2007, a period when significant market changes occurred.[94, 95] Total operating reserve credits increased by 42.45 percent in 2007.

Table 3-48 also shows the ratio of total operating reserve credits to the total value of PJM billings.[96] In 2007 this ratio did not change from the 1.5 percent of 2006. Over the last eight years, this ratio ranged from a low of 1.5 percent in 2006 and 2007 to a high of 9.6 percent in 2000.

Table 3-48 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2007

	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	62.05%	9.6%	$0.341	NA	$0.535	NA
2001	$290,867,269	34.05%	8.7%	$0.275	(19.5%)	$1.070	100.2%
2002	$237,102,574	(18.48%)	5.0%	$0.164	(40.4%)	$0.787	(26.4%)
2003	$289,510,257	22.10%	4.2%	$0.226	38.2%	$1.197	52.0%
2004	$414,891,790	43.31%	4.8%	$0.230	1.7%	$1.236	3.3%
2005	$682,781,889	64.57%	3.0%	$0.076	(66.9%)	$2.758	123.1%
2006	$322,315,152	(52.79%)	1.5%	$0.078	2.6%	$1.331	(51.7%)
2007	$459,124,502	42.45%	1.5%	$0.057	(27.0%)	$2.331	75.1%

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

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

94 Table 3-48 includes all categories of credits as defined in Table 3-47 and includes all PJM settlements' billing adjustments.

95 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 services.

96 See the *2007 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2002 to 2007," for a description of the value of total annual PJM billings during the period indicated.

Finally, Table 3-48 shows the total operating reserve credits per MWh for each full year since the introduction of the Day-Ahead Energy Market.[97] The day-ahead operating reserve rate decreased $0.021 per MWh or 27.0 percent from $0.078 per MWh in 2006 to $0.057 per MWh in 2007. The balancing operating reserve rate increased $1.00 per MWh, or 75.1 percent, from $1.331 per MWh in 2006 to $2.331 per MWh in 2007.

Table 3-49 compares monthly operating reserve charges by category for calendar years 2006 and 2007. While total operating reserve charges increased, the level of day-ahead operating reserve charges decreased by 22.38 percent between 2006 and 2007 and their share of total operating reserve charges decreased from 20.31 percent to 10.98 percent. Synchronous condensing operating reserve credits increased by 176.79 percent between 2006 and 2007.[98] Balancing operating reserve charges increased by 53.69 percent between 2006 and 2007 and their share of total operating reserve charges increased from 75.36 percent to 80.67 percent.

Table 3-49 Monthly operating reserve charges: Calendar years 2006 and 2007

	2006			2007		
	Day Ahead	Synchronous Condensing	Balancing	Day Ahead	Synchronous Condensing	Balancing
Jan	$7,145,655	$511,823	$16,216,936	$5,627,466	$2,001,215	$18,524,772
Feb	$4,525,771	$241,598	$14,107,994	$5,739,401	$2,670,396	$34,259,749
Mar	$4,924,985	$346,133	$7,992,131	$4,611,047	$1,300,459	$23,317,961
Apr	$5,368,796	$156,352	$7,575,039	$5,981,246	$1,208,114	$17,472,454
May	$6,129,196	$492,418	$11,837,289	$6,305,138	$1,584,887	$16,198,291
Jun	$4,383,153	$983,353	$18,003,134	$3,905,778	$2,706,483	$32,779,988
Jul	$4,838,992	$2,073,350	$43,756,738	$2,221,518	$4,374,349	$31,682,112
Aug	$5,045,827	$2,364,265	$49,491,691	$1,909,243	$7,495,702	$61,410,545
Sep	$6,765,877	$938,744	$14,273,544	$2,896,590	$5,046,901	$42,197,260
Oct	$5,244,729	$1,654,702	$12,890,522	$1,970,822	$5,024,503	$29,581,616
Nov	$4,191,905	$882,426	$16,465,964	$3,715,092	$3,332,124	$21,265,389
Dec	$4,929,665	$2,890,772	$23,017,897	$4,404,038	$721,130	$33,454,922
Total	$63,494,551	$13,535,936	$235,628,879	$49,287,379	$37,466,264	$362,145,059
Share of annual charges	20.31%	4.33%	75.36%	10.98%	8.35%	80.67%

