SECTION 3 - ENERGY MARKET, PART 2

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

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue quantifies the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

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

  In 2009, net revenues were not adequate to cover total fixed costs for a new entrant CT, CC or CP in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues. Energy net revenues are generally lower for each technology in most zones compared to 2008, while capacity market revenues are higher in every zone compared to 2008. For the combustion turbine (CT) and combined cycle (CC) technologies, the increase in capacity revenue offset the reduction in energy market revenue, while that was not the case for the coal plant (CP) which is more dependent on energy market net revenues to cover total fixed costs.

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For the new entrant CT, nine zones had higher net revenue and eight zones had lower net revenue compared to 2008. (Table 3-10.) All zones but one had lower energy net revenue and higher capacity revenue compared to 2008 for the new entrant CT, and, for zones that cleared in the RTO Locational Delivery Area (LDA) for the 2007/2008 and the 2008/2009 BRA, this decrease in energy net revenue was more than offset by higher capacity revenues in the 2009/2010 delivery year. For the new entrant CC, twelve zones had lower net revenue and five zones had higher net revenue compared to 2008, which reflects a decrease in energy market revenue and an increase in capacity revenue in all zones. In AEP, AP, ComEd, DAY, DLCO and PENELEC, the increase in capacity revenues more than offset lower energy net revenues. For the new entrant coal plant (CP), all zones show a significant decrease in net revenue compared to 2008, which is driven by lower energy revenues.

- **Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement. When other factors are considered, including additional fixed and variable costs associated with complying with environmental mandates, this is a key first measure.

  For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue.

  There is a set of sub-critical coal units in 2008 and 2009 and a set of supercritical coal units in 2009 that did not recover avoidable costs even with capacity revenues. The total installed capacity associated with coal units that did not cover avoidable costs in 2009 was 11,250 MW. There were 122 coal units in PJM in 2009 with capacity less than or equal to 200 MW. Of those units, 35 did not cover avoidable costs and 52 were close to not covering avoidable costs.

  The coal plant technologies have higher avoidable costs and are more dependent on net revenues received in the energy market. In 2009, with lower load levels and, generally, lower price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues. If this result is expected to continue, the retirement of these plants would be an economically rational decision.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2009, PJM installed capacity resources rose slightly from 164,898.9 MW on January 1 to 167,326.4 MW on December 31, an increase of 2,427.5 MW or 1.5 percent.

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- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2009, 40.7 percent was coal; 29.2 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During 2009, coal provided 50.5 percent, nuclear 36.0 percent, gas 9.7 percent, oil 0.2 percent, hydroelectric 2.0 percent, solid waste 0.8 percent and wind 0.8 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in 2009.** PJM did not declare a scarcity event in 2009.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using 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. As demand increases and units with higher offers are required to meet demand, prices increase.

- **Scarcity.** A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Thus, the energy market alone frequently does not directly compensate some of the resources needed to provide for reliability.

  The Reliability Pricing Model (RPM) capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, energy market design should 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 part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design, as long as the market rules are designed to ensure that energy market scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

- **Modifications to Scarcity Pricing.** PJM's scarcity pricing rules need refinement.

  The essential components of a new approach to scarcity pricing include: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; and maintaining local market power mitigation mechanisms.

  There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. Given the significant nature of the changes to the PJM markets that is required in order to implement any significant change to scarcity pricing, a step by step approach is warranted. If scarcity pricing is implemented successfully and the markets gain experience with it, higher offer caps should be considered. However, the assertion that much higher prices are required now in order to incent the participation of additional resources is unsupported, particularly given the absence of metering adequate to facilitate a response by the demand side of the market. In addition, the PJM RPM market is designed to achieve the target reliability levels with the resources acquired through the capacity market.

Credits and Charges for Operating Reserve

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

- **Operating Reserve Charges in 2009.** The level of operating reserve credits and corresponding charges decreased in 2009 by 24.1 percent compared to 2008. This decrease was comprised of a 35.5 percent decrease, or $125,479,054, in the amount of balancing operating reserve credits, and an increase of 36.4 percent, or $25,317,144, in day-ahead credits.

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

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The rule changes allocated an increased proportion of balancing operating reserve credits to real-time load and exports. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, determined to be real-time load and exports. The new operating reserve rules resulted in an increase of $30,625,896 in charges assigned to real-time load and exports for 2009. These increases were matched by a decrease of $16,390,083 in charges to demand deviations, a decrease of $9,761,656 in charges to supply deviations, and a decrease of $4,474,157 in charges to generator deviations.

The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $10,441,564 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports.

The rule changes included the introduction of segmented make whole payments, which results in a calculation of operating reserve credits for periods shorter than the 24 hours used under the old rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $7,489,486, or 4.13 percent, higher for the calendar year 2009.

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

Conclusion

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

1 126 FERC ¶ 61,251 (2009).

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 with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity revenues in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

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

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

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

In 2009, energy market revenues were lower as a result of lower energy prices in all zones compared to the same period in 2008. The change in energy market net revenue is a function of the change in locational price levels and fuel costs. In 2009, energy market prices decreased more significantly than fuel prices, and, as a result, energy market net revenues are lower compared to 2008 for all technologies in nearly all locations.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2009. Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes

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from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, or, when energy net revenues available for new entrants decreases rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

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

While the net revenue results demonstrate the role of the capacity market in ensuring appropriate incentives for generating units, the net revenue results also demonstrate that there is a set of units, relatively small subcritical coal units, that is at risk. PJM should ensure that it carefully considers the implications of the potential loss of these units and whether market design changes are required to address that potential loss.

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

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

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

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

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

for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

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

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2009 for the Real-Time Energy Market and during 2000 to 2009 for the Day-Ahead Energy Market when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[4] For example, during 2009, if a unit had marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2009, adjusted for forced outages, it would have received $73,039 per installed MW-year in net revenue from the Real-Time Energy Market alone. The same unit would have received $70,736 per installed MW-year in net revenue from the Day-Ahead Energy Market.[5]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2009.

