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 2006. 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.

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[1]

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.

  Analysis of 2006 net revenue, including both the Day-Ahead and Real-Time Energy Market, indicates that the fixed costs of new peaking, midmerit and coal-fired baseload were not fully covered. During the eight-year period 1999 to 2006, the data lead to the conclusion that net revenues were less than the fixed costs of generation and that this shortfall resulted both from lower, less volatile energy market prices and lower capacity credit market prices in the last several years.

  Under an economic dispatch scenario, the eight-year net revenue averaged $30,212 per installed MW-year for a new entrant combustion turbine (CT) plant, $56,120 per installed MW-year for a new entrant combined-cycle (CC) plant and $150,939 per installed MW-year for a new entrant pulverized coal (CP) plant. Thus, under perfect economic dispatch over the eight-year period, the average, net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

- **Zonal Net Revenues.** Zonal revenues reflect differentials in locational marginal price (LMP) across the system and illustrate the substantial impact that locational prices have on economic incentives. For a CT, while the PJM average net revenue in 2006 was $10,996 per MW-day, the maximum zonal CT net revenue was $37,801 in the PEPCO control zone and the minimum was $4,342 in the DAY control zone. For a CC, while the PJM average net revenue in 2006 was $44,692 per MW-day, the maximum

1 For additional information on PJM's footprint and the definition of these phases, see *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

zonal CC net revenue was $91,120 in the PEPCO control zone and the minimum was $18,897 in the DLCO control zone. For a CP, while the PJM average net revenue in 2006 was $177,852 per MW-day, the maximum zonal CP net revenue was $254,964 in the PEPCO control zone and the minimum was $102,923 in the DLCO control zone.

While the maximum zonal CT net revenue was well below the annual fixed costs of a new CT, the maximum CC zonal net revenue was close to the annual fixed costs of a new CC and the maximum CP zonal net revenue was substantially in excess of the annual fixed costs of a new CP. Thus, the higher LMPs in the eastern PJM zones, reflecting transmission limitations and congestion, have a positive impact on the incentive to invest in those areas.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2006, PJM installed capacity remained relatively flat with the exception of modest changes in imports and exports. Retirements were offset by new additions and the installed capacity on December 31, 2006, was only 884 MW less than on January 1, 2006.

- **PJM Installed Capacity by Fuel Type.** At the end of 2006, PJM installed capacity was 162,143 MW. Of the total installed capacity, 41.0 percent was coal, 29.0 percent was natural gas, 18.5 percent was nuclear, 6.6 percent was oil, 4.4 percent was hydroelectric and 0.4 percent was solid waste.

- **Generation Fuel Mix.** During 2006, coal was 56.8 percent, nuclear 34.6 percent, natural gas 5.5 percent, oil 0.3 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 0.1 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.** During the summer of 2006, there were 70 hours of high load that occurred from July 17 through July 19, from July 31 through August 3 and on August 7. Within these 70 hours, there were 10 hours on August 1 and August 2 that met the criteria for potential within-hour scarcity.

- **Scarcity Pricing Events in 2006.** PJM implemented administratively based, scarcity pricing rules in 2006.[2] 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. Based on the definition of scarcity outlined in the Tariff, there were no official scarcity pricing events in 2006, despite record coincident-peak loads recorded across the PJM footprint and within specific zones.

2 114 FERC ¶61,076 (2006).

- **Modifications to Scarcity Pricing.** While PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, an analysis of 2006 market results suggests that PJM's current set of scarcity pricing rules may need refinement. The MMU reviewed the summer of 2006 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 steps or states of scarcity, each with an associated price, rather than the single step now in the Tariff. Scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. In addition, the actual market signal needs further refinement. 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. The single scarcity price signal should be replaced by locational signals.

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 2006.** Operating reserve charges were lower in 2006 by 53 percent. The reasons for the substantial decrease in the balancing operating reserve charges included decreased fuel costs and improved operating practices by PJM.

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 requirements 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.

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 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 are not fully synchronized.

The issue is how to understand this phenomenon and how to address it within the context of competitive markets. The 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.

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. Ideally, a capacity market would include a mechanism for equilibrating energy and capacity market revenues such that, in equilibrium, generators receive a market-based return for investing in capacity from all markets taken together. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The PJM Reliability Pricing Model (RPM) is an 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 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 Balancing Energy Market over the last eight years and the Day-Ahead Energy Market over the last seven years illustrates that additional market modifications are necessary if PJM is to pass that test. A combination of the RPM design and enhancements of scarcity pricing are two such modifications.

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 here because the analysis is based on economic dispatch in the PJM model.[3] Gross energy market revenue is the product of the energy market price and generation output. Gross revenues are also received from the Capacity Market and the 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 including 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 based on the analysis of actual net revenues for actual units operating in PJM. In order to provide a more complete analysis, energy net revenues were developed separately for both the Balancing and the Day-Ahead Energy Market.

3 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. The PJM model also ensures that generators are compensated for startup and no-load costs when they are dispatched based on marginal costs or on their offer price.

Table 3-1 illustrates the relationship between generator variable cost and net revenue from the PJM Balancing Energy Market alone for the years 1999 through 2006.

Table 3-1 PJM balancing energy market net revenue [By unit marginal cost (Dollars per MWh)]: Calendar years 1999 to 2006

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

Table 3-2 illustrates the relationship between generator variable cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2006.[4]

Table 3-2 PJM day-ahead energy market net revenue [By unit marginal cost (Dollars per MWh)]: Calendar years 2000 to 2006

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

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 markets, where equilibrium seldom occurs, net revenue fluctuates annually based on actual conditions in all relevant markets.

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

The net revenue analysis includes energy net revenues for both the Balancing and Day-Ahead Energy Market for a natural gas-fired combustion turbine (CT), a two-on-one, natural gas-fired, combined-cycle (CC) plant and a pulverized coal (CP) steam plant as the new entry technologies in order to provide a relatively complete representation of entry conditions. Two dispatch scenarios are analyzed for each new entry technology and Energy Market.

The net revenue analysis includes nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emission market allowance costs in the dispatch rate, adjustments to plant capacity and energy production based on hourly ambient air and river water temperatures, use of unit class-specific forced outage rates and calculation of ancillary service revenues based on actual PJM unit-class experience.

The net revenue calculations under perfect dispatch are an approximate measure, generally representing an upper bound of the markets' direct contribution to generator fixed costs. The energy market net revenue curve does 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 start-up time for a summer weekday could prevent a unit from running during two profitable hours in the afternoon peak and two more profitable hours in the evening peak separated by two unprofitable hours, or could result in reduced net revenues from the unprofitable hours.[5] The actual impact depends on the relationship between locational marginal price (LMP) and the operating costs of the unit. Likewise, a CP steam plant with an eight-hour cold status notification plus start-up time could run overnight during unprofitable hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[6] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all profitable 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 real-time price, e.g. a forward price.

In order to provide an approximate lower bound to the perfect economic dispatch net revenues, additional dispatch scenarios were analyzed for each plant type.

Energy Market Net Revenue

The balancing 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 2006 for the Balancing Market and 2000 to 2006 for the Day-Ahead Energy Market when the average PJM hourly locational market price exceeded the identified marginal cost of generation. The table includes 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.[7] For example, during 2006, if a unit had

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

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

7 Balancing 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 this table includes a range of marginal costs from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 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.

marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the balancing energy market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2006, adjusted for forced outages, it would have received $171,735 per installed MW-year in net revenue from the Balancing Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $117,447 per installed MW-year in net revenue from the Day-Ahead Energy Market.[8]

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 balancing energy market net revenue curve was lower in 2006 for every level of unit marginal costs compared to 2005 except for when the balancing energy market LMP was $150 per MWh or higher. The 2006 net revenues for units with marginal costs equal to, or less than, $50 were higher than for any year except 2005 since PJM introduced markets in 1999. As Figure 3-2 shows, the day-ahead energy market net revenue curve for 2006 was close to the average level for every year with the exception of 2005, when net revenues for a unit with marginal costs at or below $110 per MWh would have been higher than any other year.

The decrease in 2006 balancing energy market net revenue compared to 2005 is the result of changes in the frequency distribution of energy prices. In 2006, prices were greater than, or equal to, $30 less frequently than in 2005 as the 2006 simple average LMP was $49.27 per MWh and the simple average LMP in 2005 was higher at $58.08 per MWh. In 1999, the balancing 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 and 74 percent in 2006.

The decrease in 2006 as compared to 2005 day-ahead energy market net revenue is also the result of changes in the frequency distribution of energy prices. In 2006, prices were greater than, or equal to, $30 less frequently than in 2005 as the 2006 simple average LMP was $48.10 per MWh and the simple average LMP in 2005 was higher at $57.89 per MWh. 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 and in 2006, 80 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 $85 in 2006. An efficient CC could have produced energy at an average cost of $20 in 1999, but $65 in 2005. An efficient CP could have produced energy at an average cost of $20 in 1999, but $30 in 2006.

The system average hourly balancing energy market LMP exceeded $200 for 35 hours and exceeded $400 for six hours with the maximum balancing energy market LMP at $736.80. The system average hourly day-ahead energy market LMP exceeded $200 for 25 hours and there were no hours when LMP exceeded $400.

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

Figure 3-1 PJM balancing energy market net revenue (By unit marginal cost): Calendar years 1999 to 2006

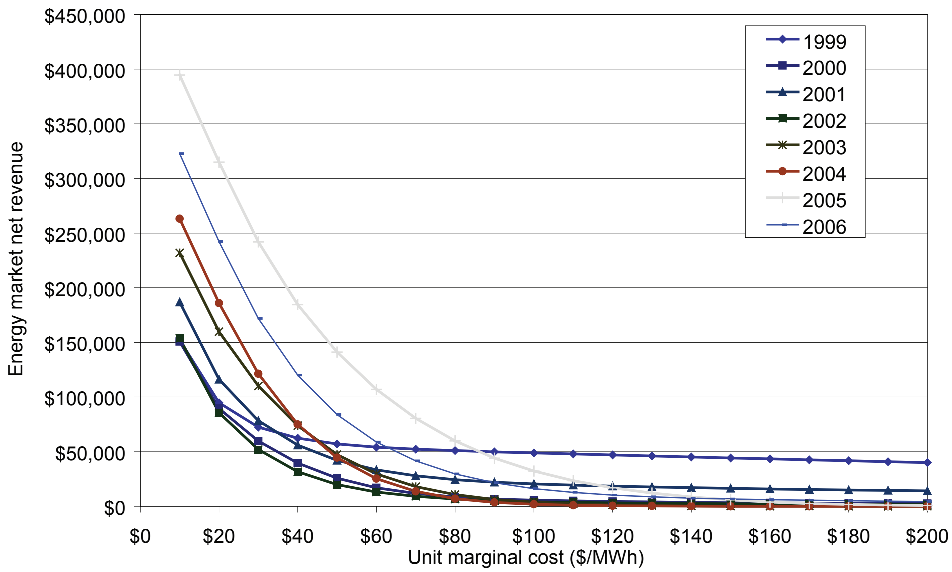
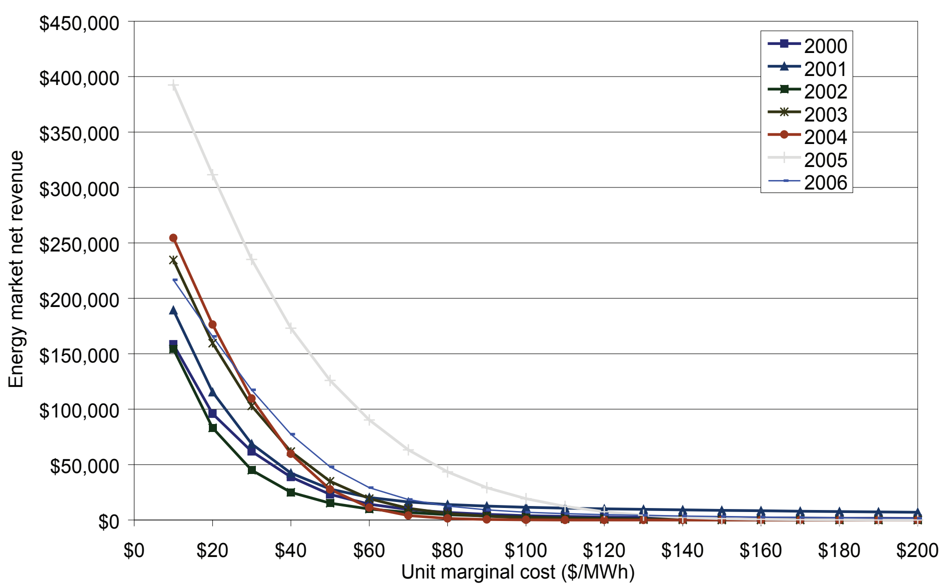


Figure 3-2 PJM day-ahead energy market net revenue (By unit marginal cost): Calendar years 2000 to 2006



Differences in the shape and position of balancing energy market net revenue curves for the eight years result from different distributions of energy market prices. 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.[9] Balancing energy market revenues for 2006 are higher than every year since 1999 for units with a

9 See *2006 State of the Market Report*, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

marginal cost up to and including $60 with the exception of 2005, primarily because the higher fuel costs of gas-fired marginal units resulted in higher prices and thus higher energy revenues for generators with lower fuel cost. The day-ahead energy market net revenue curves show that the curve for 2006 is similar to every prior year with the exception of 2005 when the net revenues were higher for a unit with marginal costs of $110 per MWh or less.

Capacity Credit Market Net Revenue

Generators receive revenues 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. In 2006, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Market (CCM) of $5.73 per MW-day of unforced capacity, or $1,958 per MW-year of installed capacity. This is the lowest level of CCM revenues since the opening of PJM markets in 1999.