Deviations

Real-time deviations from day-ahead schedules are used to allocate balancing operating reserve charges and are the denominator in the balancing operating reserve rate calculation. Table 3-50 shows monthly real-time deviations for demand, supply and generator categories for 2006 and 2007. Total deviations in the

97 In Table 3-48, "Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2007," numbers are based on PJM market settlements' data that include manual adjustments. The data in Table 3-49, Table 3-51, Table 3-55 and Figure 3-16 are based on the PJM market settlements' database and do not include manual adjustments.

98 Operating reserve credits to synchronous condensing increased because of the more frequent commitment of synchronous condensers for managing congestion in New Jersey. PJM operations shifted the assignment of these synchronous condensers from operating reserve to the Synchronized Reserve Market. See the *2007 State of the Market Report*, Volume II, Section 6, "Ancillary Service Markets."

demand and generator categories were lower in 2007 than in 2006 while total deviations in the supply category were higher in 2007. From 2006 to 2007, the share of total deviations in the demand category decreased by 4.01 percentage points, in the supply category rose by 3.58 percentage points and in the generator category increased by 0.42 percentage points.

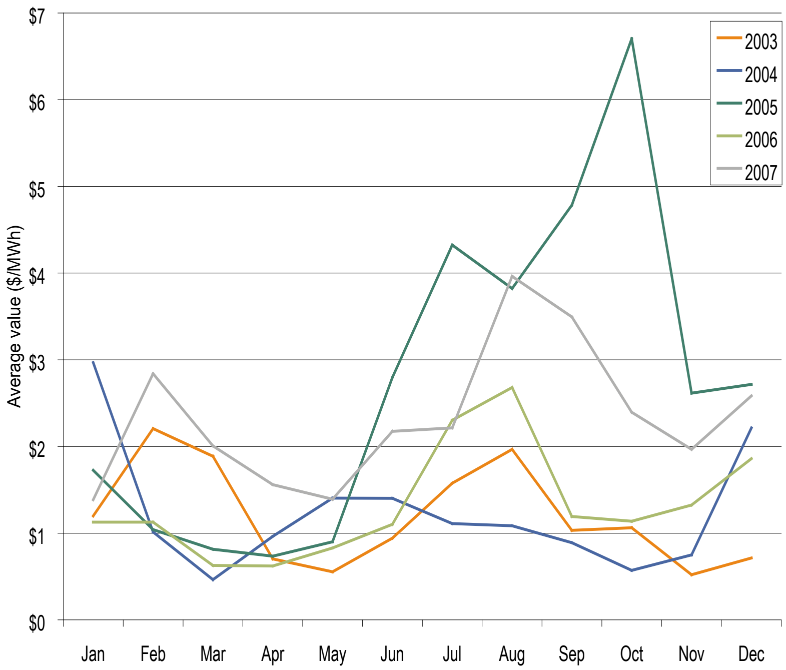
Table 3-50 Monthly balancing operating reserve deviations (MWh): Calendar years 2006 and 2007