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

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

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Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2009

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984	$459,738	$220,494
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397	$379,750	$141,212
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215	$302,122	$73,039
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918	$233,568	$38,171
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033	$179,669	$21,792
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768	$138,282	$13,197
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644	$106,343	$8,353
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859	$81,666	$5,366
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467	$62,360	$3,479
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110	$47,397	$2,349
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898	$35,713	$1,588
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655	$26,971	$1,067
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795	$20,281	$731
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737	$15,222	$484
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302	$11,288	$323
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202	$8,351	$205
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357	$6,196	$119
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722	$4,630	$69
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219	$3,464	$41
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831	$2,643	$15

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2009.[6]

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

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Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2009

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734	$456,557	$218,865
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295	$375,221	$138,961
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702	$295,084	$70,736
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320	$221,678	$29,918
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297	$161,374	$13,695
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674	$115,287	$6,695
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135	$80,996	$3,134
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326	$56,349	$1,433
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257	$39,159	$599
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530	$27,761	$189
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730	$20,157	$38
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081	$14,650	$4
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167	$10,633	$0
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703	$7,706	$0
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421	$5,594	$0
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241	$4,034	$0
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118	$2,929	$0
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51	$2,173	$0
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11	$1,611	$0
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0	$1,209	$0

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve was lower in 2009 than in 2008 and in 2007 for every level of unit marginal costs. For units with marginal costs equal to or less than $90, net revenues were lower in 2009 than in any other year since 2003. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve was lower in 2009 than in 2008 and in 2007 for every marginal cost level. For units with marginal costs equal to, or less than, $80, net revenues were lower in 2009 than in any other year since 2003.

The decrease in 2009 Real-Time Energy Market net revenue compared to 2008 is the result of changes in the frequency distribution of energy prices. In 2009, prices were greater than or equal to $30 per MWh less frequently than in 2008. The 2009 simple average LMP was $37.08 per MWh, a substantial decrease compared to $66.40 per MWh in 2008. In 1999, the Real-Time Energy Market LMP was greater than, or equal to, $30 per MWh during 17 percent of all hours. In 2000, this was 29 percent; in 2001, 34 percent; in 2002, 30 percent; in 2003, 51 percent; in 2004, 68 percent; 81 percent in 2005; 74 percent in 2006; in 2007, 79 percent; in 2008, 92 percent and in 2009, 62 percent.

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The decrease in 2009 compared to 2008 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2009, prices were greater than, or equal to, $30 less frequently than in 2008 as the simple average LMP was $37.00 per MWh in 2009 compared to $66.12 per MWh in 2008. In 2000, the Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 42 percent of all hours. In 2001, this was 42 percent; in 2002, 33 percent; in 2003, 60 percent; in 2004, 72 percent; in 2005, 86 percent; in 2006, 80 percent; in 2007, 84 percent; in 2008, 96 percent and in 2009, 69 percent.

Average price levels in 2009 were significantly lower than in 2008 and, as a result, net revenue levels were lower for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. The distribution of prices reflects a number of factors including load levels and fuel costs. Load levels in 2009 were lower compared to those in 2008, and fuel costs decreased significantly. An efficient CT could have produced energy at an average cost of $30 in 1999, compared to $110 in 2008 and $60 in 2009. An efficient CC could have produced energy at an average cost of $20 in 1999, compared to $70 in 2008 and $35 in 2009. An efficient CP could have produced energy at an average cost of $20 in 1999, $45 in 2008 and $30 in 2009. Energy Market net revenues for a new entrant CT, CC and CP were lower in nearly all zones in 2009 due to PJM price levels decreasing more rapidly than the average prices of natural gas and delivered coal. The result is that, while natural gas-fired units and coal-fired units experienced lower marginal costs compared to 2008, the decrease in average PJM prices in 2009 was greater, meaning lower energy net revenue in most control zones for 2009.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2009

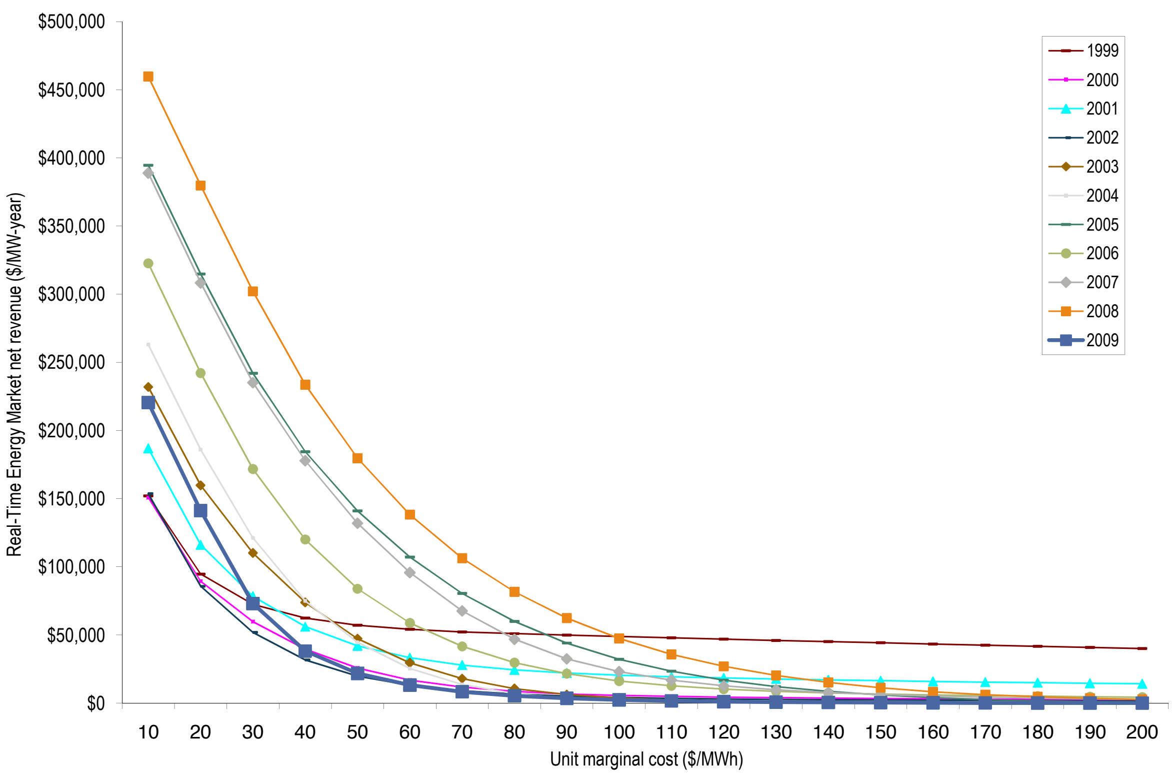
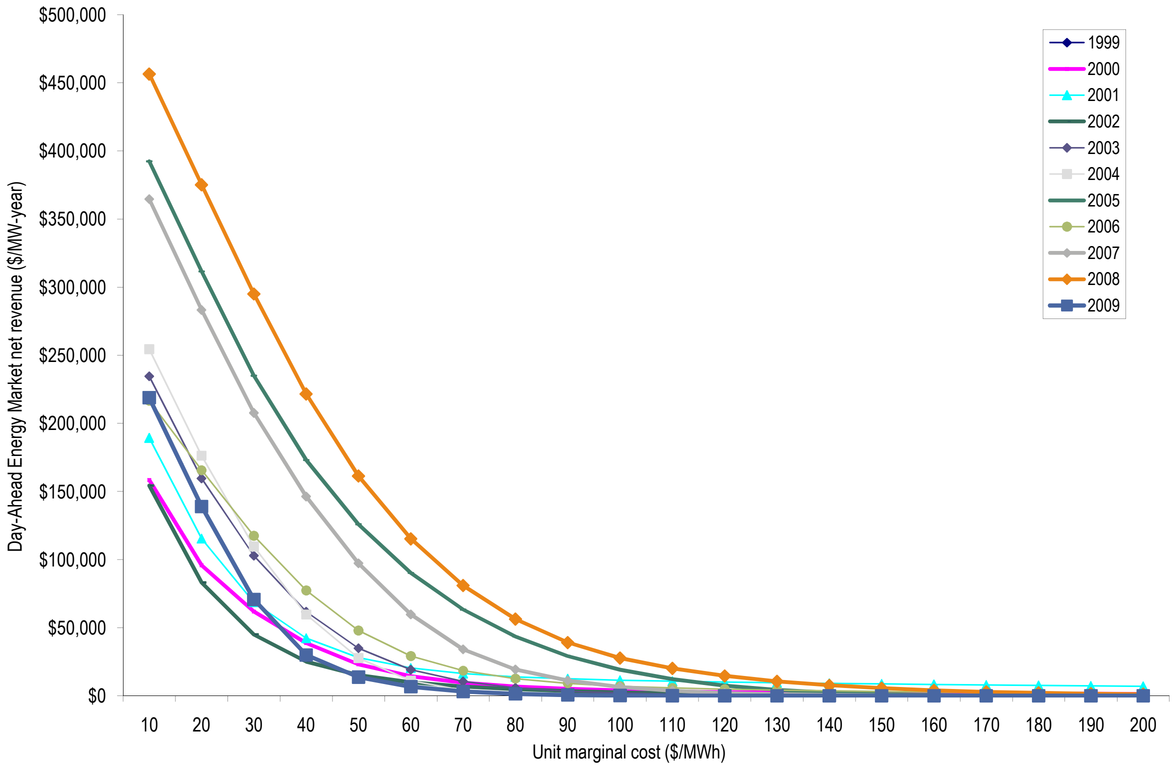