The CCM price used for net revenue calculations is the composite CCM, excluding ComEd, through May 31, 2005, and the entire PJM footprint from June 1, 2005, forward. The corresponding annual CCM prices are presented in Table 3-3.

Table 3-3 PJM's average annual CCM price: Calendar years 1999 to 2006

	Dollars per Installed MW-Year
1999	$18,124
2000	$20,804
2001	$32,981
2002	$11,600
2003	$5,946
2004	$6,493
2005	$2,089
2006	$1,958

Ancillary Service and Operating Reserve Net Revenue

Generators also receive revenue from the sale of ancillary services, including those from the Synchronized Reserve and Regulation Markets as well as black start and reactive services. Aggregate ancillary service revenues were $3,926 per installed MW-year in 2006. (See Table 3-4.) 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. Theoretical net revenue calculations, addressed later in this section, use more detailed, technology-specific ancillary service estimates.

Table 3-4 System average ancillary service revenues: Calendar years 1999 to 2006

	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

Although not included in the net revenue analyses, generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Market. Operating reserve payments were about $3,800 per installed MW-year in 2005 and were about $1,600 per installed MW-year in 2006. 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 and that they are not required to run at a loss.

New Entrant Net Revenue Analysis

Analysis of both the balancing 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[10] and river water cooling temperature[11] and the effect of each, as applicable, on plant heat rates[12] and generator output for

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

11 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>.

12 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to PJM, 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.

each of the three plant configurations.[13] 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.[14] 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 sold in the CCM, 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 CCM auctions, by plant type.

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 for the prompt year.[15] 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.[16] 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 $5.00 per MWh for the CT plant, $1.50 per MWh for the CC plant and $2.00 per MWh for the CP plant. These estimates were provided by a consultant to PJM and are based on quoted, third-party contract prices.[17] The VOM expenses for the CT and CC plants include accrual of anticipated routine major overhaul expenses.[18] The burner tip fuel cost for natural gas is from published[19] commodity daily cash prices, with a basis adjustment for transportation costs. Coal burner tip cost was developed from the published prompt-month price,[20] adjusted for rail transportation cost. The average burner tip fuel prices are shown in Table 3-5.

Balancing energy market ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 synchronized reserve, but the 2006 Tier 1 revenues were minimal. Balancing energy market 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. Balancing energy market 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

13 Pasteris Energy, Inc.

14 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.

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

16 Outage figures obtained from the PJM eGADS database.

17 Pasteris Energy, Inc.

18 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.

19 Gas daily cash prices obtained from Platts.

20 Coal prompt prices obtained from Platts.

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. For CTs, the calculated rate is $2,194 per installed MW-year; for CCs, the calculated rate is $3,094 per installed MW-year and for CPs, the calculated rate is $1,692 per installed MW-year.[21]

Table 3-5 Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2006

	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

The balancing energy market perfect dispatch scenario total net revenues for 1999 to 2006 are shown in Table 3-6, Table 3-7 and Table 3-8 for the new entrant CT, CC and CP facilities, respectively.

Table 3-6 PJM balancing energy market new entrant gas-fired CT (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2006

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$62,065	$16,677	$0	$0	$2,248	$80,990
2000	$16,476	$20,200	$0	$0	$2,248	$38,924
2001	$39,269	$30,960	$0	$0	$2,248	$72,477
2002	$23,232	$11,516	$0	$0	$2,248	$36,996
2003	$12,154	$5,554	$0	$0	$2,248	$19,956
2004	$8,063	$5,376	$0	$0	$2,248	$15,687
2005	$15,741	$2,048	$0	$0	$2,248	$20,037
2006	$22,031	$1,758	$0	$0	$2,194	$25,983

21 The CT plant reactive revenues are based on 24 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 19 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on eight recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2005 State of the Market Report* to include new generation filings.

Table 3-7 PJM balancing energy market new entrant gas-fired CC (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2006

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$89,600	$16,999	$0	$0	$3,155	$109,754
2000	$42,647	$19,643	$0	$0	$3,155	$65,445
2001	$68,949	$29,309	$0	$0	$3,155	$101,413
2002	$51,639	$10,492	$0	$0	$3,155	$65,286
2003	$50,346	$5,281	$0	$0	$3,155	$58,782
2004	$49,600	$5,241	$0	$0	$3,155	$57,996
2005	$68,308	$2,054	$0	$0	$3,155	$73,517
2006	$70,828	$1,743	$0	$0	$3,094	$75,665

Table 3-8 PJM balancing energy market new entrant CP (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2006

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$101,011	$17,798	$0	$5,596	$1,692	$126,097
2000	$112,202	$20,755	$0	$3,492	$1,692	$138,141
2001	$106,866	$30,862	$0	$1,356	$1,692	$140,776
2002	$101,345	$11,493	$0	$2,118	$1,692	$116,648
2003	$166,540	$5,688	$0	$2,218	$1,692	$176,138
2004	$136,280	$5,537	$0	$1,399	$1,692	$144,908
2005	$232,351	$2,100	$0	$1,727	$1,692	$237,870
2006	$184,241	$1,810	$0	$1,107	$1,692	$188,850

To demonstrate the sensitivity of the CT balancing energy market net revenue results to the assumption of perfect dispatch with no operating constraints, balancing energy market net revenues were 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 day when the average real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[22] for at least two hours during each four-hour block.[23] 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 calculations account for operating reserve 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 3-6 results.

22 Startup and shutdown fuel burn were obtained from design data for 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.

23 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.

A comparison of the Balancing Energy Market results is shown in Table 3-9, where the first column is the perfect economic dispatch balancing energy market net revenue results from Table 3-6. For the eight-year period, the average balancing energy market net revenue under the perfect economic dispatch scenario was about $24,900 per installed MW-year while the eight-year average for the peak-hour dispatch scenario was about $16,200 per installed MW-year or about a 35 percent reduction in balancing energy market net revenues. Additional, more complex dispatch scenarios were analyzed for the CT plant. The resultant balancing energy market net revenues were about the same as for the peak-hour dispatch scenario.

Table 3-9 Balancing energy market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2006[24]

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
1999	$62,065	$55,612	($6,452)	(10.4%)
2000	$16,476	$8,498	($7,978)	(48.4%)
2001	$39,269	$30,254	($9,015)	(23.0%)
2002	$23,232	$14,496	($8,736)	(37.6%)
2003	$12,154	$2,763	($9,390)	(77.3%)
2004	$8,063	$919	($7,144)	(88.6%)
2005	$15,741	$6,141	($9,600)	(61.0%)
2006	$22,031	$10,996	($11,035)	(50.1%)
Average	$24,879	$16,210	($8,669)	(34.8%)

To demonstrate the sensitivity of the CC balancing energy market net revenue results to the assumption of perfect dispatch with no operating constraints, 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 average PJM real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[25] for at least eight hours during that time period. If there were not eight economic hours in any given day, then the CC was not dispatched. The calculations account for operating reserve 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 3-7 results.

A comparison of the results is shown in Table 3-10 where the first column is the perfect economic dispatch balancing energy market net revenue results from Table 3-7. For the eight-year period, the average balancing energy market net revenue under the perfect economic dispatch scenario was about $61,500 per installed MW-year while the eight-year average for the peak-hour dispatch scenario is about $41,600 per installed MW-year or about a 32 percent reduction in balancing energy market net revenues. Additional, more

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

25 Startup and shutdown fuel burn 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, 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 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.

complex dispatch scenarios were analyzed for the CC plant. The resultant balancing energy market net revenues were about the same as for the peak-hour dispatch scenario.

Table 3-10 Balancing energy market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2006

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
1999	$89,600	$80,546	($9,055)	(10.1%)
2000	$42,647	$24,794	($17,854)	(41.9%)
2001	$68,949	$54,206	($14,743)	(21.4%)
2002	$51,639	$38,625	($13,015)	(25.2%)
2003	$50,346	$27,155	($23,191)	(46.1%)
2004	$49,600	$27,389	($22,211)	(44.8%)
2005	$68,308	$35,608	($32,700)	(47.9%)
2006	$70,828	$44,692	($26,136)	(36.9%)
Average	$61,490	$41,627	($19,863)	(32.3%)

To demonstrate the sensitivity of the CP balancing energy market net revenue results to the assumption of perfect dispatch with no operating constraints, balancing 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 full operating reserve, when applicable, since the assumed operation is under the direction of PJM operations. The additional 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.[26]

26 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.

A comparison of the results is shown in Table 3-11 where the first column is the perfect economic dispatch balancing energy market net revenue results from Table 3-8. For the eight-year period, the average balancing energy market net revenue under the perfect economic dispatch scenario was about $142,600 per installed MW-year while the eight-year average for the available dispatch scenario is about $134,900 per installed MW-year or about a 5 percent reduction in balancing energy market net revenues.

Table 3-11 Balancing energy market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2006

	Perfect Economic Dispatch	All Available Hour Economic	Difference	Percent Difference
1999	$101,011	$92,935	($8,076)	(8.0%)
2000	$112,202	$108,624	($3,578)	(3.2%)
2001	$106,866	$95,361	($11,506)	(10.8%)
2002	$101,345	$96,828	($4,517)	(4.5%)
2003	$166,540	$159,912	($6,628)	(4.0%)
2004	$136,280	$124,497	($11,783)	(8.6%)
2005	$232,351	$222,911	($9,440)	(4.1%)
2006	$184,241	$177,852	($6,389)	(3.5%)
Average	$142,605	$134,865	($7,740)	(5.4%)

In order to develop a comprehensive net revenue analysis, day-ahead energy market net revenues[27, 28] were calculated for the CT, CC and CP class types for both the perfect economic dispatch and peak-hour dispatch scenarios as presented with regard to the balancing energy market analysis. The results for the Day-Ahead Energy Market for each class are listed in Table 3-12, Table 3-13 and Table 3-14, respectively.

Table 3-12 Day-ahead energy market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
2000	$13,419	$7,418	($6,001)	(44.7%)
2001	$25,432	$20,390	($5,042)	(19.8%)
2002	$18,343	$13,921	($4,421)	(24.1%)
2003	$3,884	$1,282	($2,601)	(67.0%)
2004	$520	$1	($519)	(99.8%)
2005	$6,720	$2,996	($3,724)	(55.4%)
2006	$8,608	$5,229	($3,379)	(39.3%)
Average	$10,989	$7,320	($3,670)	(33.4%)

27 The day-ahead energy market net revenues were calculated utilizing the same fuel, weather and unit operational assumptions as were used for the balancing energy market net revenue calculations.

28 The Day-Ahead Energy Market was initialized on June 1, 2000. For the analysis presented in Table 3-12, Table 3-13 and Table 3-14, the balancing energy market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-13 Day-ahead energy market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
2000	$40,374	$26,132	($14,242)	(35.3%)
2001	$58,004	$48,253	($9,751)	(16.8%)
2002	$45,033	$35,993	($9,039)	(20.1%)
2003	$35,825	$21,865	($13,960)	(39.0%)
2004	$31,674	$18,193	($13,482)	(42.6%)
2005	$50,022	$28,413	($21,610)	(43.2%)
2006	$46,636	$31,670	($14,966)	(32.1%)
Average	$43,938	$30,074	($13,864)	(31.6%)

Table 3-14 Day-ahead energy market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Perfect Economic Dispatch	All Available Hour Economic	Difference	Percent Difference
2000	$120,935	$116,784	($4,151)	(3.4%)
2001	$105,076	$95,119	($9,957)	(9.5%)
2002	$100,641	$97,493	($3,148)	(3.1%)
2003	$167,308	$162,285	($5,022)	(3.0%)
2004	$125,416	$113,892	($11,524)	(9.2%)
2005	$226,137	$220,824	($5,314)	(2.3%)
2006	$171,653	$167,282	($4,371)	(2.5%)
Average	$145,309	$139,097	($6,212)	(4.3%)

For the seven-year period, the average day-ahead energy market net revenue under the perfect economic dispatch scenario for the CT plant was about $11,000 per installed MW-year, while the seven-year average for the peak-hour dispatch scenario was about $7,300 per installed MW-year, a 33 percent difference in day-ahead energy market net revenues. For the CC plant, the seven-year average day-ahead energy market net revenue under the perfect dispatch scenario was about $43,900 per installed MW-year while the seven-year average for the peak-hour dispatch scenario was about $30,100 per installed MW-year, a 32 percent difference in day-ahead energy market net revenues. For the CP plant, the seven-year average day-ahead energy market net revenue under the perfect dispatch scenario was about $145,300 per installed MW-year while the seven-year average for the available-hour dispatch scenario was about $139,100 per installed MW-year, a 4 percent difference.

The energy net revenues for both the Balancing and Day-Ahead Energy Market are shown in Table 3-15, Table 3-16 and Table 3-17 for the CT, CC and CP plant, respectively. For the CT plant, the perfect dispatch scenario balancing energy market net revenue averaged about $19,600 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $11,000 per installed MW-year over the same period, a difference of about 44 percent between the two

Energy Markets.[29] For the CT plant in the peak-hour dispatch scenario, the balancing energy market net revenue averaged about $10,600 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $7,300 per installed MW-year over the same period, a difference of about 31 percent between the two Energy Markets.

For the CC plant, the perfect dispatch scenario balancing energy market net revenue averaged about $57,500 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $43,900 per installed MW-year over the same period, a difference of about 24 percent between the two Energy Markets. For the CC plant in the peak-hour dispatch scenario, the balancing energy market net revenue averaged about $36,100 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $30,100 per installed MW-year over the same period, a difference of about 17 percent between the two markets.

For the CP plant, the perfect dispatch scenario balancing energy market net revenue averaged about $148,600 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $145,300 per installed MW-year for the same period, a difference of about 2 percent between the two Energy Markets. For the CP plant in the available-hour dispatch scenario, the balancing energy market net revenue averaged about $140,900 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $139,100 per installed MW-year over the same period, a difference of about 1 percent between the two markets.