	2006 Deviations			2007 Deviations		
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)
Jan	8,079,917	3,042,526	3,104,765	7,514,621	2,906,334	2,340,412
Feb	7,407,652	2,376,136	2,785,690	6,233,800	2,962,485	2,243,011
Mar	7,782,094	2,440,601	2,579,638	6,358,269	2,550,649	2,376,102
Apr	7,380,697	2,092,666	2,676,689	6,234,452	2,491,365	2,309,824
May	7,732,120	2,476,951	2,700,348	5,835,288	2,701,154	2,574,414
Jun	9,292,155	2,621,207	3,260,040	7,893,872	3,928,908	2,570,994
Jul	11,166,560	3,799,713	3,241,283	7,976,794	3,369,275	2,646,549
Aug	10,639,107	3,321,580	2,879,367	8,302,998	3,262,800	3,301,138
Sep	7,589,892	2,180,845	2,212,283	6,743,208	2,400,749	2,189,309
Oct	6,525,296	2,653,620	2,035,454	6,418,244	2,631,321	2,352,370
Nov	7,228,329	2,685,786	2,379,014	6,249,638	2,407,343	2,156,888
Dec	6,964,809	2,550,484	2,403,937	7,018,333	2,896,010	2,805,085
Total	97,788,628	32,242,115	32,258,508	82,779,517	34,508,392	29,866,097
Share of annual deviations	60.26%	19.87%	19.88%	56.25%	23.45%	20.30%

Balancing Operating Reserve Rate

The balancing operating reserve rate equals the total daily amount of balancing operating reserve credits divided by total daily deviations. It is calculated daily. Figure 3-15 shows monthly average balancing operating reserve rates for the past five years. A large increase in the monthly average balancing operating reserve rate occurred between June and October 2005. In 2007, the monthly average balancing operating reserve rate increased to an average of $2.33 per MW, which was higher than 2006 by $1 per MW.

Figure 3-15 Monthly average balancing operating reserve rate: Calendar years 2003 to 2007



Characteristics of Credits and Charges

Types of Units

Table 3-51 shows the proportion of total PJM installed capacity by unit type that received balancing operating reserve payments, the proportion of total MW capacity that received balancing operating reserve by unit type and the proportion of balancing operating reserve credits received by unit type.[99] In 2007, combustion turbine (CT) units received 59.49 percent of balancing operating reserve credits although they represented 21.31 percent of the capacity that received such credits and CTs that received balancing operating reserve credits represented 15.97 percent of total, PJM installed capacity. Steam units received 19.40 percent of balancing operating reserve credits, but represented 62.02 percent of the capacity that received such credits and steam units that received balancing operating reserve credits represented 46.47 percent of total PJM 2007 installed capacity. In 2007, units that received balancing operating reserve credits represented 74.93 percent of total installed PJM capacity.[100] In 2006, units that received balancing operating reserve credits had represented 78.62 percent of total installed PJM capacity.

99 In Table 3-51 balancing operating reserve credits include balancing congestion, balancing energy and lost opportunity cost credits. This table reflects a settlement adjustment for a hydroelectric unit.

100 The value of total PJM installed capacity used for these calculations was based on the amount recorded on June 1, 2007.

Table 3-51 Installed capacity percentage (By unit type receiving operating reserve payments): Calendar year 2007

Unit Type Receiving Operating Reserve Credits	Share of Total PJM Installed Capacity	Share of Capacity Receiving Operating Reserve Credits	Share of Balancing Operating Reserve Credits
Combined cycle	12.31%	16.43%	18.30%
Combustion turbine	15.97%	21.31%	59.49%
Diesel	0.19%	0.25%	2.81%
Hydroelectric	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%
Steam	46.47%	62.02%	19.40%
Total	74.93%	100.00%	100.00%

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.[101]

Table 3-52 shows the percentage of total PJM self-scheduled generation, economic generation, noneconomic generation and regulation generation for 2007.

Table 3-52 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2007

	All Hours	On Peak	Off Peak
Self-scheduled generation	46.13%	44.99%	48.84%
Economic generation	47.59%	50.92%	39.72%
Noneconomic generation	4.98%	3.59%	8.26%
Regulation generation	1.30%	0.50%	3.18%
Total	100.00%	100.00%	100.00%

101 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 for each unit type. For example, in 2007 steam units represented 92.65 percent of all economic generation. Table 3-54 presents the share of each unit type for self-scheduled, economic, noneconomic and regulation generation. For example, in 2007 48.34 percent of steam unit generation was economic.