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2009



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

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

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

7 See the *2009 State of the Market Report for PJM*, Volume II, Section 2, “Energy Market, Part 1,” at “Load and LMP” and Appendix C, “Energy Market” for detailed data on prices and their annual distribution.

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

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a steam unit would generally reduce the significance of the issue.[9] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue hours.

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

Capacity Market Net Revenue

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

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive a daily capacity payment of an amount determined by the first RPM Auction (June 1, 2007, through May 31, 2008) for their corresponding locational delivery area (LDA). The RPM auction clearing prices, applied from June 1, 2008 through May 31, 2009 were: $111.92 per MW-day for RTO, $148.80 per MW-day for EMAAC or $31,843 and $210.11 per MW-day in. The 2009/2010 RPM auction clearing prices, applied from June 1, 2009 through May 31, 2010 were: $102.04 per MW-day for RTO, $191.32 per MW-day for MAAC+APS and $237.33 per MW-day for SWMAAC. Calendar year 2009 capacity revenues are a sum of five months or 151 days at the 2008/2009 Delivery Year Market Clearing Prices and seven months or 214 days at the 2009/2010 Delivery Year Market Clearing Prices. These revenues are shown by zone and LDA in Table 3-3.[10]

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

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

Table 3-3 2009 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2009

		Delivery Year 2008/2009		Delivery Year 2009/2010		
Zone	LDA	$/MW-Day	$/MW in 2009	$/MW-Day	$/MW in 2009	2009 Total
AECO	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
AEP	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
AP	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
BGE	SWMAAC	$210.11	$31,727	$237.33	$50,789	$82,515
ComEd	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
DAY	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
DLCO	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
Dominion	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
DPL	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
JCPL	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
Met-Ed	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
PECO	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
PENELEC	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
Pepco	SWMAAC	$210.11	$31,727	$237.33	$50,789	$82,515
PPL	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
PSEG	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
RECO	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
PJM	N/A	$124.58	$18,812	$138.46	$29,630	$48,441

Table 3-4 shows zonal capacity revenue for the eleven-year period 1999 to 2009.[11] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period.[12] Capacity revenue for 2009 reflects the second full year under the RPM construct, with five months of the 2008/2009 auction clearing price and seven months of the 2009/2010 auction clearing price.[13] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[14]

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

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

13 The 2007 total revenue associated with capacity for PJM in Table 3-4 similarly combines load-weighted CCM and RPM revenues. The RPM revenue for PJM in 2007-2009 is a load-weighted average based on all the LDA-clearing prices in Table 3-3 and the MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year throughout the PJM footprint, not exclusively the RTO LDA.

14 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-9, Table 3-11 and Table 3-13 as capacity revenues by technology type are adjusted for technology-specific outage rates.

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Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$10,131
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$9,109
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$20,605
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$27,928	$35,836	$10,511
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$10,131
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$10,131
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$27,928	$35,836	$12,812
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$13,647
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$13,647
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$20,605
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$13,647
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$18,915
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$37,095	$44,814	$16,706

New Entrant Net Revenues

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

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, duct burners, a 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 Virginia sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NO_x control, a Flue Gas Desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.

All net revenue calculations include the effect of actual hourly local ambient air temperature[15] on plant heat rates[16] and generator output for each of the three plant configurations.[17] Plant heat

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

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

17 Pasteris Energy, Inc.

rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.[18] The effect of ambient air conditions on plant generation capability was calculated hourly.

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.[19] 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.[20] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a continuous 15 day planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $7.09 per MWh for the CT plant, $3.07 per MWh for the CC plant and $2.97 per MWh for the CP plant. These estimates were provided by a consultant to the MMU.[21] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[22] The delivered fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[23] Coal delivered cost was developed from the published prompt-month price, adjusted for rail transportation cost.[24] The average delivered fuel prices are shown in Table 3-5.

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. Steam units do provide Tier 1 synchronized reserve, but the 2009 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules.[25] 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

18 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.
19 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
20 Outage figures obtained from the PJM eGADS database.
21 Pasteris Energy, Inc.
22 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.
23 Gas daily cash prices obtained from Platts.
24 Coal prompt prices obtained from Platts.
25 The adder reflects the modifications to the regulation market rules that were effective on December 1, 2008.