Table 3-15 Balancing and day-ahead energy market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Balancing Perfect Economic Dispatch	Day Ahead Perfect Economic Dispatch	Perfect Economic Dispatch Difference	Perfect Economic Dispatch Percent Difference	Balancing Peak Hour Economic	Day Ahead Peak Hour Economic	Peak Hour Economic Dispatch Difference	Peak Hour Economic Dispatch Percent Difference
2000	$16,476	$13,419	($3,058)	(18.6%)	$8,498	$7,418	($1,080)	(12.7%)
2001	$39,269	$25,432	($13,837)	(35.2%)	$30,254	$20,390	($9,864)	(32.6%)
2002	$23,232	$18,343	($4,890)	(21.0%)	$14,496	$13,921	($575)	(4.0%)
2003	$12,154	$3,884	($8,270)	(68.0%)	$2,763	$1,282	($1,481)	(53.6%)
2004	$8,063	$520	($7,543)	(93.6%)	$919	$1	($918)	(99.9%)
2005	$15,741	$6,720	($9,021)	(57.3%)	$6,141	$2,996	($3,145)	(51.2%)
2006	$22,031	$8,608	($13,423)	(60.9%)	$10,996	$5,229	($5,767)	(52.4%)
Average	$19,567	$10,989	($8,577)	(43.8%)	$10,581	$7,320	($3,262)	(30.8%)

29 The Day-Ahead Energy Market was initialized on June 1, 2000. For the analysis presented in Table 3-15, Table 3-16 and Table 3-17, the balancing energy market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-16 Balancing and day-ahead energy market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Balancing Perfect Economic Dispatch	Day Ahead Perfect Economic Dispatch	Perfect Economic Dispatch Difference	Perfect Economic Dispatch Percent Difference	Balancing Peak Hour Economic	Day Ahead Peak Hour Economic	Peak Hour Economic Dispatch Difference	Peak Hour Economic Dispatch Percent Difference
2000	$42,647	$40,374	($2,274)	(5.3%)	$24,794	$26,132	$1,338	5.4%
2001	$68,949	$58,004	($10,945)	(15.9%)	$54,206	$48,253	($5,953)	(11.0%)
2002	$51,639	$45,033	($6,607)	(12.8%)	$38,625	$35,993	($2,631)	(6.8%)
2003	$50,346	$35,825	($14,521)	(28.8%)	$27,155	$21,865	($5,290)	(19.5%)
2004	$49,600	$31,674	($17,925)	(36.1%)	$27,389	$18,193	($9,196)	(33.6%)
2005	$68,308	$50,022	($18,286)	(26.8%)	$35,608	$28,413	($7,196)	(20.2%)
2006	$70,828	$46,636	($24,192)	(34.2%)	$44,692	$31,670	($13,023)	(29.1%)
Average	$57,474	$43,938	($13,536)	(23.6%)	$36,067	$30,074	($5,993)	(16.6%)

Table 3-17 Balancing and day-ahead energy market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Balancing Perfect Economic Dispatch	Day Ahead Perfect Economic Dispatch	Perfect Economic Dispatch Difference	Perfect Economic Dispatch Percent Difference	Balancing Available Hour Economic	Day Ahead Available Hour Economic	Available Hour Economic Dispatch Difference	Available Hour Economic Dispatch Percent Difference
2000	$112,202	$120,935	$8,732	7.8%	$108,624	$116,784	$8,159	7.5%
2001	$106,866	$105,076	($1,791)	(1.7%)	$95,361	$95,119	($242)	(0.3%)
2002	$101,345	$100,641	($704)	(0.7%)	$96,828	$97,493	$665	0.7%
2003	$166,540	$167,308	$768	0.5%	$159,912	$162,285	$2,374	1.5%
2004	$136,280	$125,416	($10,864)	(8.0%)	$124,497	$113,892	($10,605)	(8.5%)
2005	$232,351	$226,137	($6,214)	(2.7%)	$222,911	$220,824	($2,087)	(0.9%)
2006	$184,241	$171,653	($12,588)	(6.8%)	$177,852	$167,282	($10,571)	(5.9%)
Average	$148,547	$145,309	($3,237)	(2.2%)	$140,855	$139,097	($1,758)	(1.2%)

Zonal Net Revenue

In order to show how net revenue varies by location, balancing energy market net revenues were calculated for each of the 17 current PJM transmission zones for the economic dispatch scenarios. The results are presented in Table 3-18, Table 3-19 and Table 3-20 for the CT, CC and CP. Net revenues are shown for a transmission zone only if that zone was integrated into PJM for the entire calendar year. The tables show the balancing energy market net revenue using PJM average prices and the differential net revenues for each zone. For example, in Table 3-18 the 2006 calendar year net revenue for a CT plant using the average PJM LMP is $10,996 per installed MW-year. The net revenue for the same plant located in the ComEd transmission zone is $3,865 per installed MW-year less than the PJM average net revenue or $7,131 per installed MW-year.

Table 3-18 Balancing energy market net revenue differentials by transmission zone for a CT under peak-hour dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$16,210
AECO	$666	$3,579	$10,571	$4,952	$2,511	$5,846	$12,168	$12,169	$6,558
AEP	NA	NA	NA	NA	NA	NA	($5,501)	($6,358)	($5,929)
AP	NA	NA	NA	NA	($1,694)	($55)	($952)	($301)	($751)
BGE	($842)	($1,305)	($7,206)	$5,553	$1,433	$1,980	$16,152	$20,729	$4,562
ComEd	NA	NA	NA	NA	NA	NA	($4,394)	($3,865)	($4,130)
DAY	NA	NA	NA	NA	NA	NA	($5,348)	($6,654)	($6,001)
Dominion	NA	NA	NA	NA	NA	NA	NA	$15,834	$15,834
DPL	$2,013	$4,214	$19,579	$7,933	$2,824	$1,962	$8,117	$6,269	$6,614
DLCO	NA	NA	NA	NA	NA	NA	($5,477)	($5,588)	($5,532)
JCPL	$334	$1,305	$7,219	($563)	$218	$13,553	$10,792	$4,936	$4,724
Met-Ed	($614)	($430)	$443	$2,875	$840	$1,352	$9,032	$6,507	$2,501
PECO	$897	$3,262	$7,735	$265	$2,072	$681	$9,972	$4,604	$3,686
PENELEC	($615)	($1,138)	($12,117)	($2,379)	($1,033)	$345	($3,025)	($4,411)	($3,047)
PEPCO	($1,057)	($1,476)	($12,146)	$7,528	$1,847	$2,996	$19,698	$26,805	$5,524
PPL	($307)	($745)	($3,506)	($1,907)	($498)	$201	$6,262	$2,616	$264
PSEG	$659	$1,673	$6,564	($997)	$1,791	$12,244	$10,740	$4,984	$4,707
RECO	NA	NA	NA	NA	$1,450	$2,830	$6,829	$2,610	$3,430

Table 3-19 Balancing energy market net revenues by transmission zone for a CC under peak-hour dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$41,627
AECO	$384	$4,560	$14,116	$7,578	$8,502	$25,236	$41,615	$33,796	$16,974
AEP	NA	NA	NA	NA	NA	NA	($23,075)	($22,997)	($23,036)
AP	NA	NA	NA	NA	($8,120)	($7,226)	$140	($2,958)	($4,541)
BGE	($1,873)	($3,504)	($11,631)	$6,416	$2,009	$6,150	$40,073	$38,953	$9,574
ComEd	NA	NA	NA	NA	NA	NA	($13,829)	($13,961)	($13,895)
DAY	NA	NA	NA	NA	NA	NA	($23,737)	($24,986)	($24,361)
Dominion	NA	NA	NA	NA	NA	NA	NA	$33,575	$33,575
DPL	$3,203	$9,263	$25,302	$10,539	$6,758	$11,702	$25,558	$16,379	$13,588
DLCO	NA	NA	NA	NA	NA	NA	($24,828)	($25,795)	($25,311)
JCPL	$171	$1,031	$6,969	($1,646)	($200)	$35,811	$31,660	$11,675	$10,684
Met-Ed	($1,018)	($1,799)	($867)	$2,845	$218	$3,890	$21,743	$14,625	$4,955
PECO	$710	$3,216	$7,319	($236)	$4,334	$7,181	$25,604	$12,657	$7,598
PENELEC	($825)	($1,783)	($14,733)	$3,446	($4,226)	($5,929)	($8,998)	($14,220)	($5,909)
PEPCO	($2,203)	($3,929)	($17,254)	$7,729	$2,758	$8,813	$46,819	$46,428	$11,145
PPL	($619)	($2,672)	($6,162)	($4,000)	($1,877)	($2,701)	$16,078	$8,166	$777
PSEG	$2,031	$3,857	$8,262	($856)	$7,394	$36,186	$42,573	$21,754	$15,150
RECO	NA	NA	NA	NA	$6,523	$17,084	$28,462	$16,818	$17,222

Table 3-20 Balancing energy market net revenues by transmission zone for a CP under available-hour dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$134,865
AECO	($403)	$4,813	$13,427	$9,139	$9,060	$43,113	$78,227	$50,812	$26,023
AEP	NA	NA	NA	NA	NA	NA	($79,980)	($55,721)	($67,851)
AP	NA	NA	NA	NA	($19,734)	($10,309)	$2,372	($4,466)	($8,034)
BGE	($2,718)	($8,936)	($13,627)	$6,984	$3,328	$14,301	$74,387	$65,763	$17,435
ComEd	NA	NA	NA	NA	NA	NA	($86,856)	($60,717)	($73,786)
DAY	NA	NA	NA	NA	NA	NA	($90,661)	($63,693)	($77,177)
Dominion	NA	NA	NA	NA	NA	NA	NA	$57,810	$57,810
DPL	$3,237	$16,300	$34,385	$12,672	$9,046	$26,280	$57,944	$30,192	$23,757
DLCO	NA	NA	NA	NA	NA	NA	($103,567)	($74,930)	($89,248)
JCPL	($684)	($2,968)	$4,006	($2,167)	($4,348)	$52,608	$61,516	$20,743	$16,088
Met-Ed	($1,882)	($6,606)	($2,989)	$2,330	($2,781)	$10,564	$46,989	$27,655	$9,160
PECO	($13)	$3,419	$6,197	($715)	$4,029	$19,888	$56,395	$25,300	$14,313
PENELEC	($1,046)	$783	($11,268)	$10,617	($5,617)	($9,954)	($12,675)	($21,129)	($6,286)
PEPCO	($3,061)	($9,274)	($19,896)	$8,297	$5,083	$17,880	$84,956	$77,111	$20,137
PPL	($1,488)	($7,771)	($8,779)	($6,873)	($7,237)	$2,515	$37,656	$18,497	$3,315
PSEG	$2,260	$12,781	$12,797	($388)	$14,249	$56,021	$86,959	$41,915	$28,324
RECO	NA	NA	NA	NA	$16,766	$34,691	$69,538	$35,997	$39,248

Net Revenue Adequacy

To put the net revenue results in perspective, the first operating year's annual fixed costs[30] for the assumed new entrant CT plant configuration would be about $68,700 per installed MW-year[31] or about $80,300 per installed MW-year if levelized over the 20-year life of the project.[32] The first operating year's annual fixed cost for the assumed CC and CP plant configurations would be about $84,800 per installed MW-year and $228,900 per installed MW-year, respectively.[33] The levelized 20-year operating annual costs for the CC and CP plants would be about $99,200 per installed MW-year and $267,800 per installed MW-year, respectively. Table 3-21 shows the first-year fixed costs and 20-year operating life levelized costs for each technology.[34]

30 The annual fixed costs for all three new entry plant configurations were re-evaluated for the *2006 State of the Market Report* and the fixed costs are now higher than previous state of the market reports. The 2006 update has been incorporated into Table 3-21 through Table 3-25.

31 Installed capacity at 92 degrees F.

32 This analysis was performed for PJM by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target equity 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.

33 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2006.

34 The figures in Table 3-21 represent the annual cost for the first year of operation. For example, the $68,657 per installed MW-year figure represents the annual cost of the CT for the first operational year of the plant. Assuming a two-year construction period, the cost for the first year of construction would be $65,349 per installed MW-year.

Table 3-21 New entrant first-year and 20-year levelized fixed costs [By plant type (Dollars per installed MW-year)]

	First-Year Fixed Cost	20-Year Levelized Fixed Cost
CT	$68,657	$80,315
CC	$84,826	$99,230
CP	$228,922	$267,792

In 2006, under the perfect economic dispatch scenario, net revenue from the Balancing Energy Market, the CCM and the Ancillary Service Markets for a new entrant CT were approximately $26,000 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 $7.40 per MBtu and a VOM rate of $5 per MWh.[35] The resulting net revenue stream would not have covered the fixed costs of a new CT if it ran during all profitable hours.

In 2006, under the perfect economic dispatch scenario, net revenue from the Balancing Energy Market, the CCM and the Ancillary Service Markets for a new entrant CC were approximately $75,700 per installed MW-year. The associated operating costs were between $60 and $70 per MWh, based on a design heat rate of 7,150 Btu per kWh, average daily delivered natural gas prices of $7.40 per MBtu and a VOM rate of $1.50 per MWh. The resulting net revenue stream would not have covered the fixed costs of the CC plant if it ran during all profitable hours.

In 2006, under the perfect economic dispatch scenario, net revenue from the Energy Market, the CCM and the Ancillary Service Markets for a new entrant CP would have been approximately $188,900 per installed MW-year. The associated operating costs would have ranged between $30 and $35 per MWh,[36] based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.68 per MBtu and a VOM rate of $2 per MWh. This revenue stream would not have covered the fixed costs of a CP plant if it ran during all profitable hours.