Table 3-53 PJM generation by unit type receiving operating reserve payments: Calendar year 2007

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.66%	5.64%	24.11%	8.54%
Combustion turbine	0.34%	0.89%	8.90%	1.40%
Diesel	0.17%	0.02%	0.12%	0.00%
Hydroelectric	2.97%	0.80%	0.00%	0.00%
Steam	92.65%	92.65%	66.87%	90.05%
Wind	0.22%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%

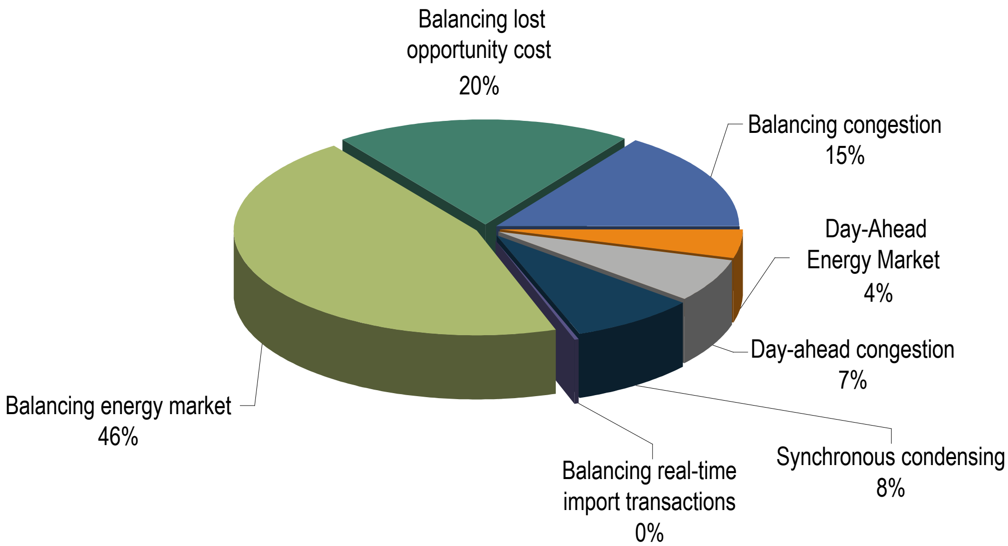
Table 3-54 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2007

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	29.63%	47.29%	21.13%	1.95%	100.00%
Combustion turbine	14.97%	40.68%	42.59%	1.75%	100.00%
Diesel	84.64%	8.64%	6.72%	0.00%	100.00%
Hydroelectric	78.24%	21.76%	0.00%	0.00%	100.00%
Steam	46.73%	48.34%	3.65%	1.28%	100.00%
Wind	99.39%	0.61%	0.00%	0.00%	100.00%

Operating Reserve Credits by Category

Figure 3-16 shows that the largest share of total operating reserve credits, 45.23 percent, was paid to resources in the balancing energy market during 2007 and that 80.68 percent of total operating reserve credits was in the balancing category. Figure 3-16 also shows that 4.21 percent of total operating reserve credits was paid to resources in the Day-Ahead Energy Market and that 10.98 percent of total operating reserve credits was in the day-ahead category.[102]

Figure 3-16 Operating reserve credits: Calendar year 2007



Geography of Balancing Credits and Charges

Table 3-55 compares the share of balancing operating reserve charges paid by and credits paid to generators located within the Mid-Atlantic Region to the share of charges paid by and credits paid to generators located within all other PJM control zones.[103] The other control zones include those in the Western Region (i.e., the AEP, AP, ComEd, DAY and DLCO control zones) and in the Southern Region (i.e., the Dominion Control Zone). On average, 46.97 percent of all generator charges were paid by generators in the Mid-Atlantic Region. On average, 61.72 percent of energy credits, 84.78 percent of congestion credits and 20.61 percent of lost opportunity cost credits were paid to generators in the Mid-Atlantic Region. Table 3-55 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 16.40 percent of all operating reserve charges and generator credits were 78.81 percent of all operating reserve credits.