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reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2009, for CTs, the calculated rate is $2,384 per installed MW-year; for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.[26]

Table 3-5 Average delivered fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2009

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74
2005	$9.73	$2.88
2006	$7.40	$2.68
2007	$7.87	$2.53
2008	$9.95	$4.60
2009	$4.73	$3.16

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2009 is shown in Table 3-6, Table 3-7 and Table 3-8 for new entrant CT, CC and CP facilities. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP and delivered fuel costs.[27] The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

26 The CT plant reactive revenues are based on 44 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 27 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on 18 recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2008 State of the Market Report for PJM* to include new generation filings.

27 Zonal net revenues for 2009 reflect the estimated average delivered fuel costs associated with each zone and increased locational fuel cost detail compared to prior years. As a result, differences in zonal energy net revenue in 2009 compared to prior years may reflect changes in estimated fuel costs in addition to changes in fuel price fundamentals.

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$65,046	$10,735	$27,264
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$4,458	$3,206	$3,780
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$17,701	$12,546	$9,399
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$47,525	$14,995	$25,937
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$4,886	$2,393	$5,086
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$4,672	$2,981	$3,713
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$7,746	$4,704	$5,666
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$43,465	$14,319	$32,067
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$35,422	$13,410	$24,143
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$35,166	$11,622	$22,918
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$25,498	$10,057	$20,149
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$27,081	$9,513	$20,393
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$5,953	$6,019	$11,658
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$54,838	$23,362	$28,263
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$21,531	$8,970	$17,070
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$28,809	$9,155	$21,610
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$23,966	$7,846	$14,092
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$12,442	$5,113	$15,015

Table 3-7 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$154,085	$48,544	$70,798
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$29,194	$25,145	$23,711
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$68,874	$52,645	$43,385
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$133,647	$55,496	$66,389
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$30,764	$18,839	$28,880
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$29,754	$25,301	$23,331
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$28,813	$26,316	$23,472
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$123,330	$53,240	$91,458
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$117,134	$52,338	$64,563
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$126,738	$50,649	$64,049
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$99,239	$44,671	$56,311
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$102,673	$44,636	$57,355
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$44,971	$38,615	$38,238
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$144,783	$71,539	$70,164
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$92,238	$42,046	$50,860
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$119,564	$47,113	$66,053
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$108,670	$43,137	$65,528
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$62,039	$31,581	$44,841

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Table 3-8 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$337,789	$92,287	$183,685
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$152,316	$29,034	$120,984
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$257,660	$62,730	$173,838
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$309,846	$47,837	$174,177
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$203,863	$53,680	$132,691
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$130,757	$40,214	$115,072
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$138,614	$36,538	$108,592
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$282,137	$52,969	$221,748
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$320,362	$44,299	$175,488
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$315,991	$81,687	$174,128
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$282,260	$64,568	$163,533
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$290,745	$82,938	$168,308
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$239,391	$84,807	$143,232
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$328,211	$76,426	$180,824
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$286,355	$78,012	$159,048
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$248,728	$105,739	$179,178
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$259,424	$78,553	$212,148
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$179,457	$49,022	$141,074

New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[28] for at least two hours during each four-hour block.[29] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.[30]

28 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 11 (December 2, 2009), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

29 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.

30 The calculation of operating reserve payments does not reflect changes to operating reserves rules effective December 1, 2008.

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-9 for the years 1999 through 2009. This table shows the contribution of each market individually to the new entrant CT's total net revenue. The increase in capacity revenue is a result of a higher market clearing prices in the 2009/2010 delivery year.

Table 3-9 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532
2009	$5,113	$48,441	$0	$0	$2,384	$55,939

Table 3-10 shows the total net revenue (the Total column in Table 3-9) for the new entrant CT in each zone.[31] For the eleven-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $36,064 per installed MW-year.

Table 3-10 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$122,598	$70,287	$51,713
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$33,727	$42,852	$21,267
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$46,970	$67,387	$26,539
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$115,532	$99,894	$53,484
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$34,155	$43,514	$23,179
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,046	$33,941	$44,101	$21,494
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$30,782	$53,923	$37,015	$45,825	$34,501
Dominion	NA	NA	NA	NA	NA	NA	NA	$9,360	$20,075	$72,734	$55,440	$39,402
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$92,974	$79,206	$49,160
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$92,718	$77,418	$47,935
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$54,767	$70,283	$39,402
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$84,633	$75,308	$45,409
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,227	$35,222	$66,246	$30,911
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,912	$122,845	$108,262	$55,810
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$50,800	$69,197	$36,323
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$86,361	$74,951	$46,626
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$81,518	$73,641	$40,783
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$50,532	$55,939	$36,064

31 New entrant CT zonal net revenue for 2009 reflects the estimated zonal, daily delivered price of natural gas.

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New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[32] If there were not eight economic hours in any given day, then the CC was not dispatched. For every hour the plant is dispatched, the applicable LMP is compared to the incremental costs of duct burner firing, including fuel and, if applicable, emissions allowance credits.[33] If LMP is greater than or equal to the incremental costs of duct-firing for any hour the plant is operating, the duct burner is dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-7 results.

Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-11 for the years 1999 through 2009. This table shows the contribution of each market individually to the new entrant CC's total net revenue. The increase in capacity revenue is a result of a higher market clearing prices in the 2009/2010 delivery year.

Table 3-11 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928
2009	$31,581	$46,596	$0	$0	$3,198	$81,376

Table 3-12 shows the total net revenue (the Total column in Table 3-11) for the new entrant CC in each zone. For the eleven-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $66,824 per installed MW-year.

32 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 11 (December 2, 2009), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

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

Table 3-12 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$217,072	$112,738	$96,925
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$61,521	$65,604	$42,672
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$101,201	$111,482	$62,286
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$207,969	$138,066	$95,046
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$63,092	$59,298	$48,183
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$62,081	$65,760	$42,291
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$83,104	$155,267	$61,141	$66,775	$76,455
Dominion	NA	NA	NA	NA	NA	NA	NA	$23,734	$44,520	$155,658	$93,699	$79,403
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$110,969	$180,121	$116,532	$87,753
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$189,725	$114,843	$90,176
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$131,566	$103,508	$76,227
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$165,660	$108,830	$83,482
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$77,299	$97,452	$58,154
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$219,105	$154,109	$98,821
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$124,566	$100,883	$70,776
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$182,551	$111,307	$92,180
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$171,658	$107,331	$93,862
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$103,928	$81,376	$66,824

New Entrant Coal Plant

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

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-13 for the years 1999 through 2009. This table shows the contribution of each market individually to the new entrant CP's total net revenue. The increase in capacity revenue is a result of the implementation of RPM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

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Table 3-13 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144
2009	$49,022	$43,931	$0	$231	$1,783	$94,968

Table 3-14 shows the total net revenue (the Total column 7 in Table 3-13) for the new entrant CP in each zone.[34] For the eleven-year period, the average total net revenue under the economic dispatch scenario was $163,446 per installed MW-year.