In 1999 and 2001, the net revenue shown for the CT and CC plants was sufficient to cover the first year's fixed costs as shown in Table 3-22 and Table 3-23, respectively. In 2000 and 2002 through 2006, there was, however, a revenue shortfall for both plant types. For the CP, 2005 was the only year with sufficient net revenues to cover the first year's fixed cost as shown in Table 3-24.

Under the perfect economic dispatch scenario, the eight-year net revenue averaged $38,900 per installed MW-year for a new entrant CT plant, $76,000 per installed MW-year for a new entrant CC plant and $158,700 per installed MW-year for a new entrant CP plant. Thus, under perfect economic dispatch over the eight-year period, the average net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

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

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

Table 3-22 CT 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2006

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$80,990	112%	$74,537	103%
2000	$72,207	$38,924	54%	$30,946	43%
2001	$72,207	$72,477	100%	$63,462	88%
2002	$72,207	$36,996	51%	$28,260	39%
2003	$72,207	$19,956	28%	$10,565	15%
2004	$72,207	$15,687	22%	$8,543	12%
2005	$72,207	$20,037	28%	$10,437	14%
2006	$80,315	$25,983	32%	$14,948	19%
Average	$73,221	$38,881	53%	$30,212	42%

Table 3-23 CC 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2006

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$109,754	117%	$100,700	108%
2000	$93,549	$65,445	70%	$47,592	51%
2001	$93,549	$101,413	108%	$86,670	93%
2002	$93,549	$65,286	70%	$52,272	56%
2003	$93,549	$58,782	63%	$35,591	38%
2004	$93,549	$57,996	62%	$35,785	38%
2005	$93,549	$73,517	79%	$40,817	44%
2006	$99,230	$75,665	76%	$49,529	50%
Average	$94,259	$75,982	81%	$56,120	60%

Table 3-24 CP 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2006

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$126,097	61%	$118,021	57%
2000	$208,247	$138,141	66%	$134,563	65%
2001	$208,247	$140,776	68%	$129,271	62%
2002	$208,247	$116,648	56%	$112,131	54%
2003	$208,247	$176,138	85%	$169,510	81%
2004	$208,247	$144,908	70%	$133,125	64%
2005	$208,247	$237,870	114%	$228,430	110%
2006	$267,792	$188,850	71%	$182,461	68%
Average	$215,690	$158,679	74%	$150,939	70%

Table 3-22 through Table 3-24 show net revenues under the perfect dispatch and economic scenarios compared to the 20-year levelized fixed costs of each plant type. During the eight-year period from 1999 to 2006, the CT plant recovered 53 percent of the average 20-year levelized fixed costs under the perfect dispatch scenario and 42 percent under the economic scenario. During that same period the CC plant recovered 81 percent of the average fixed costs under the perfect dispatch scenario and 60 percent under the economic and the CP recovered 74 percent of the average fixed costs under the perfect dispatch scenario and 70 percent under the economic dispatch scenario.

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 2006 net revenue indicates that the fixed costs of new peaking, midmerit and coal-fired baseload were not covered. During the eight-year period 1999 to 2006, the data lead to the conclusion that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower, less volatile Energy Market and lower CCM prices.

Shortfalls in net revenue affect the returns earned by new generating units. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on equity for an investment in a new generating unit. The return on equity was calculated for a range of 20-year levelized net revenue streams, assuming the *2006 State of the Market Report*, 20-year levelized fixed costs from Table 3-21. Levelized net revenues were modified and the return on equity calculated. A $5,000 per MW-year sensitivity was used for the CT and CC and a $10,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-25.[37]

37 This analysis was performed for PJM by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target equity 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.

Table 3-25 Return on equity 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	$85,315	13.8%	$104,230	13.4%	$277,792	13.2%
Base Case	$80,315	12.0%	$99,230	12.0%	$267,792	12.0%
Sensitivity 2	$75,315	10.1%	$94,230	10.6%	$257,792	10.8%
Sensitivity 3	$70,315	8.1%	$89,230	9.2%	$247,792	9.6%
Sensitivity 4	$65,315	5.9%	$84,230	7.6%	$237,792	8.3%
Sensitivity 5	$60,315	3.5%	$79,230	6.1%	$227,792	7.0%
Sensitivity 6	$55,315	0.4%	$74,230	4.4%	$217,792	5.6%

The results show that the return on equity increases and declines with net revenue. These figures represent a 20-year levelized net revenue stream and cannot be used to analyze a single year or several years of operation.

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2006, PJM installed capacity decreased slightly from 163,027 MW on January 1 to 162,143 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, 2006, PJM installed capacity was 163,026.9 MW.[38] (See Table 3-26.) Over the next five months, unit retirements, facility reratings plus import and export shifts changed installed capacity to 163,026.5 MW on May 31, 2006.

38 Percents shown in Table 3-26 and Table 3-27 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-26 PJM capacity (By fuel source): January 1, May 31, June 1 and December 31, 2006

	1-Jan-06		31-May-06		1-Jun-06		31-Dec-06	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,279.2	41.3%	66,691.2	40.9%	66,511.2	40.9%	66,532.5	41.0%
Oil	10,816.4	6.6%	10,823.8	6.6%	10,866.2	6.7%	10,718.1	6.6%
Gas	45,954.3	28.2%	46,962.7	28.8%	47,199.8	29.1%	46,963.0	29.0%
Nuclear	31,229.3	19.2%	30,797.3	18.9%	30,058.3	18.5%	30,044.8	18.5%
Solid Waste	662.9	0.4%	661.9	0.4%	661.9	0.4%	719.6	0.4%
Hydroelectric	7,057.1	4.3%	7,057.1	4.3%	7,128.1	4.4%	7,132.3	4.4%
Wind	27.7	0.0%	32.5	0.0%	32.5	0.0%	32.5	0.0%
Total	163,026.9	100.0%	163,026.5	100.0%	162,458.0	100.0%	162,142.8	100.0%

At the beginning of the new planning year on June 1, 2006, installed capacity decreased by 568.5 MW to 162,458.0 MW, a 0.3 percent decrease in total PJM capacity over the May 31 level.

On December 31, 2006, PJM installed capacity was 162,142.8 MW.[39]

Energy Production by Fuel Source

In calendar year 2006, coal and nuclear units generated 91.4 percent of the total electricity, natural gas 5.5 percent, oil 0.3 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 0.1 percent of total generation. (See Table 3-27.)

Table 3-27 PJM generation [By fuel source (GWh)]: Calendar year 2006

	GWh	Percent
Coal	411,581.2	56.8%
Oil	2,029.9	0.3%
Gas	40,044.5	5.5%
Nuclear	250,995.7	34.6%
Solid Waste	4,801.2	0.7%
Hydroelectric	14,684.7	2.0%
Wind	787.9	0.1%
Total	724,925.1	100.0%

39 Wind-based resources accounted for 32.5 MW of installed capacity in PJM on December 31, 2006. This value represents 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 the most recent three years of 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 2006, about 49,000 MW of capacity were in generation request queues for construction through 2016, compared to an average installed capacity of 162,571 MW in 2006 and a year-end, installed capacity of about 162,143 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity. (See Table 3-28.)

Table 3-28 Year-to-year capacity additions: Calendar years 2000 to 2006

Year	MW
2000	504
2001	1,068
2002	3,800
2003	3,521
2004	1,925
2005	777
2006	137

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 S will be active through July 31, 2007.[40]

Capacity in generation request queues (See Table 3-29.) for the 11-year period beginning in 2006 and ending in 2016 increased by 24,533 MW from 24,428 MW in 2005 to 48,961 MW in 2006.[41, 42] Queued capacity scheduled for service in 2006 decreased from 5,931 MW to 2,689 MW, or 55 percent. Queued capacity scheduled for service in 2007 increased from 5,425 MW to 7,988 MW, or 47 percent. Capacity in the queues for each of the years 2007 through 2010 also increased in 2006 over 2005. Queued capacity scheduled for service in the years 2011 through 2016 indicates that capacity is being planned further in the future than last year. In 2005, no projects were in queues projected to enter service later than 2010.

40 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. Queue commencement and expiration dates have been changed to reflect the correct dates.

41 See the *2005 State of the Market Report* (March 8, 2006), pp. 138-139, for the queues in 2005.

42 The 48,961 MW includes generation with scheduled in-service dates in 2006 and earlier years net of generation that is in service earlier than scheduled.

Table 3-29 Queue comparison (MW): Calendar years 2006 vs. 2005

	MW in the Queue 2005	MW in the Queue 2006	Year-to-Year Change (MW)	Year-to-Year Change
2006	5,931	2,689	(3,242)	(55%)
2007	5,425	7,988	2,563	47%
2008	6,462	9,705	3,243	50%
2009	1,735	4,575	2,840	164%
2010	4,875	7,436	2,561	53%
2011	0	5,935	5,935	NA
2012	0	4,159	4,159	NA
2013	0	1,600	1,600	NA
2014	0	0	0	NA
2015	0	3,234	3,234	NA
2016	0	1,640	1,640	NA
Total	24,428	48,961	24,533	NA

Table 3-30 shows the amount of capacity currently 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.[43]

43 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 3-30 Capacity in PJM queues (MW): At December 31, 2006[44]

Queue	Active	In Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,933	0	18,190	27,123
B Expired 31-Jan-99	0	4,470	0	16,050	20,520
C Expired 31-Jul-99	47	531	0	4,104	4,682
D Expired 31-Jan-00	0	768	0	7,603	8,371
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	1,125	21,293	23,574
H Expired 31-Jan-02	0	260	443	8,422	9,125
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	3,558	4,290
M Expired 31-Jul-04	458	96	373	3,662	4,589
N Expired 31-Jan-05	2,413	1,929	159	5,268	9,769
O Expired 31-Jul-05	4,224	248	79	3,339	7,890
P Expired 31-Jan-06	6,417	393	15	2,122	8,947
Q Expired 31-Jul-06	14,224	0	5	1,312	15,541
R Expired 31-Jan-07	14,309	0	0	0	14,309
Total	42,853	19,268	3,519	123,291	188,931

Data presented in Table 3-30 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.[45]

44 The *2005 State of the Market Report* included only new capacity in the queues. The *2006 State of the Market Report* contains all projects in the queue including reratings of existing generating units and energy only resources.

45 The data for Queue R include projects through December 31, 2006.

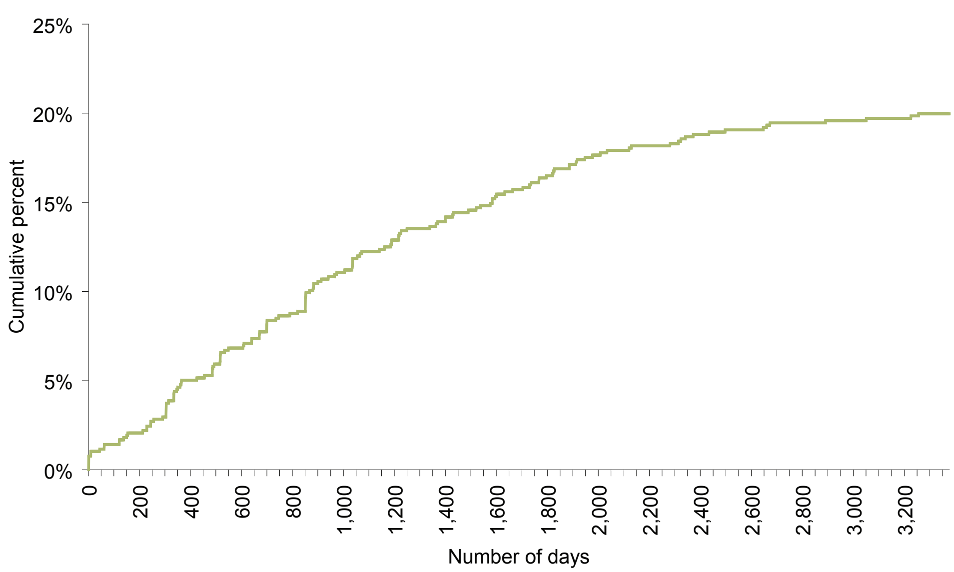
The data presented in Table 3-31 show that for successful projects there is an average time of 1,050 days (2.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 933 days (2.6 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

Table 3-31 Average project queue time: At December 31, 2006

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In Service	1,050	784	0	3,376
Under Construction	1,124	463	333	2,159
Withdrawn	933	735	0	3,376
Active	475	364	152	2,890

Figure 3-3 shows the cumulative probability of completion of RTEP projects. The first queue (Queue A) was opened more than 3,600 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 3-3. The data show that about 15 percent of all projects in the queue are completed within 1,584 days and approximately 20 percent of the projects are completed within 3,376 days.

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



Distribution of Units in the Queues

Table 3-32 shows the RTEP projects under construction or active as of December 31, 2006, by unit type and control zone. Most (92 percent of the MW) of the steam projects (predominantly coal) and most of the wind projects (89 percent of the MW) are outside the Eastern MAAC[46] and Southwestern MAAC[47] locational deliverability areas (LDAs).[48] Most (60 percent of the MW) of the combined-cycle (CC) projects are in the Eastern MAAC and Southwestern MAAC LDAs. Wind projects account for approximately 15,607 MW of capacity or 34 percent of the capacity in the queues and combined-cycle projects account for 7,306 MW of capacity or 16 percent of the capacity in the queues.[49] Of the total capacity additions only about 6,500 MW or 14 percent are projected to be in the zones that are in the Eastern MAAC LDA and about 4,600 MW or 10 percent are projected to be constructed in the zones that are in the Southwestern MAAC LDA.