These results do not necessarily mean that there is an inappropriate regional allocation of operating reserve charges but reflect the usage of actual resources to meet the need for system operating reserve.

102 There were no day-ahead import transactions in 2007 that received operating reserve credits.

103 Balancing operating reserve charges in Table 3-55 include only those in the generator category. Balancing operating reserve credits in Table 3-55 include balancing energy market credits, balancing congestion credits and lost opportunity cost credits. Categories are defined in Table 3-47.

Table 3-55 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2007

	Mid-Atlantic Region				Other Control Zones					
	Generation Charge	Energy Credit	Congestion Credit	Lost Opportunity Cost	Generation Charge	Energy Credit	Congestion Credit	Lost Opportunity Cost	Generation Charges Share of Total Operating Reserve Charges	Generation Credits Share of Total Operating Credits
Jan	46.53%	64.05%	93.74%	20.33%	53.47%	35.95%	6.26%	79.67%	14.11%	70.83%
Feb	43.98%	58.83%	93.05%	12.67%	56.02%	41.17%	6.95%	87.33%	16.56%	80.19%
Mar	54.05%	59.26%	65.97%	26.59%	45.95%	40.74%	34.03%	73.41%	16.92%	79.78%
Apr	52.16%	52.95%	85.45%	16.11%	47.84%	47.05%	14.55%	83.89%	15.19%	70.85%
May	49.31%	38.26%	87.96%	38.36%	50.69%	61.74%	12.04%	61.64%	15.67%	67.16%
Jun	41.37%	62.70%	69.77%	18.97%	58.63%	37.30%	30.23%	81.03%	16.02%	83.21%
Jul	47.61%	67.52%	71.67%	18.80%	52.39%	32.48%	28.33%	81.20%	15.89%	82.77%
Aug	45.01%	69.90%	85.37%	20.53%	54.99%	30.10%	14.63%	79.47%	20.03%	86.72%
Sep	43.25%	63.01%	73.28%	11.60%	56.75%	36.99%	26.72%	88.40%	16.03%	84.16%
Oct	51.64%	61.84%	94.22%	12.40%	48.36%	38.16%	5.78%	87.60%	16.84%	80.88%
Nov	48.36%	71.92%	97.42%	22.52%	51.64%	28.08%	2.58%	77.48%	14.19%	73.95%
Dec	40.43%	70.38%	99.48%	28.44%	59.57%	29.62%	0.52%	71.56%	19.30%	85.22%
Average	46.97%	61.72%	84.78%	20.61%	53.03%	38.28%	15.22%	79.39%	16.40%	78.81%

Market Power Issues

The exercise of market power by units that are paid operating reserve credits is also a contributor 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 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. In addition, the exemption of units from local market power mitigation rules should be terminated if they exercise market power which is reflected in operating reserve credits rather than directly in LMP.

PJM's anticipated filing of changes to the operating reserve rules, if accepted by the FERC, will address the issues related to operating parameters when PJM also makes appropriate modifications to the way in which it defines markets for operating reserve.

Top 10 Units

A disproportionate share of balancing and day-ahead operating reserve credits has been paid to a small number of units and companies since 2001. This continued to be the case in 2007. As Table 3-56 shows, the top 10 units, less than 1 percent of all units, received 29.75 percent of total operating reserve credits in 2007, a small increase over the 29.72 percent in 2006. The top 20 units received 39.8 percent of operating reserve credits in 2007 and 36.9 percent in 2006. In 2007 five companies owned the top 10 units. In 2006, the top 10 units were owned by four companies. In 2006, the top generation owner received 16 percent of the total operating reserve credits paid, and in 2007, the top generation owner received 8 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 2007

	Percent	Top 10 Units 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%

Markup

Unit Markup - Top 10 Units

To determine the contribution that unit price offers, in excess of cost, make to operating reserve payments, the MMU performed a markup analysis of the top 10 units.[104] As Table 3-57 shows, the markup for the top 10 units averaged 45.8 percent in 2007, a substantial increase over prior years with the exception of 2005 when the markup for the top 10 units averaged 75.4 percent. The markup for the top 10 units is a weighted-average, whose weights are generator output when operating reserve credits are paid.