Table 3-14 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$118,254	$137,752	$143,257	$121,785	$179,117	$176,827	$306,995	$233,787	$345,739	$396,564	$151,958	$210,185
AEP	NA	NA	NA	NA	NA	NA	$150,176	$127,588	$170,532	$182,201	$66,176	$139,335
AP	NA	NA	NA	NA	$152,458	$123,620	$231,963	$178,701	$255,474	$288,025	$117,241	$192,497
BGE	$115,926	$124,106	$116,306	$119,714	$173,476	$148,097	$303,218	$248,764	$380,425	$379,157	$124,582	$203,070
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$234,487	$91,497	$151,659
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,421	$160,462	$77,760	$133,381
DLCO	NA	NA	NA	NA	NA	NA	$125,720	$240,844	$157,544	$168,655	$73,721	$153,297
Dominion	NA	NA	NA	NA	NA	NA	NA	$108,418	$328,069	$312,361	$90,049	$209,724
DPL	$121,871	$149,240	$164,219	$125,338	$179,145	$160,037	$287,243	$213,209	$339,158	$379,198	$103,715	$202,034
JCPL	$117,951	$129,972	$133,840	$110,499	$165,751	$186,365	$290,815	$203,813	$352,520	$374,748	$141,256	$200,685
Met-Ed	$116,776	$126,376	$126,885	$115,061	$167,368	$144,386	$276,296	$210,720	$311,760	$312,370	$119,008	$184,273
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,382	$326,717	$349,522	$142,528	$194,890
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,790	$269,748	$140,148	$164,195
Pepco	$115,585	$123,766	$110,090	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$397,620	$153,255	$209,765
PPL	$117,166	$125,227	$121,146	$105,991	$162,900	$136,365	$267,023	$201,584	$291,701	$316,263	$132,526	$179,808
PSEG	$120,910	$145,675	$142,694	$112,410	$184,332	$189,717	$316,131	$224,904	$353,386	$307,268	$165,919	$205,759
RECO	NA	NA	NA	NA	$186,860	$168,414	$298,796	$219,016	$347,309	$318,225	$138,107	$239,532
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$218,144	$94,968	$163,446

34 New Entrant CP zonal net revenue for 2009 incorporates the zone specific, delivered price of coal.

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New Entrant Day-Ahead Net Revenues

In order to develop a comprehensive net revenue analysis, Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis. The results for the Day-Ahead Energy Market for each class are presented in Table 3-15, Table 3-16 and Table 3-17, respectively. [35]

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$26,001	$6,373	$12,948
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,827	$1,180	$1,411
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$6,719	$5,397	$4,463
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$27,271	$7,792	$10,689
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$1,984	$480	$1,788
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,628	$733	$1,189
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$22,582	$7,613	$14,066
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$1,428	$1,098	$1,300
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$19,152	$6,840	$11,733
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$14,163	$5,007	$9,424
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$12,492	$4,619	$9,013
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$12,688	$4,920	$9,573
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$4,535	$3,303	$5,154
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$32,677	$15,816	$12,744
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$10,351	$4,345	$7,424
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$13,686	$4,051	$9,611
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$11,445	$3,156	$5,820
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$6,623	$1,966	$6,658

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

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Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$115,974	$51,240	$54,717
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$20,140	$23,139	$17,130
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$50,885	$47,963	$33,276
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$118,704	$58,133	$48,711
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$24,163	$14,225	$19,271
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$19,147	$21,226	$15,502
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$101,261	$21,270	$65,143
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$15,605	$21,270	$15,771
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$101,261	$52,846	$50,157
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$112,307	$50,315	$48,767
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$84,379	$44,189	$41,733
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$85,673	$46,590	$44,348
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$39,701	$38,970	$27,697
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$133,227	$73,603	$53,507
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$77,511	$41,987	$37,581
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$106,457	$47,111	$50,946
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$96,618	$41,780	$54,862
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$47,342	$28,360	$30,060

Table 3-17 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$323,135	$95,836	$168,520
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$149,397	$23,732	$115,195
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$250,837	$55,868	$165,999
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$312,579	$48,315	$158,085
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$210,403	$48,765	$130,118
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$123,738	$33,606	$106,239
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$277,629	$51,927	$208,815
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$139,537	$28,243	$99,573
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$324,485	$42,395	$164,827
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$320,484	$81,671	$162,135
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$286,549	$63,430	$152,167
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$297,666	$86,272	$160,240
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$251,168	$86,110	$134,988
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$333,200	$76,927	$165,671
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$291,459	$78,730	$149,580
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$250,151	$108,656	$166,312
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$315,939	$78,117	$212,623
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$174,191	$45,844	$128,679

For the ten-year period, the average PJM Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario for the CT plant was $6,658 per installed MW-year. For the CC plant, the ten-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $30,060 per installed MW-year. For the CP plant, the ten-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $128,679 per installed MW-year.

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-18, Table 3-19 and Table 3-20 for the CT, CC and CP plants.

On average, the Real-Time Energy Market net revenue was 39 percent higher than the Day-Ahead Market net revenue for the CT plant, 20 percent higher for the CC plant and 3 percent higher for the CP.[36]

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
Avg.	$10,956	$6,658	$4,298	39%

Table 3-19 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2009

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
Avg.	$41,271	$33,066	$8,205	20%

36 The Day-Ahead Energy Market was implemented on June 1, 2000. For the analysis presented in Table 3-18, Table 3-19 and Table 3-20, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

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Table 3-20 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2009

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
Avg.	$145,888	$141,547	$4,341	3%

Net Revenue Adequacy

To put the 2009 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2009.[37] The estimated, 20-year levelized fixed costs[38] are $128,705 per installed MW-year for the new entrant CT plant,[39] $173,174 per installed MW-year for the new entrant CC plant and $446,550 per installed MW-year for the new entrant CP plant.[40] Levelized fixed costs increased significantly for all three technologies. Table 3-21 shows the 20-year levelized costs for each technology for the period 2005 through 2009.[41] The increased costs of constructing generation facilities from 2005 through 2008 are the result of a combination of factors, including increased worldwide demand in recent years. The estimated levelized fixed costs for 2009 show a smaller increase than in prior years, indicating a potential reduction in upward pressure on the costs of constructing generation facilities.

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

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

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705
CC	$93,549	$99,230	$143,600	$171,361	$173,174
CP	$208,247	$267,792	$359,750	$492,780	$446,550

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

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

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

40 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2009.

41 The figures in Table 3-21 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Mid-Atlantic Region.

In 2009, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $55,939 per installed MW-year. The associated operating costs were between $55 and $60 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $4.73 per MBtu and a VOM rate of $7.09 per MWh.[42] The average PJM net revenue in 2009 would not have covered the fixed costs of a new CT. As shown in Table 3-22, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999. However, some zonal net revenues were sufficient to cover the fixed costs for a new CT in several prior years.