Table 3-32 Capacity additions in active or under-construction queues by zone (MW): At December 31, 2006

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	225	0	4	0	0	650	0	879
AEP	0	27	247	5	84	5,349	1,078	6,790
AP	640	0	11	0	0	2,547	2,078	5,276
BGE	0	10	5	0	3,280	0	0	3,295
ComEd	600	0	104	0	280	765	6,948	8,697
DAY	0	24	0	0	0	0	444	468
Dominion	1,633	0	97	94	1,594	62	0	3,480
DPL	0	0	14	0	0	630	1,749	2,393
JCPL	1,261	20	40	1	0	0	0	1,322
Met-Ed	47	0	37	0	0	0	0	84
PECO	550	20	7	0	140	0	0	717
PENELEC	0	0	0	16	0	310	2,281	2,607
PEPCO	1,250	14	0	0	0	0	0	1,264
PPL	0	0	15	140	218	6,202	1,029	7,604
PSEG	1,100	46	7	0	43	0	0	1,196
UGI	0	0	0	0	0	300	0	300
Total	7,306	161	588	256	5,639	16,815	15,607	46,372

46 The Eastern MAAC LDA consists of the AECO, DPL, PECO, JCPL and PSEG Control Zones.

47 The Southwestern MAAC LDA consists of the BGE and PEPCO Control Zones.

48 See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a PJM LDA map.

49 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 15,600 MW of wind resources means that only 33,900 MW of capacity are effectively in the queue of the 46,400 MW currently active in the queues.

Table 3-33 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 now in the queue (See Table 3-32.) and the location of units likely to retire. In both the Eastern and Southwestern MAAC LDAs, the capacity mix is likely to shift to more natural gas-fired CC and combustion turbine (CT) capacity. In other LDAs, continued reliance on steam (mainly coal) seems likely.

Table 3-33 Existing PJM capacity 2006 [By zone and unit type (MW)]

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	15	0	0	1,108	8	1,814
AEP	4,133	3,473	0	1,008	2,093	22,735	0	33,442
AP	1,129	1,085	43	80	0	7,862	81	10,280
BGE	0	872	0	0	1,735	2,793	0	5,400
ComEd	1,790	6,232	15	0	11,448	7,194	103	26,782
DAY	0	1,316	54	0	0	3,851	0	5,221
DLCO	272	45	0	0	1,630	1,164	0	3,111
Dominion	2,515	3,226	105	3,321	3,459	8,271	0	20,897
DPL	1,088	764	82	0	0	1,825	0	3,759
External	72	1,223	0	0	0	8,615	0	9,910
JCPL	1,635	1,217	0	400	619	9	0	3,880
Met-Ed	2,043	416	1	17	786	804	0	4,067
PECO	2,407	1,498	8	1,618	4,492	2,022	0	12,045
PENELEC	0	336	44	490	0	6,775	42	7,687
PEPCO	1,134	1,333	0	0	0	4,781	0	7,248
PPL	1,674	613	35	568	2,289	5,832	114	11,125
PSEG	2,581	3,016	15	11	3,353	2,538	0	11,514
Total	22,628	27,193	417	7,513	31,904	88,179	348	178,182

Table 3-34 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 91 percent of all MW 40 years of age and older and nearly 99 percent of such MW if hydroelectric is excluded from the total. Approximately 6,619 MW of steam units 40 years of age and older are located the Eastern MAAC and Southwestern MAAC LDAs.

Table 3-34 PJM capacity age (MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Less than 10	17,414	17,094	95	119	0	755	348	35,825
10 to 20	4,610	2,950	67	54	6,532	8,532	0	22,745
20 to 30	134	33	52	3,112	13,951	10,616	0	27,898
30 to 40	470	6,959	164	1,505	11,421	39,974	0	60,493
40 to 50	0	157	34	1,415	0	18,065	0	19,671
50 to 60	0	0	4	354	0	10,101	0	10,459
60 to 70	0	0	1	122	0	136	0	259
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	132	0	0	0	132
100 and over	0	0	0	27	0	0	0	27
Total	22,628	27,193	417	7,513	31,904	88,179	348	178,182

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 Eastern and Southwestern MAAC LDAs are replaced by units burning natural gas. Table 3-35 shows that in the Eastern MAAC LDA, gas consuming unit types (CC and CT facilities) dominate the capacity additions; however, steam and wind projects are new entrants into the queues this year. Steam additions (coal) account for about 20 percent of the MW and wind projects account for 27 percent of the MW in the queue for the Eastern MAAC LDA. Note that the wind capacity in Table 3-35 is reported at nameplate capacity and not reduced by 80 percent. If it were not for newly queued nuclear capacity in the Southwestern MAAC LDA, gas consuming unit types would also dominate the capacity additions in that LDA.

Table 3-35 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2006

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Eastern MAAC	3,136	86	72	1	183	1,280	1,749	6,507
Non-MAAC	2,873	51	459	99	1,958	8,723	10,548	24,711
Southwestern MAAC	1,250	24	5	0	3,280	0	0	4,559
Western MAAC	47	0	52	156	218	6,812	3,310	10,595
PJM Total	7,306	161	588	256	5,639	16,815	15,607	46,372

Table 3-36 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. Nearly 51 percent of the Eastern MAAC LDA generation would be from CC and CT generators, an increase of 5.5 percentage points from today. 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 the Eastern MAAC LDA from about 37 percent to about 41 percent. This proportion of gas-fired capacity in the Eastern MAAC LDA would increase to 44 percent if the 80 percent reduction for wind capacity is taken into account for the Eastern MAAC LDA, meaning that the effective capacity additions are 5,108 MW.

The exact expected role of gas-fired generation depends heavily on the projects currently in the queues. Two coal projects in the Eastern MAAC LDA totaling 1,280 MW face substantial site-related issues. There is a planned addition of 3,300 MW of nuclear capacity in the Southwestern MAAC LDA.

Without the planned coal-fired capability in the Eastern MAAC LDA, new gas-fired capability would represent 62 percent of all new capability in the Eastern MAAC LDA and 84 percent when the 80 percent reduction for wind capability is included. In 2016 this would mean that combined-cycle and combustion turbine generators would comprise 54.7 percent of total generation in the Eastern MAAC LDA.

Without the planned nuclear capability in the Southwestern MAAC LDA, new gas-fired capability would represent 99.6 percent of all new capability in the Southwestern MAAC LDA. In 2016 this would mean that combined-cycle and combustion turbine generators would comprise 41.3 percent on of total generation in the Southwestern MAAC LDA.

Table 3-36 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2010[50]

Area	UnitType	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators All Ages	Percent of Area Total	Additional Capability through 2016	Estimated Capacity 2016	Percent of Area Total
Eastern MAAC	Combined Cycle	0	0.0%	7,866	23.8%	3,136	11,002	31.0%
	Combustion Turbine	157	3.1%	7,023	21.3%	86	6,952	19.6%
	Diesel	30	0.6%	120	0.4%	72	162	0.5%
	Hydroelectric	948	19.0%	2,029	6.1%	1	2,030	5.7%
	Nuclear	0	0.0%	8,464	25.6%	183	8,647	24.4%
	Steam	3,855	77.3%	7,502	22.7%	1,280	4,927	13.9%
	Wind	0	0.0%	8	0.0%	1,749	1,757	5.0%
	Eastern MAAC Total	4,990	100.0%	33,012	100.0%	6,507	35,477	100.0%
Non-MAAC	Combined Cycle	0	0.0%	9,911	9.0%	2,873	12,784	11.1%
	Combustion Turbine	0	0.0%	16,600	15.1%	51	16,651	14.4%
	Diesel	3	0.0%	217	0.2%	459	673	0.6%
	Hydroelectric	1,338	6.6%	4,409	4.0%	99	4,508	3.9%
	Nuclear	0	0.0%	18,630	17.0%	1,958	20,588	17.9%
	Steam	19,053	93.4%	59,692	54.4%	8,723	49,362	42.8%
	Wind	0	0.0%	184	0.2%	10,548	10,732	9.3%
	Non-MAAC Total	20,394	100.0%	109,643	100.0%	24,711	115,298	100.0%
Southwestern MAAC	Combined Cycle	0	0.0%	1,134	9.0%	1,250	2,384	16.5%
	Combustion Turbine	0	0.0%	2,205	17.4%	24	2,229	15.4%
	Diesel	0	0.0%	0	0.0%	5	5	0.0%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,735	13.7%	3,280	5,015	34.7%
	Steam	2,764	100.0%	7,574	59.9%	0	4,810	33.3%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	Southwestern MAAC Total	2,764	100.0%	12,648	100.0%	4,559	14,443	100.0%
Western MAAC	Combined Cycle	0	0.0%	3,717	16.2%	47	3,764	12.2%
	Combustion Turbine	0	0.0%	1,365	6.0%	0	1,365	4.4%
	Diesel	6	0.2%	80	0.3%	52	126	0.4%
	Hydroelectric	437	14.2%	1,075	4.7%	156	1,231	4.0%
	Nuclear	0	0.0%	3,075	13.4%	218	3,293	10.7%
	Steam	2,630	85.6%	13,411	58.6%	6,812	17,593	57.0%
	Wind	0	0.0%	156	0.7%	3,310	3,466	11.2%
	Western MAAC Total	3,073	100.0%	22,879	100.0%	10,595	30,838	100.0%
All Areas	Total	31,221		178,182		46,372	196,056	

50 Percents shown in Table 3-36 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2006 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.[51] 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.[52]

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.[53] 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.

While PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, the MMU's review of 2006 market results leads to the recommendation that PJM's scarcity pricing mechanism be reviewed and modified.

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 and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, 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.[54] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days are likely to be the result of appropriate scarcity pricing rather than market power. Under the current PJM rules, administrative scarcity pricing, based on the scarcity pricing provisions in the Tariff, results when PJM takes identified emergency actions and is based on the highest offer of an operating unit.

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

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

52 114 FERC ¶ 61,076 (2006).

53 114 FERC ¶ 61,076 (2006).

54 See *2006 State of the Market Report,* Volume II, Section 2, "Energy Market, Part I," at Figure 2-1 "Average PJM aggregate supply curves: Summers 2005 and 2006."

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.

The challenge is to translate these basic guidelines about scarcity into a consistent set of market rules. The MMU analysis of scarcity constitutes the first step toward a comprehensive analysis of scarcity. The MMU recommendations regarding scarcity pricing represent a step towards a set of market rules but work remains to be done.

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.[55, 56]

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 in the absence 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 but for non market administrative actions. The more emergency resources needed to maintain system reliability, the more severe the scarcity event.

Within-hour, economic (non-emergency) resources include loaded generation, the lesser of the hourly available ramp or remaining non-emergency capacity of synchronized resources, the lesser of hourly available ramp or available non-emergency capacity of non-synchronized resources with less than a one-hour start-up time.[57] All within-hour, available generation values reflect available outage information.

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.[58] The definitions of high-load and scarcity events do not account for potential violations of aggregate or zone-specific, 10-minute primary reserve requirements or 30-minute operating reserve targets. Nonetheless, the net within-hour resource calculation provides a reasonable measure of overall system high-load conditions. The basis of the zone-specific reserve requirements is shown in Table 3-37.

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

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

57 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 (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.

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

Table 3-37 Zone-specific operating reserve targets and requirements[59]

Control Zone	Region	Operating (Day Ahead)	Primary (Real Time)	Synchronized Reserve	Regulation
PJM	Mid-Atlantic	Load Dependent	1,700 MW	Largest Unit	1% Peak
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

Non market administrative tools available to PJM to ensure the convergence of supply and demand include active load management (ALM), capacity recalls of noncapacity-backed exports, load reduction action (Emergency Load-Response Program), the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dump.[60] Of these steps, the last four (the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dump) are defined in the PJM Tariff as triggers for scarcity pricing events.[61]

Any non market administrative tools used 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. For example, PJM-called ALM, which reduces load, would be added to total demand for determination of within-hour net resources. PJM-called ALM in 2006 is shown in Table 3-38. In the event that maximum emergency generation was loaded at PJM direction, the value of the hourly maximum emergency generation loaded would be subtracted from PJM total within-hour, non-emergency supply for the determination of net within-hour, available non-emergency resources. When a maximum emergency alert is declared and the maximum emergency capacity is counted towards operating reserve targets, the added capacity is considered to be non-economic for purposes of this analysis. Maximum emergency generation alerts were declared in one or more zones on July 17, through July 18, July 31, and August 1, through August 3, 2006. On those same dates, available maximum emergency capacity was counted towards operating reserve targets.

Table 3-38 PJM-called ALM: August 2 and August 3, 2006

	02-Aug-06		03-Aug-06	
	Start	Stop	Start	Stop
Short lead time ALM called (Mid-Atlantic)	15:30	19:30	13:00	19:00
Long lead time ALM called (Mid-Atlantic)	13:00	19:00	12:15	19:00

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

60 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."

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

2006 Results: High Load and Scarcity Hours

As defined above, there were 70 hours of high load that occurred. Of those 70 hours, 17 high-load hours occurred from July 17 through July 19; 51 high-load hours occurred from July 31 through August 3 and two high-load hours occurred on August 7.[62] Within these 70 hours, there were 10 hours on August 1 and August 2 that met the criteria for potential within-hour scarcity, as defined above.[63]

Figure 3-4 shows the hourly loads of each of the eight high-load days relative to the average hourly summer load for 2006. August 2 had the highest coincident-peak load of the summer, followed closely by August 1.