The generation owner with the largest share of top 10 credits received 47.82 percent of Energy Market operating reserve credits paid to the top 10 units and had a weighted-average markup of 0 percent in 2007. The next generation owner received 30 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 33.7 percent and the third generation owner received 13 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 126.5 percent in 2007. In 2006 the top owner received 69 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 0 percent.

104 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

For each year 2001 to 2006, 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. The CT unit accounted for the smallest share of the operating reserve credits received by the top 10 units in 2007, representing 4.2 percent of the credits. Steam units represented 18.2 percent of the credits received by the top 10 in 2007. CC units accounted for a larger share of the operating reserve credits received by the top 10 units in 2007, representing 77.6 percent of the credits received by the top 10 in 2007, as shown in Table 3-57.

Table 3-57 Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2007

	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%

Unit Markup - All Units

PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. Five of the top 10 units are exempt from offer capping for local market power.[105] Table 3-58 shows the simple average markup for generators exempt from offer capping, for generators not exempt from offer capping and for all generators, when balancing operating reserve credits were paid.[106] For all units, when operating reserve credits were paid, the markup for exempt units was almost three times higher than the markup for non-exempt units, 19 percent for exempt units and 7 percent for non-exempt units. The associated maximum markups exceeded the average levels by a substantial amount; the maximum markup for an exempt unit was in excess of 700 percent.[107]

Table 3-58 Simple average generator markup: Calendar year 2007

Unit Class	Exempt	Non-Exempt	All Units
All units	19%	7%	8%
CC	28%	(10%)	1%
CT	14%	11%	11%
Diesel	14%	6%	7%
Steam	NA	0%	0%

105 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Exempt Unit Markup."

106 The weighted-average markup calculations are weighted by real-time generation.

107 For calendar year 2006 this percentage was in excess of 1,300 percent. There was an error in the *2006 State of the Market Report*, which showed 130 percent.

Impact of Markup by Exempt Units

Table 3-59 compares the total balancing operating reserve rate and the balancing operating reserve rate adjusted to remove all markups above 10 percent for exempt units.[108] This comparison shows the impact on operating reserve charges of markups over cost by units exempt from offer-capping rules. The impact is the result of increased markups by the 43 exempt units that received balancing operating reserve credits in 2007.[109] If the exempt units had been subject to offer-capping rules at the times they were paid operating reserve credits, the cumulative current total balancing operating reserve credit in 2007 would have been lower by about $35 million and the balancing operating reserve rate in 2007 would have been 9.85 percent lower.

Table 3-59 Balancing operating reserve rate for exempt units (Actual and markup-adjusted): Calendar year 2007

	Current Rate	Markup-Adjusted Rate
Jan	1.38	1.29
Feb	2.84	2.48
Mar	2.01	1.79
Apr	1.56	1.41
May	1.39	1.34
Jun	2.18	2.01
Jul	2.21	2.04
Aug	3.96	3.60
Sep	3.49	3.09
Oct	2.40	2.16
Nov	1.97	1.73
Dec	2.58	2.27
Annual average	2.33	2.10

108 The MMU estimates the costs for exempt units because such units are not required to submit cost-based offers to PJM. All markup results for exempt units are based on the MMU cost estimates.

109 These are the units that received balancing energy and balancing congestion credits.

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 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.

This issue will be addressed if PJM's proposed modifications to the operating reserve rules are accepted by the FERC.