Table 3-22 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
2008	$123,640	$50,532	41%
2009	$128,705	$55,939	43%
Average	$84,433	$36,064	43%

Table 3-23 includes the 20-year levelized fixed cost in 2009 for a new entrant CT, the economic dispatch net revenue for each zone in 2009 and average net revenue and average fixed costs for the period 1999 to 2009. There are no control zones with net revenue sufficient to cover 100 percent of the 2009 levelized fixed costs. The net revenues in Pepco and in BGE control zones of the SWMAAC LDA show the highest percentage of levelized fixed costs recovery at 84 and 78 percent respectively. Figure 3-3 summarizes the information in Table 3-23, showing the 2009 average net revenue for a new entrant CT, the zonal net revenue for the period 1999 to 2009 and the levelized 2009 fixed cost for a new entrant CT. The extent to which net revenues cover the levelized fixed costs of investment in the CT technology is significantly dependent on location, which affects both energy and, with the locational capacity prices, capacity revenue. Total net revenues in 2009 are higher than the eleven year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CT technology. Figure 3-4 shows zonal net revenue for the new entrant CT by LDA with the applicable yearly levelized fixed costs for the period 1999-2009.

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

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Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	2009			11-Year Average (1999-2009)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$70,287	$128,705	55%	$51,713	$84,433	61%
AEP	$42,852	$128,705	33%	$21,267	$84,433	25%
AP	$67,387	$128,705	52%	$26,539	$84,433	31%
BGE	$99,894	$128,705	78%	$53,484	$84,433	63%
ComEd	$43,514	$128,705	34%	$23,179	$84,433	27%
DAY	$44,101	$128,705	34%	$21,494	$84,433	25%
DLCO	$45,825	$128,705	36%	$34,501	$84,433	41%
Dominion	$55,440	$128,705	43%	$39,402	$84,433	47%
DPL	$79,206	$128,705	62%	$49,160	$84,433	58%
JCPL	$77,418	$128,705	60%	$47,935	$84,433	57%
Met-Ed	$70,283	$128,705	55%	$39,402	$84,433	47%
PECO	$75,308	$128,705	59%	$45,409	$84,433	54%
PENELEC	$66,246	$128,705	51%	$30,911	$84,433	37%
Pepco	$108,262	$128,705	84%	$55,810	$84,433	66%
PPL	$69,197	$128,705	54%	$36,323	$84,433	43%
PSEG	$74,951	$128,705	58%	$46,626	$84,433	55%
RECO	$73,641	$128,705	57%	$40,783	$84,433	48%
PJM	$55,939	$128,705	43%	$36,064	$84,433	43%

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Figure 3-3 New entrant CT real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009

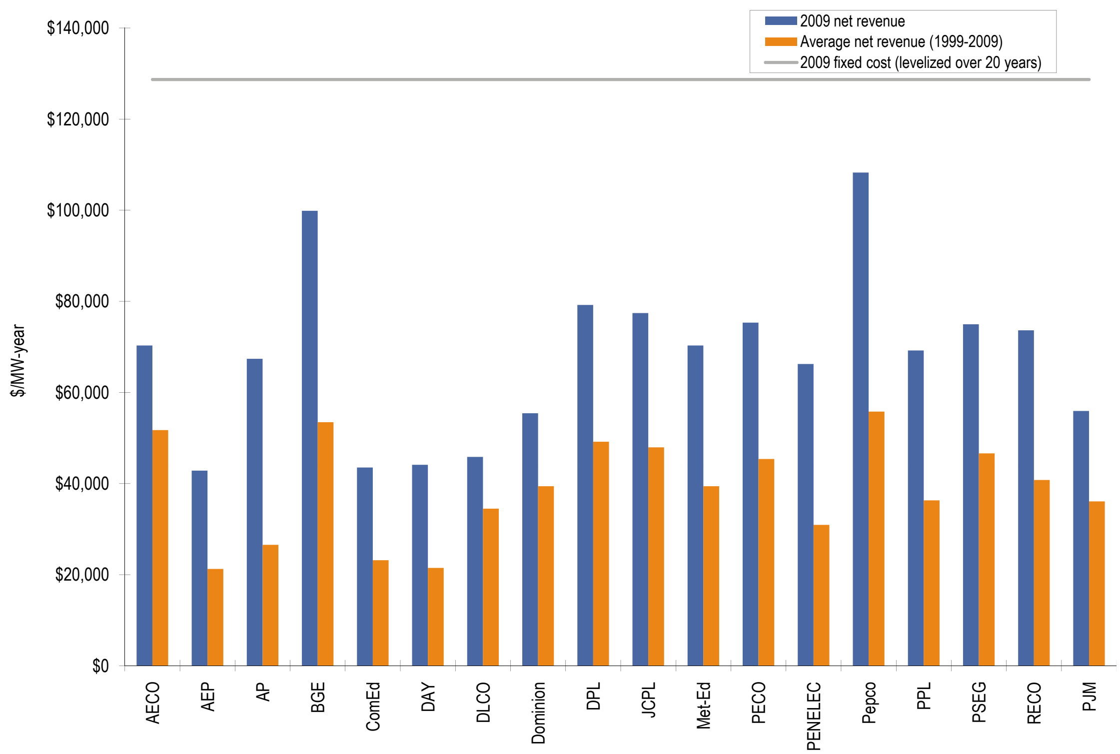

Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009

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In 2009, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $81,376 per installed MW-year. The associated operating costs were between $35 and $40 per MWh, based on a design heat rate of 6,900 Btu per kWh, average daily delivered natural gas prices of $4.73 per MBtu and a VOM rate of $3.07 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-24 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2009. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999, but some zonal net revenues were sufficient to cover the fixed costs for a new CC in several prior years.

Table 3-24 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
2008	$171,361	$103,928	61%
2009	$173,174	$81,376	47%
Average	$112,928	$66,824	59%

Table 3-25 compares the 20-year levelized fixed cost in 2009 for a new entrant CC to the economic dispatch net revenue for each zone in 2009, along with average net revenue for the period 1999 to 2009 and average fixed costs. The average PJM net revenue is not enough to cover the levelized fixed costs. There are no control zones with net revenue sufficient to cover 100 percent of the 2009 levelized fixed costs. The net revenues in Pepco and in BGE Control Zones of the SWMAAC LDA show the highest percentage of levelized fixed costs recovery at 89 and 80 percent, respectively. Figure 3-5 summarizes the information in Table 3-25, showing the 2009 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2009 by zone and the levelized 2009 capital cost for a new entrant CC.[43] The extent to which net revenues cover the levelized fixed costs of investment in the CC technology is significantly dependent on location, which affects both energy and, with locational capacity prices, capacity revenue. Total net revenues in 2009 are higher than the eleven year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CC technology. Figure 3-6 shows zonal net revenue for the new entrant CC by LDA with the applicable yearly levelized fixed costs for the period 1999-2009.