Figure 3-4 High-load day hourly load and average hourly load: Summer 2006

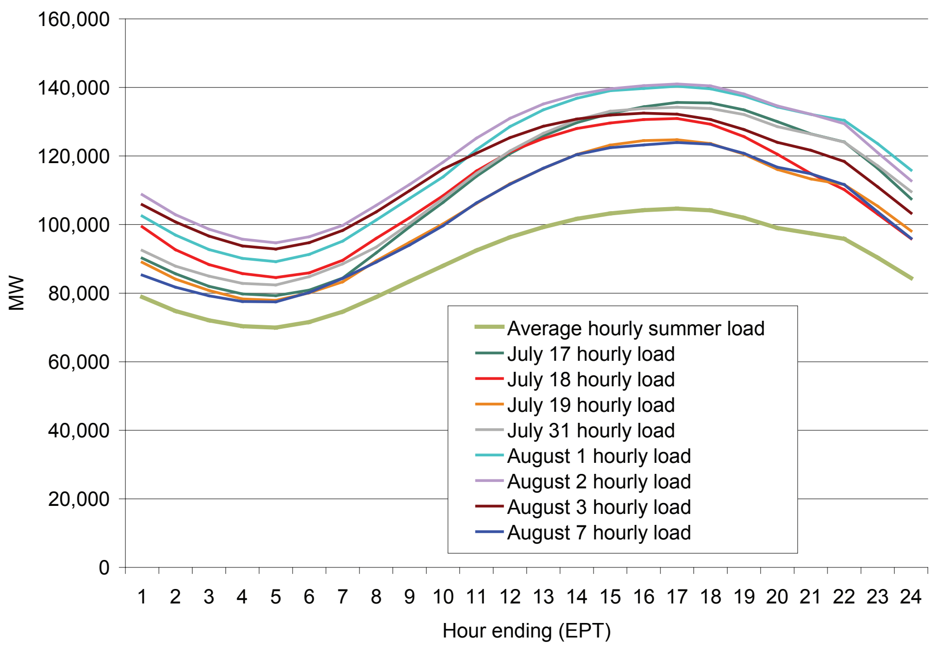


Figure 3-5 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand including the day-ahead operating reserve target for July 17 through July 19, and July 31, 2006.[64, 65] Figure 3-6 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand including the day-ahead operating reserve requirement for August 1 through August 3, and August 7, 2006. In both 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.

62 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 the RTO or transmission zone, requires the use of 90 percent or more of total within-hour, available non-emergency resources in one or more hours in a given 24-hour period.

63 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.

64 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.

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

PJM took emergency action or made use of emergency resources on the days identified as including high load and scarcity hours. PJM operations declared maximum emergency generation alerts for July 17 through July 18, and July 31, through August 3, 2006, for one or more zones. During this period available maximum emergency capacity was included in the calculation of operating reserve by PJM. 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 in each of the days listed. PJM operations recorded primary reserve warnings in one or more zones on July 18, August 2, and August 3, 2006.

Figure 3-5 Net within-hour resources: July 17 to July 19, and July 31, 2006

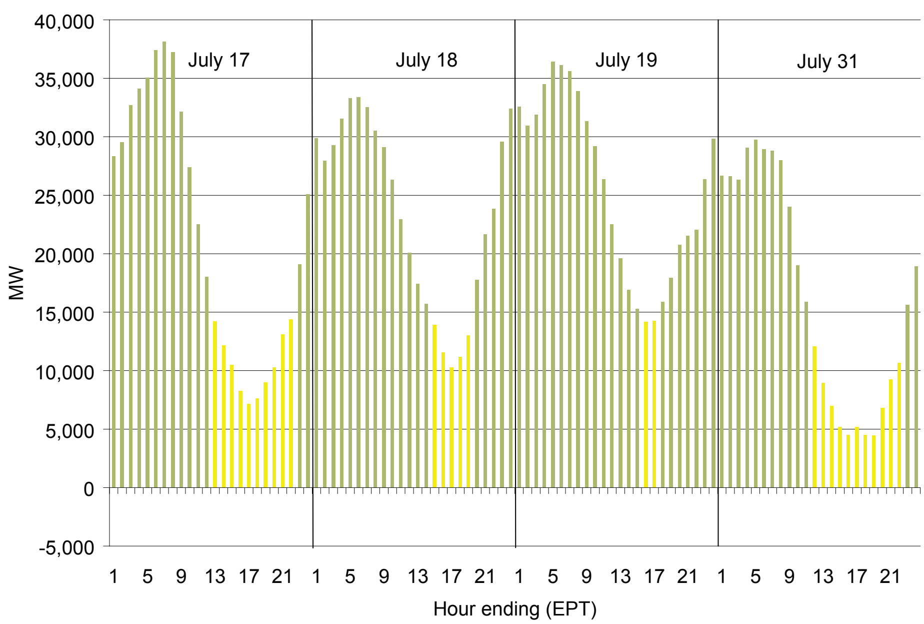


Figure 3-6 Net within-hour resources: August 1 to August 3, and August 7, 2006

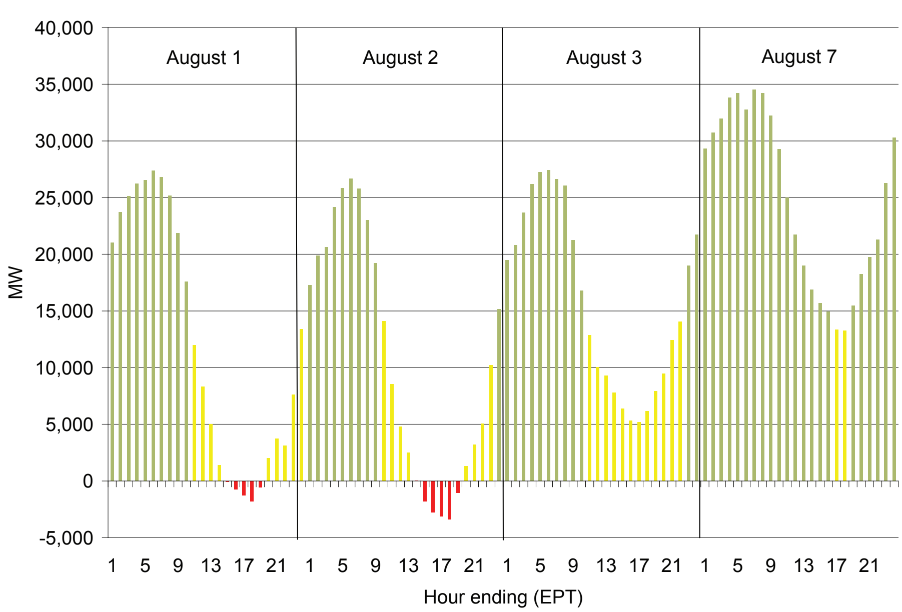
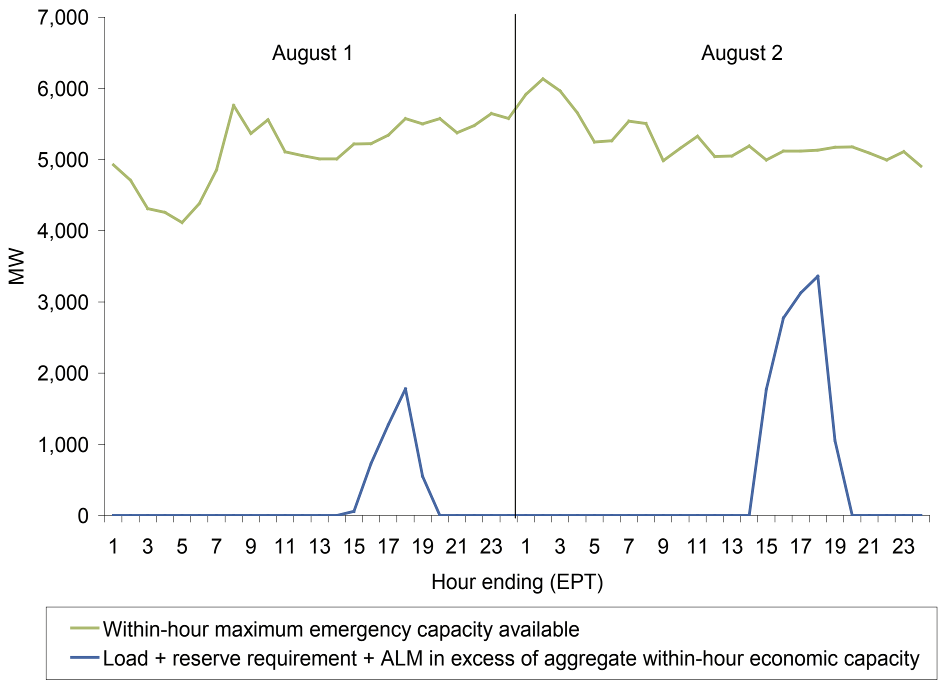


Figure 3-7 shows the within-hour, available maximum emergency generation capacity, by hour and total hourly demand in excess of total within-hour economic supply for August 1 and August 2. On August 1 and August 2, on an hourly aggregate basis, total demand, including the day-ahead operating reserve target and ALM taken, caused PJM to be in a scarcity condition, as defined here.

Figure 3-7 Within-hour maximum emergency capacity relative to hourly demand in excess of within-hour economic resources: August 1 to August 2, 2006



Maximum emergency generation is generation capacity that PJM considers to be above the maximum economic level.[66] In concept, maximum emergency generation should represent 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 shall not qualify as an event beyond the control of the unit owner.

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

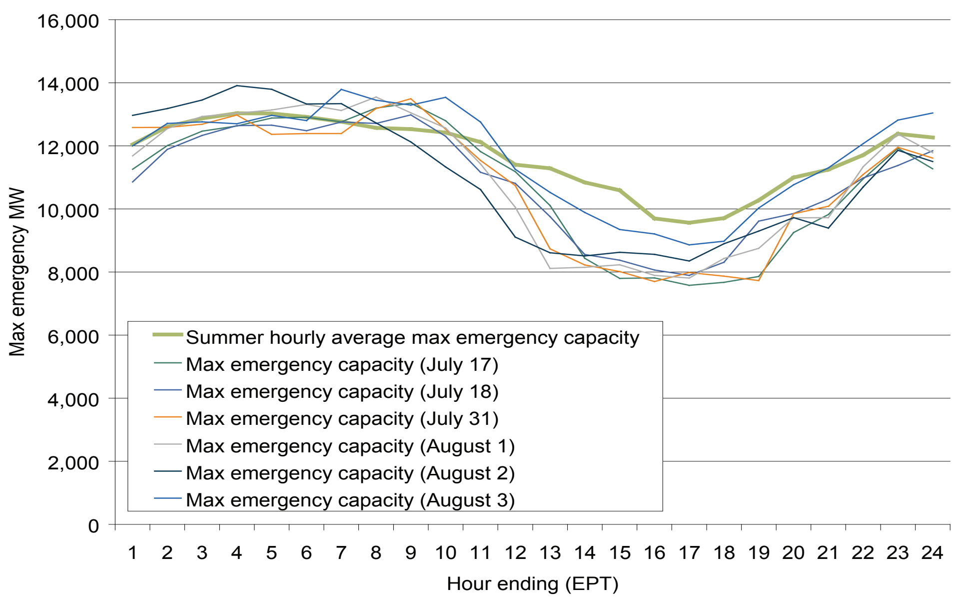
- **Temporary Emergency Conditions at the Unit.** If temporary emergency physical conditions at the unit significantly limit its availability.

- **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.[67]

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.[68]

Figure 3-8 shows the hourly comparison of declared maximum emergency capacity on days when maximum emergency generation alerts had been issued by the RTO 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 3-8 Comparison of hourly maximum emergency capacity on maximum generation alert days to the hourly summer average maximum emergency capacity: Summer 2006



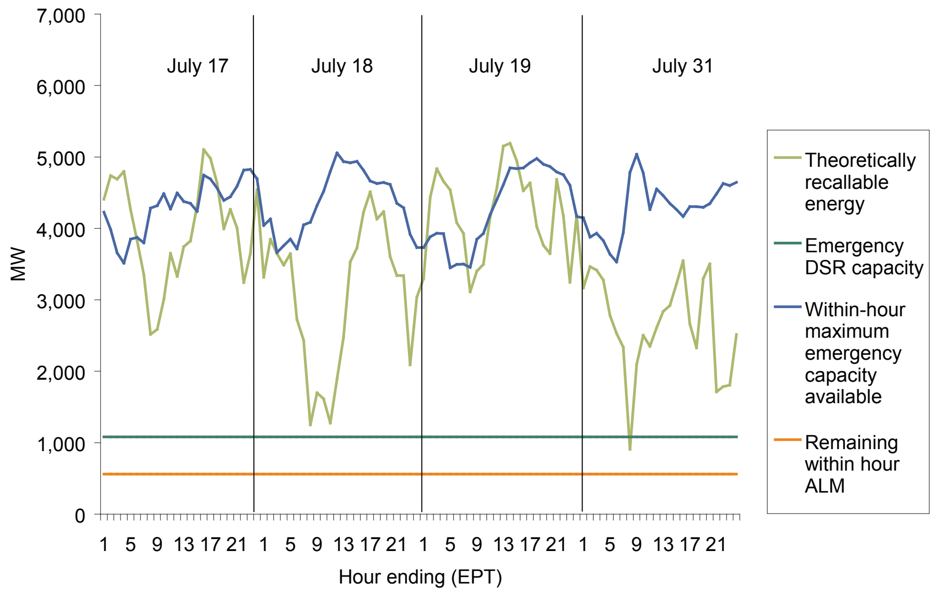
With the exception of potential emergency energy purchases and voltage reduction effects, Figure 3-9 shows each hour's within-hour available emergency resources for July 17 through July 19 and July 31.

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

68 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."

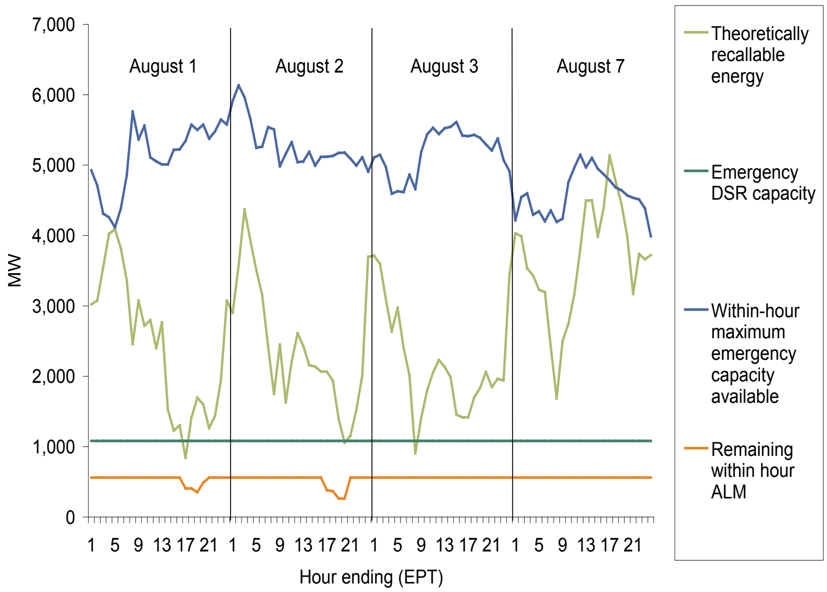
Figure 3-10 shows each hour's within-hour available emergency resources for August 1, through August 3, and August 7, 2006. The figures provide estimates of hourly recallable energy, registered emergency DSR, within-hour available maximum emergency capacity and net remaining short-notification ALM. Maximum emergency capacity available includes the lesser of the hourly available ramp or remaining emergency capacity on synchronized resources and the lesser of hourly available ramp or available capacity of non-synchronized, maximum emergency-only resources with less than a one-hour start-up time.[69] 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 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 neighboring RTOs and control areas which could make the system harder, not easier, to manage, 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 non-economic capacity was available within-hour maximum emergency generation.

Figure 3-9 Within hour emergency resources: July 17 to July 19, and July 31, 2006



69 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 (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 3-10 Within-hour emergency resources: August 1 to August 3, and August 7, 2006



2006 Scarcity Pricing Events

Four emergency messages trigger administrative scarcity pricing under the PJM Tariff. (See Table 3-39.)[70, 71]

Based on these triggers for scarcity pricing, there were no scarcity pricing events in 2006, despite record loads recorded across the PJM footprint and within specific zones.

Table 3-39 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: Electric Distribution Companies

70 "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.

71 114 FERC ¶ 61,076 (2006).

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 2006 market results, that PJM's current set of scarcity pricing rules need refinement.

Although there were identified hours during which supply was less than, or equal to, demand including a day-ahead target level of operating reserve, PJM did not use the specific emergency measures which would have triggered administrative scarcity pricing. PJM was able, via the discretion it is afforded under PJM's Tariff and operating manuals, to use emergency resources to meet operational goals, most notably declaring a maximum emergency alert, which results in the inclusion of maximum emergency generation resources in operational reserve and the calling of ALM resources.

Thus, despite the fact that the demand for power in PJM was very close to the generating capability of the system, prices remained relatively low. This suggests that the definition of scarcity should include several steps or stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff.

In addition, the actual administrative market signal needs further refinement. Under the current rules, a scarcity pricing event will set 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.

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 price levels should be predetermined and applied administratively. The trigger for each stage would be the progressive use of stronger emergency measures. 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 towards operating reserve requirements, the calling of ALM, the recall of noncapacity-backed exports, the use of load reduction action (Emergency DSR), 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. Adders to all unit offers within the affected zones could allow LMP to continue to provide locational economic signals consistent with least-cost dispatch.

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.[72] 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 charges declined substantially in 2006 compared to 2005, in significant part as a result of PJM actions to focus attention on PJM decisions that affected the level of operating reserve charges. In particular, PJM created 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.[73]

The PJM Reserve Market Working Group developed a series of potential steps designed to enhance the efficiency of the operating reserve process and may take action in 2007. 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.

72 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.

73 See Robert O. Hinkel, general manager, PJM Regional Operations, "180 Day Stakeholder Group Operations Process Improvements" (October 24, 2006).

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 3-40 shows the categories of credits and charges and their relationship.

Table 3-40 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	
Balancing Congestion		from Day-Ahead Schedules:	
Lost Opportunity Cost			
Real-Time Import Transactions			
		Net Deviations	
	Day-Ahead		Real-Time
	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 3-42 shows monthly day-ahead operating reserve charges for calendar years 2005 and 2006.

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.

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 3-42 shows monthly synchronous condensing charges for calendar years 2005 and 2006.

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.[74] 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 3-42 shows monthly balancing operating reserve charges for calendar years 2005 and 2006. 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 (1) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled

74 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)[75] and (2) the sum of real-time load, plus real-time sales scheduled through eSchedules[76] plus real-time exports scheduled through the EES.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: (1) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and (2) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports schedule through EES.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between (1) a unit's cleared, day-ahead generation and (2) 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 3-41 shows total operating reserve credits from 1999 through 2006, a period when significant market changes occurred.[77, 78] Total operating reserve credits declined by 52.8 percent in 2006.

Table 3-41 also shows the ratio of total operating reserve credits to the total value of PJM market billings.[79] This ratio decreased from 3.0 percent in 2005 to 1.5 percent in 2006. Over the last eight years, this ratio ranged from a low of 1.5 percent in 2006 to a high of 9.6 percent in 2000.

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

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

77 Table 3-41 includes all categories of credits as defined in Table 3-40 and includes all PJM settlements' billing adjustments. Only the energy market credits were reported in the *2005 State of the Market Report.*

78 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.

79 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-2, "Total annual PJM congestion [Dollars (millions)]: Calendar years 2002 to 2006," for a description of the value of total annual PJM market billings during the period indicated.

Table 3-41[80] Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2006

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as Percent of Total Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	$0.341	NA	$0.535	NA
2001	$290,867,269	34.0%	8.7%	$0.275	(19.5%)	$1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	$0.164	(40.4%)	$0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	$0.226	38.2%	$1.197	52.0%
2004	$414,891,790	43.3%	4.8%	$0.230	1.7%	$1.236	3.3%
2005	$682,781,889	64.6%	3.0%	$0.076	(66.9%)	$2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	$0.078	2.6%	$1.331	(51.7%)

Finally, Table 3-41 shows the total operating reserve credits per MWh for each full year since the introduction of the Day-Ahead Energy Market.[81] The day-ahead operating reserve rate increased $0.002 per MWh or 2.6 percent from $0.076 per MWh in 2005 to $0.078 per MWh in 2006. The balancing operating reserve rate decreased $1.427 per MWh, or 51.7 percent, from $2.758 per MWh in 2005 to $1.331 per MWh in 2006.

80 Calculated values shown in Table 3-41, Table 3-44, Table 3-45, Table 3-46 and Table 3-47 are based on unrounded underlying data and may differ from calculations based on the rounded values in the tables.

81 In Table 3-41, “Total day-ahead and balancing operating reserve charges” numbers are based on PJM market settlements’ data that include manual adjustments. The data in Table 3-42, Table 3-44, Table 3-48 and Figure 3-12 are based on the PJM market settlements’ database and do not include manual adjustments.

Table 3-42 compares monthly operating reserve charges by category for calendar years 2005 and 2006. While total operating reserve charges decreased, the level of day-ahead operating reserve charges increased by 6.51 percent between 2005 and 2006 and their share of total operating reserve charges increased from 8.98 percent to 20.31 percent. Synchronous condensing operating reserve charges decreased by 43.24 percent between 2005 and 2006. Balancing operating reserve charges decreased by 59.39 percent between 2005 and 2006 and their share of total operating reserve charges decreased from 87.42 percent to 75.36 percent.

Table 3-42 Monthly operating reserve charges: Calendar years 2005 and 2006

	2005			2006		
	Day Ahead	Synchronous Condensing	Balancing	Day Ahead	Synchronous Condensing	Balancing
Jan	$9,567,053	$4,424,843	$37,895,417	$7,145,655	$511,823	$16,216,936
Feb	$3,358,460	$1,720,120	$18,965,471	$4,525,771	$241,598	$14,107,994
Mar	$3,116,002	$1,289,212	$15,360,115	$4,924,985	$346,133	$7,992,131
Apr	$2,847,685	$1,097,556	$12,110,506	$5,368,796	$156,352	$7,575,039
May	$7,582,892	$242,506	$14,646,225	$6,129,196	$492,418	$11,837,289
Jun	$3,043,378	$2,379,770	$58,066,579	$4,383,153	$983,353	$18,003,134
Jul	$2,672,044	$2,680,880	$99,637,963	$4,838,992	$2,073,350	$43,756,738
Aug	$2,202,173	$3,609,806	$81,020,542	$5,045,827	$2,364,265	$49,491,691
Sep	$3,035,763	$2,530,569	$76,143,552	$6,765,877	$938,744	$14,273,544
Oct	$5,339,286	$2,141,759	$96,352,636	$5,244,729	$1,654,702	$12,890,522
Nov	$5,493,441	$979,360	$32,242,377	$4,191,905	$882,426	$16,465,964
Dec	$11,356,498	$751,026	$37,809,385	$4,929,665	$2,890,772	$23,017,897
Total	$59,614,675	$23,847,407	$580,250,768	$63,494,551	$13,535,936	$235,628,879
Share of Annual Charges	8.98%	3.59%	87.42%	20.31%	4.33%	75.36%

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 3-43 shows monthly real-time deviations for demand, supply and generator categories for 2005 and 2006. From 2005 to 2006, the share of total deviations in the demand category increased by 4.5 percentage points, in the supply category fell by 5.6 percentage points and in the generator category increased by 1.2 percentage points.

Total deviations in 2006 were less than total 2005 levels for all months except November.

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar years 2005 and 2006

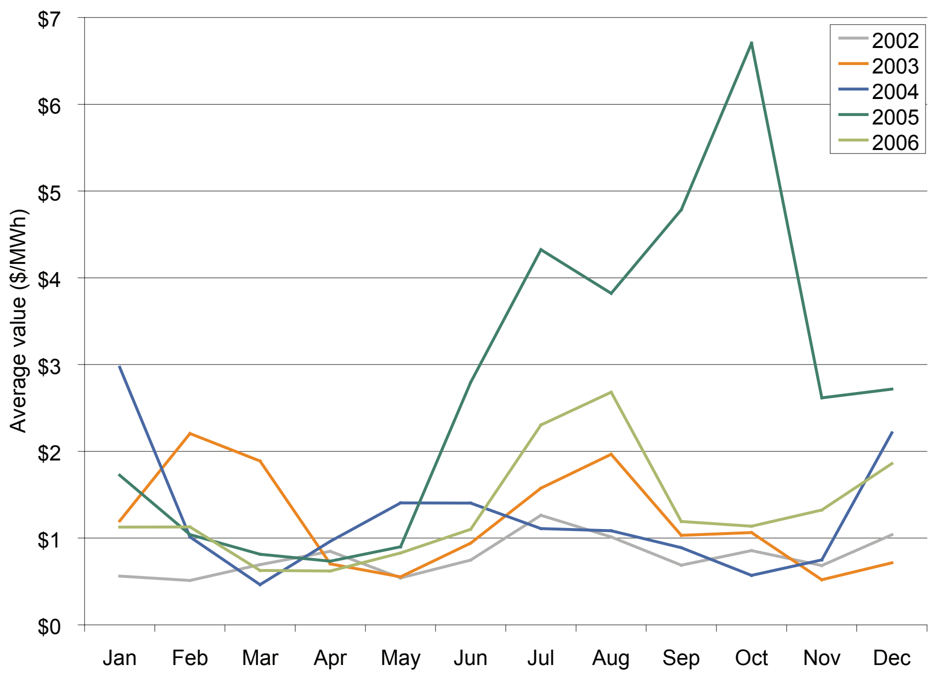
	2005			2006		
	Demand	Supply	Generator	Demand	Supply	Generator
Jan	11,851,254	6,717,597	3,144,258	8,079,917	3,042,526	3,104,765
Feb	9,505,119	5,366,922	3,241,208	7,407,652	2,376,136	2,785,690
Mar	10,367,348	5,198,926	3,637,017	7,782,094	2,440,601	2,579,638
Apr	8,522,724	4,867,238	3,120,261	7,380,697	2,092,666	2,676,689
May	9,280,079	3,893,888	3,395,250	7,732,120	2,476,951	2,700,348
Jun	11,394,615	4,863,249	4,121,267	9,292,155	2,621,207	3,260,040
Jul	13,110,625	5,485,019	4,191,367	11,166,560	3,799,713	3,241,283
Aug	12,021,176	4,702,635	3,783,214	10,639,107	3,321,580	2,879,367
Sep	9,155,776	3,770,614	3,187,321	7,589,892	2,180,845	2,212,283
Oct	7,745,326	3,216,032	2,776,153	6,525,296	2,653,620	2,035,454
Nov	6,971,279	2,822,426	2,343,019	7,228,329	2,685,786	2,379,014
Dec	7,951,859	2,897,055	2,627,646	6,964,809	2,550,484	2,403,937
Total	117,877,180	53,801,601	39,567,981	97,788,628	32,242,115	32,258,508
Share of Annual Deviations	55.80%	25.47%	18.73%	60.26%	19.87%	19.88%

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 3-11 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 2006, the monthly average balancing operating reserve rate decreased to an average of $1.33 per MW, which was lower than 2005 but higher than any prior year.

The reasons for the observed decrease in the balancing operating reserve charges included decreased fuel costs and improved operating practices by PJM.