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

Table 3-25 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	2009			11-Year Average (1999-2009)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$112,738	$173,174	65%	$96,925	$112,928	86%
AEP	$65,604	$173,174	38%	$42,672	$112,928	38%
AP	$111,482	$173,174	64%	$62,286	$112,928	55%
BGE	$138,066	$173,174	80%	$95,046	$112,928	84%
ComEd	$59,298	$173,174	34%	$48,183	$112,928	43%
DAY	$65,760	$173,174	38%	$42,291	$112,928	37%
DLCO	$66,775	$173,174	39%	$76,455	$112,928	68%
Dominion	$93,699	$173,174	54%	$79,403	$112,928	70%
DPL	$116,532	$173,174	67%	$87,753	$112,928	78%
JCPL	$114,843	$173,174	66%	$90,176	$112,928	80%
Met-Ed	$103,508	$173,174	60%	$76,227	$112,928	68%
PECO	$108,830	$173,174	63%	$83,482	$112,928	74%
PENELEC	$97,452	$173,174	56%	$58,154	$112,928	51%
Pepco	$154,109	$173,174	89%	$98,821	$112,928	88%
PPL	$100,883	$173,174	58%	$70,776	$112,928	63%
PSEG	$111,307	$173,174	64%	$92,180	$112,928	82%
RECO	$107,331	$173,174	62%	$93,862	$112,928	83%
PJM	$81,376	$173,174	47%	$66,824	$112,928	59%

Figure 3-5 New entrant CC real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009

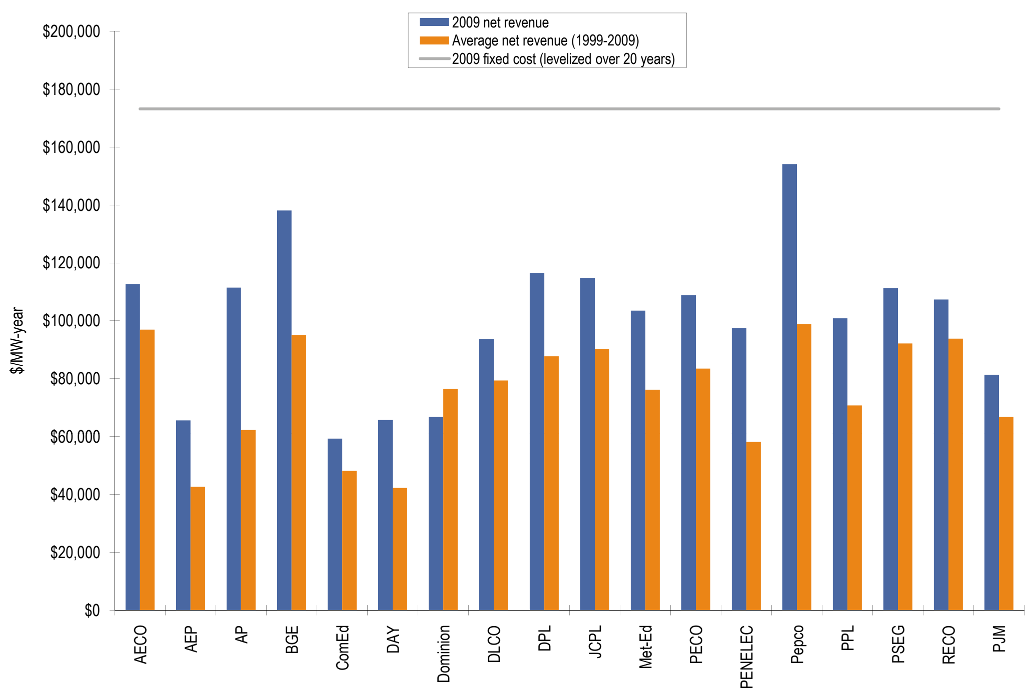

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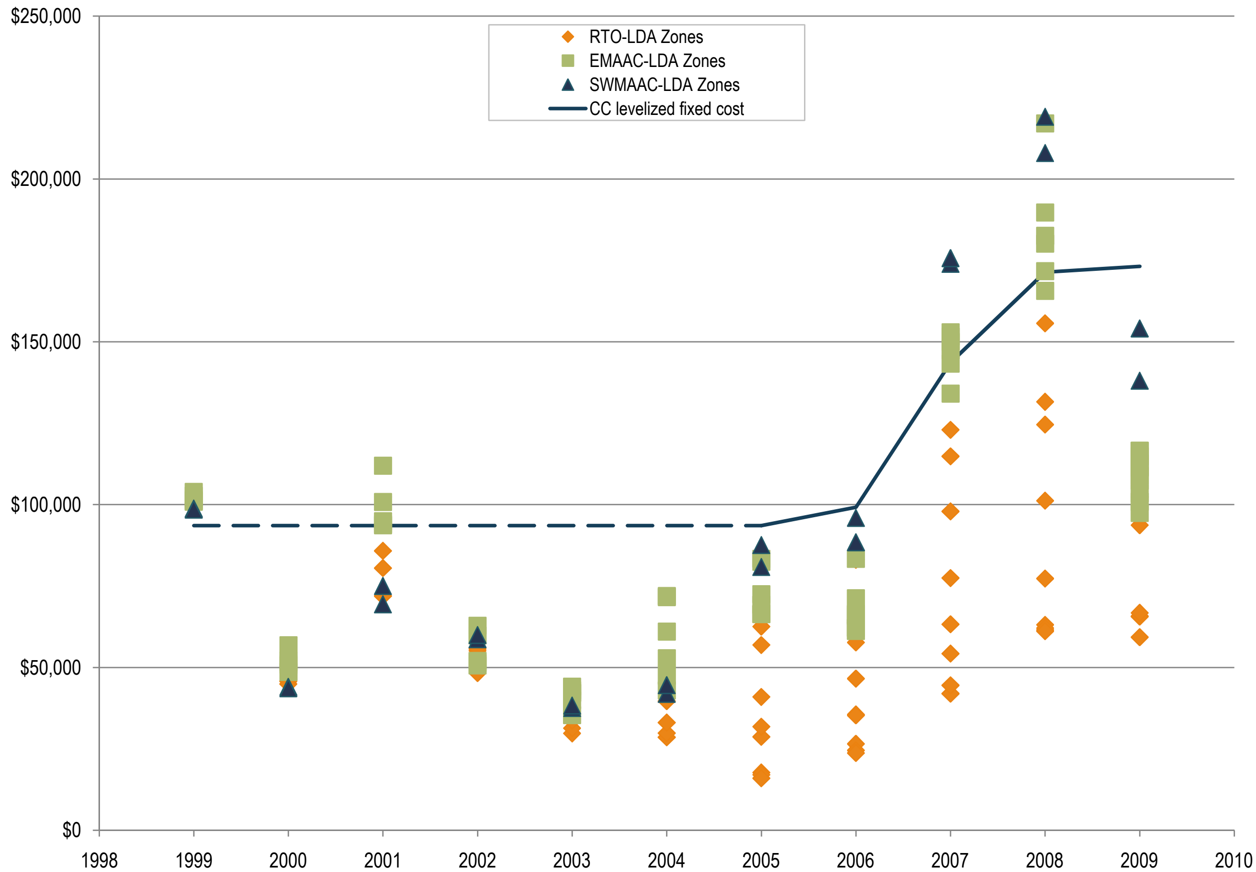
Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009