Figure 3-11 Monthly average balancing operating reserve rate: Calendar years 2002 to 2006



Characteristics of Credits and Charges

Types of Units

Table 3-44 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.[82] In 2006, CT units received 57.58 percent of balancing operating reserve credits although they represented 20.59 percent of the capacity that received such credits and CTs that received balancing operating reserve credits represented 16.19 percent of total, PJM installed capacity. Steam units received 18.98 percent of balancing operating

82 In Table 3-44 balancing operating reserve credits include balancing congestion, balancing energy and lost opportunity cost credits.

reserve credits, but represented 60.50 percent of the capacity that received such credits and steam units that received balancing operating reserve credits represented 47.57 percent of total, PJM 2006 installed capacity. In 2006, units that received balancing operating reserve credits represented 78.62 percent of total installed PJM capacity.[83] In 2005, units that received balancing operating reserve credits represented 84.28 percent of total installed PJM capacity.[84]

Table 3-44 Installed capacity percentage (By unit type): Calendar years 2005 and 2006

	2005			2006		
	Share of Total PJM Capacity	Share of Capacity Receiving Operating Reserve Credits	Share of Balancing Operating Reserve Credits	Share of Total PJM Capacity	Share of Capacity Receiving Operating Reserve Credits	Share of Balancing Operating Reserve Credits
CC	12.42%	14.74%	24.20%	12.49%	15.89%	21.91%
CT	16.96%	20.12%	51.04%	16.19%	20.59%	57.58%
Diesel	0.15%	0.18%	0.53%	0.20%	0.26%	1.50%
Hydroelectric	NA	NA	NA	0.01%	0.01%	0.00%
Nuclear	4.87%	5.78%	0.27%	2.16%	2.75%	0.03%
Steam	49.88%	59.18%	23.97%	47.57%	60.50%	18.98%
Total	84.28%	100.00%	100.00%	78.62%	100.00%	100.00%

Economic and Non-Economic Generation

Economic generation includes units producing energy at an offer price less than, or equal, to LMP. Non-economic generation includes units that are producing energy but at a higher offer price than the LMP. Non-economic 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 non-economic 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 non-economic for an hour may receive adequate market revenues during other hours to offset any shortfall.[85]

83 The value of total PJM installed capacity used for these calculations was based on the amount recorded on December 31, 2006.

84 The results for 2005 in Table 3-44 differ from those reported in the *2005 State of the Market Report*, Section 3, "Energy Market, Part 2," Table 3-29 "Installed capacity percentage (By unit type):Calendar year 2005." The results in the *2006 State of the Market Report* are correct.

85 Self-scheduled units were not included in either economic or non-economic 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 non-economic.

Table 3-45 shows the percentage of total PJM self-scheduled generation, economic generation, non-economic generation and regulation generation for 2006.

Table 3-45 PJM self-scheduled, economic, non-economic and regulation generation: Calendar year 2006

	All Hours	On Peak	Off Peak
Self-Scheduled Generation	48.55%	47.40%	51.27%
Economic Generation	44.50%	48.38%	35.31%
Non-Economic Generation	5.41%	3.57%	9.79%
Regulation Generation	1.54%	0.66%	3.63%
Total	100.00%	100.00%	100.00%

Table 3-46 presents the share of self-scheduled, economic, non-economic and regulation generation for each unit type. For example, in 2006 steam units represented 93.90 percent of all economic generation. Table 3-47 presents the share of each unit type for self-scheduled, economic, non-economic and regulation generation. For example, in 2006 45.06 percent of steam unit generation was economic.

Table 3-46 PJM generation by unit type: Calendar year 2006

	Self-Scheduled Generation	Economic Generation	Non-Economic Generation	Regulation Generation
CC	2.57%	4.42%	17.31%	8.69%
CT	0.31%	0.63%	5.64%	0.85%
Diesel	0.14%	0.01%	0.06%	0.00%
Hydroelectric	3.22%	1.04%	0.00%	0.00%
Steam	93.53%	93.90%	76.99%	90.45%
Wind	0.22%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%

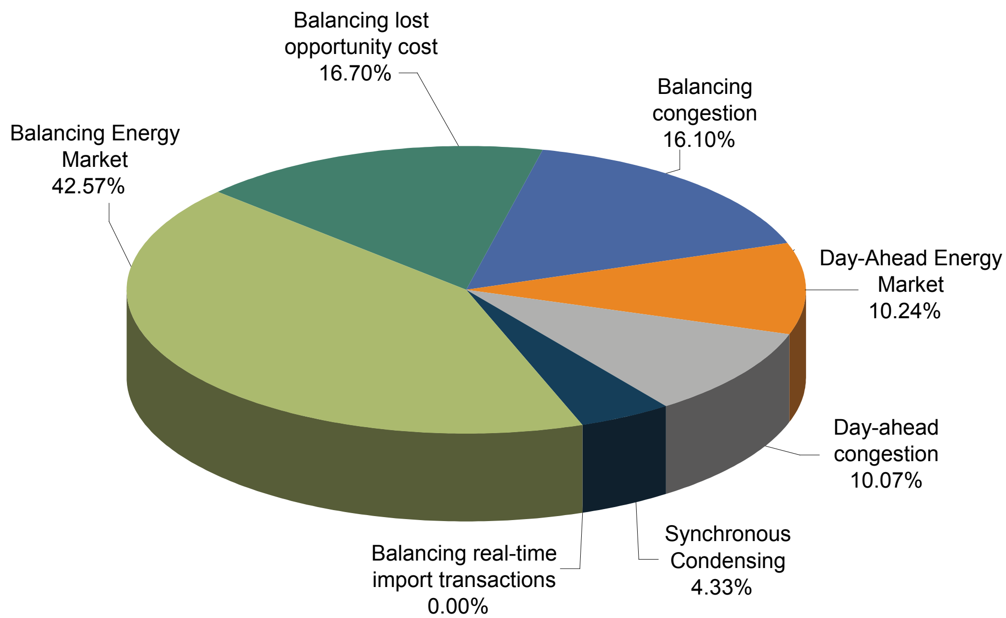
Table 3-47 PJM unit type generation distribution: Calendar year 2006

	Self-Scheduled Generation	Economic Generation	Non-Economic Generation	Regulation Generation	Total
CC	29.14%	45.91%	21.83%	3.12%	100.00%
CT	20.12%	37.57%	40.56%	1.75%	100.00%
Diesel	91.78%	3.74%	4.47%	0.00%	100.00%
Hydroelectric	77.23%	22.77%	0.00%	0.00%	100.00%
Steam	48.95%	45.06%	4.49%	1.50%	100.00%
Wind	100.00%	0.00%	0.00%	0.00%	100.00%

Operating Reserve Credits by Category

Figure 3-12 shows that the largest share of total operating reserve credits, 42.57 percent, was paid to resources in the Balancing Energy Market during 2006 and that 75.36 percent of total operating reserve credits were in the balancing category. Figure 3-12 also shows that 10.24 percent of total operating reserve credits were paid to resources in the Day-Ahead Energy Market and that 20.31 percent of total operating reserve credits were in the day-ahead category.[86]

Figure 3-12 Operating reserve credits: Calendar year 2006



Geography of Balancing Credits and Charges

Table 3-48 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.[87] The other control zones include those in the Western Region (the AEP, AP, ComEd, DAY and DLCO Control Zones) and in the Southern Region (the Dominion Control Zone). On average, 42.78 percent of all generator charges were paid by generators in the Mid-Atlantic Region. On average, 66.11 percent of energy credits, 84.90 percent of congestion credits and 32.39 percent of lost opportunity cost credits were paid to generators in the Mid-Atlantic Region. Table 3-48 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 27.14 percent of all operating reserve charges and generator credits were 71.36 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.

86 The day-ahead import transactions are too small to be shown in Figure 3-12.

87 Balancing operating reserve charges in Table 3-48 include only those in the generator category. Balancing operating reserve credits in Table 3-48 include balancing energy market credits, balancing congestion credits and lost opportunity cost credits. Categories are defined in Table 3-40.

Table 3-48 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2006

	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 Total Operating Reserve Charges	Generation Credits Share Total Operating Reserve Credits
Jan	42.30%	68.54%	87.89%	44.43%	57.70%	31.46%	12.11%	55.57%	30.04%	67.93%
Feb	36.03%	75.67%	76.03%	38.66%	63.97%	24.33%	23.97%	61.34%	32.74%	74.74%
Mar	38.34%	68.07%	83.14%	49.15%	61.66%	31.93%	16.86%	50.85%	24.78%	60.26%
Apr	39.82%	53.85%	63.76%	13.11%	60.18%	46.15%	36.24%	86.89%	25.53%	57.82%
May	42.32%	63.97%	81.20%	9.20%	57.68%	36.03%	18.80%	90.80%	26.81%	64.13%
Jun	42.78%	73.82%	91.32%	14.77%	57.22%	26.18%	8.68%	85.23%	31.50%	77.02%
Jul	48.04%	75.73%	95.65%	26.03%	51.96%	24.27%	4.35%	73.97%	29.16%	86.36%
Aug	44.78%	72.63%	89.48%	24.17%	55.22%	27.37%	10.52%	75.83%	30.35%	86.98%
Sep	45.81%	78.41%	99.90%	32.28%	54.19%	21.59%	0.10%	67.72%	22.50%	64.94%
Oct	44.10%	56.68%	90.95%	58.24%	55.90%	43.32%	9.05%	41.76%	23.03%	65.13%
Nov	42.89%	38.45%	96.73%	47.34%	57.11%	61.55%	3.27%	52.66%	27.50%	76.43%
Dec	46.15%	67.47%	62.77%	31.33%	53.85%	32.53%	37.23%	68.67%	21.77%	74.64%
Average	42.78%	66.11%	84.90%	32.39%	57.22%	33.89%	15.10%	67.61%	27.14%	71.36%

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.

The actions of PJM operators are also part of any analysis of market power affecting the level of operating reserve credits. It is the decisions of PJM operators, constrained by their available tools, by the requirement to maintain system reliability and by the available generating resources, that effectively put units in a position to exercise market power with respect to the payment 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.

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 2006 despite the overall reduction in operating reserve charges. As Table 3-49 shows, the top 10 units, less than 1 percent of all units, received 29.7 percent of total operating reserve credits in 2006, an increase over the 27.7 percent in 2005. The top 20 units received 36.9 percent of operating reserve credits in 2006 and 37.2 percent in 2005. In 2005 the top 10 units were owned by four companies and in 2006 the top 10 were owned by five companies. In 2006, two of the top 10 units changed. One of the new units was owned by the same owner as a unit that dropped from the top 10 and one of the new units was owned by a new owner. In 2005 the top generator received 15 percent of the total operating reserve credits paid, and in 2006 the top generator received 16 percent of the total operating reserve credits.

Table 3-49 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2006

	Percent	Top 10 Units Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%

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.[88] As Table 3-50 shows, the markup for the top 10 units averaged 21 percent in 2006, a substantial increase over prior years with the exception of 2005 when the markup for the top 10 units averaged 75 percent. The markup for the top 10 units is a weighted-average, where the weights are generator output when operating reserve credits are paid. The decreased markup in 2006 over 2005 resulted from a single top 10 unit having had a substantial, unit-specific markup in 2005.

The generation owner with the largest share of top 10 credits received 69 percent of energy market operating reserve credits paid to the top 10 units and had a weighted-average markup of 0 percent in 2006. The next generation owner received 16 percent of energy market operating reserve payments made to the top 10 units and had a weighted-average markup of 79 percent and the third generation owner received 8 percent of energy market operating reserve payments made to the top 10 units and had a weighted-average

88 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].

markup of 18 percent in 2006. In 2005 the top owner received 55 percent of energy market operating reserve payments made to the top 10 units and had a weighted-average markup of 235 percent.

For each year 2001 to 2006, the top 10 units receiving operating reserve credits were either CC technology or conventional steam generation. Steam units accounted for a smaller share of the operating reserve credits received by the top 10 units in 2006, representing 10 percent of the credits received by the top 10 in 2006. CC units accounted for a larger share of the operating reserve credits received by the top 10 units in 2006, representing 90 percent of the credits received by the top 10 in 2006, as shown in Table 3-50.

Table 3-50 Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2006

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	CC Percent of Top 10	CC Markup
2001	3%	60%	2%	40%	7%
2002	11%	54%	8%	46%	20%
2003	17%	50%	19%	50%	11%
2004	3%	12%	0%	88%	5%
2005	75%	20%	53%	80%	82%
2006	21%	10%	2%	90%	24%

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.[89] Table 3-51 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 was paid.[90] For all units, when operating reserve credits were paid, the markup for exempt units was 350 percent larger than the markup for non-exempt units, 27 percent for exempt units and 6 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 130 percent.

89 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Exempt Unit Markup."

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

Table 3-51 Simple average generator markup: Calendar year 2006

Unit Class	Exempt	Non-Exempt	All Units
All Units	27%	6%	8%
CC	24%	4%	6%
CT	26%	10%	11%
Diesel	69%	8%	14%
Steam	NA	0%	0%

Impact of Markup by Exempt Units

Table 3-52 compares the total balancing operating reserve rate and the balancing operating reserve rate adjusted to remove all markups above 10 percent for exempt units. 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 42 exempt units that received balancing operating reserve credits in 2006.[91] 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 2006 would have been lower by about $26 million and the balancing operating reserve rate in 2006 would have been 11 percent lower.

Table 3-52 Balancing operating reserve rate for exempt units (Actual and markup-adjusted): Calendar year 2006

	Current Rate	Markup-Adjusted Rate
Jan	1.13	1.05
Feb	1.13	1.02
Mar	0.63	0.60
Apr	0.62	0.61
May	0.83	0.79
Jun	1.10	1.00
Jul	2.30	2.12
Aug	2.68	2.23
Sep	1.19	0.82
Oct	1.14	1.04
Nov	1.32	1.26
Dec	1.86	1.70
Annual Average	1.33	1.19

91 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.