In 2009, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $94,968 per installed MW-year. The associated operating costs were between $30 and $35 per MWh, based on a design heat rate of 9,100 Btu per kWh, average delivered coal prices of $3.16 per MBtu and a VOM rate of $2.97 per MWh.[44] Table 3-26 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2009. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005. However, several zonal net revenues were sufficient to cover the fixed costs for a new CP in 2007. Average 2009 net revenue for a CP show a significant decrease from 2008 reflecting the lower average energy price levels in PJM and the more substantial impact of energy market net revenues for the CP technology.

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

Table 3-26 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
2008	$492,780	$218,144	44%
2009	$446,550	$94,968	21%
Average	$274,964	$163,446	59%

Table 3-27 compares the 20-year levelized fixed cost in 2009 for a new entrant CP to the economic dispatch net revenue for each zone in 2009, along with average net revenue for the period 1999 to 2009 and average fixed costs. There were no control zones with sufficient net revenue to cover the 2009 levelized fixed costs. Figure 3-7 summarizes the information in Table 3-27, showing the 2009 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2009 by zone and the levelized 2009 capital cost for a new entrant CP.[45] For every zone, 2009 energy net revenues for a CP are lower than 2008, which is partially offset by higher capacity revenues.[46] The extent to which net revenues cover the levelized fixed costs of investment in the CP technology is significantly dependent on location, which affects both energy and, with locational capacity prices, capacity revenue as well as fuel costs. There is less locational variation in 2009 for the CP technology because locational energy price differences were down substantially in 2009 and the impact of the locational capacity market price differences was attenuated by the smaller relative significance of capacity revenues for the CP technology. Total net revenues in 2009 are lower than the eleven year average for all control zones, and this is driven by lower energy price levels and lower energy net revenues, which comprises a significant portion of total revenue for the CP technology. The Figure 3-8 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed costs for the period 1999-2009.

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

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

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Table 3-27 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	2009			11-Year Average (1999-2009)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$151,958	$446,550	34%	$210,185	$274,964	76%
AEP	$66,176	$446,550	15%	$139,335	$274,964	51%
AP	$117,241	$446,550	26%	$192,497	$274,964	70%
BGE	$124,582	$446,550	28%	$203,070	$274,964	74%
ComEd	$91,497	$446,550	20%	$151,659	$274,964	55%
DAY	$77,760	$446,550	17%	$133,381	$274,964	49%
DLCO	$73,721	$446,550	17%	$153,297	$274,964	56%
Dominion	$90,049	$446,550	20%	$209,724	$274,964	76%
DPL	$103,715	$446,550	23%	$202,034	$274,964	73%
JCPL	$141,256	$446,550	32%	$200,685	$274,964	73%
Met-Ed	$119,008	$446,550	27%	$184,273	$274,964	67%
PECO	$142,528	$446,550	32%	$194,890	$274,964	71%
PENELEC	$140,148	$446,550	31%	$164,195	$274,964	60%
Pepco	$153,255	$446,550	34%	$209,765	$274,964	76%
PPL	$132,526	$446,550	30%	$179,808	$274,964	65%
PSEG	$165,919	$446,550	37%	$205,759	$274,964	75%
RECO	$138,107	$446,550	31%	$239,532	$274,964	87%
PJM	$94,968	$446,550	21%	$163,446	$274,964	59%

Figure 3-7 New entrant CP real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009

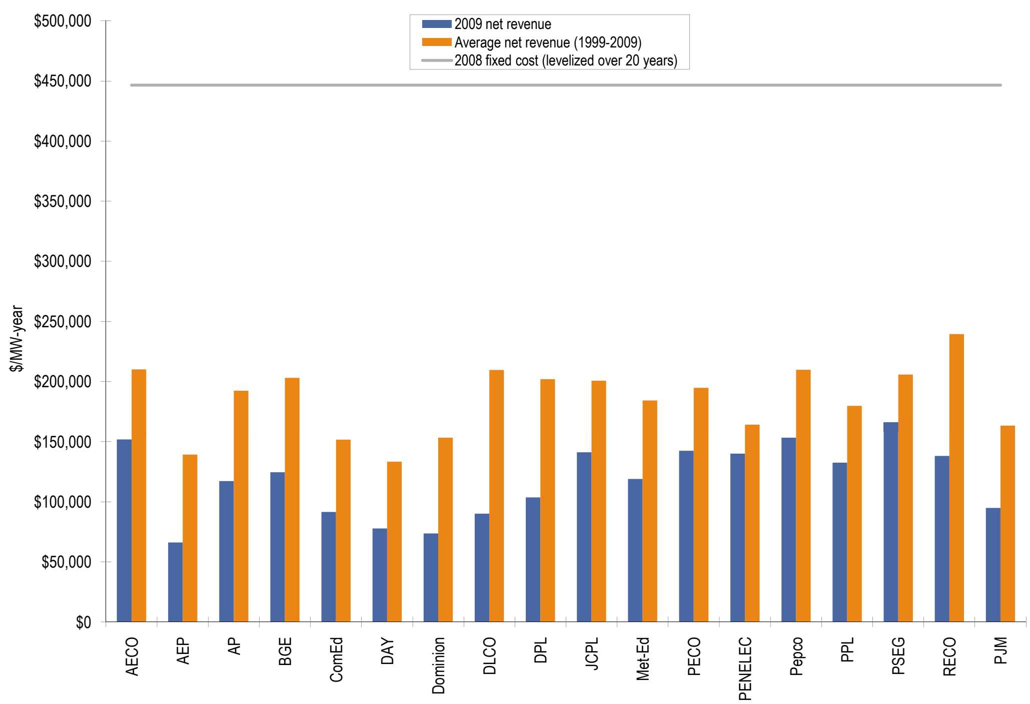
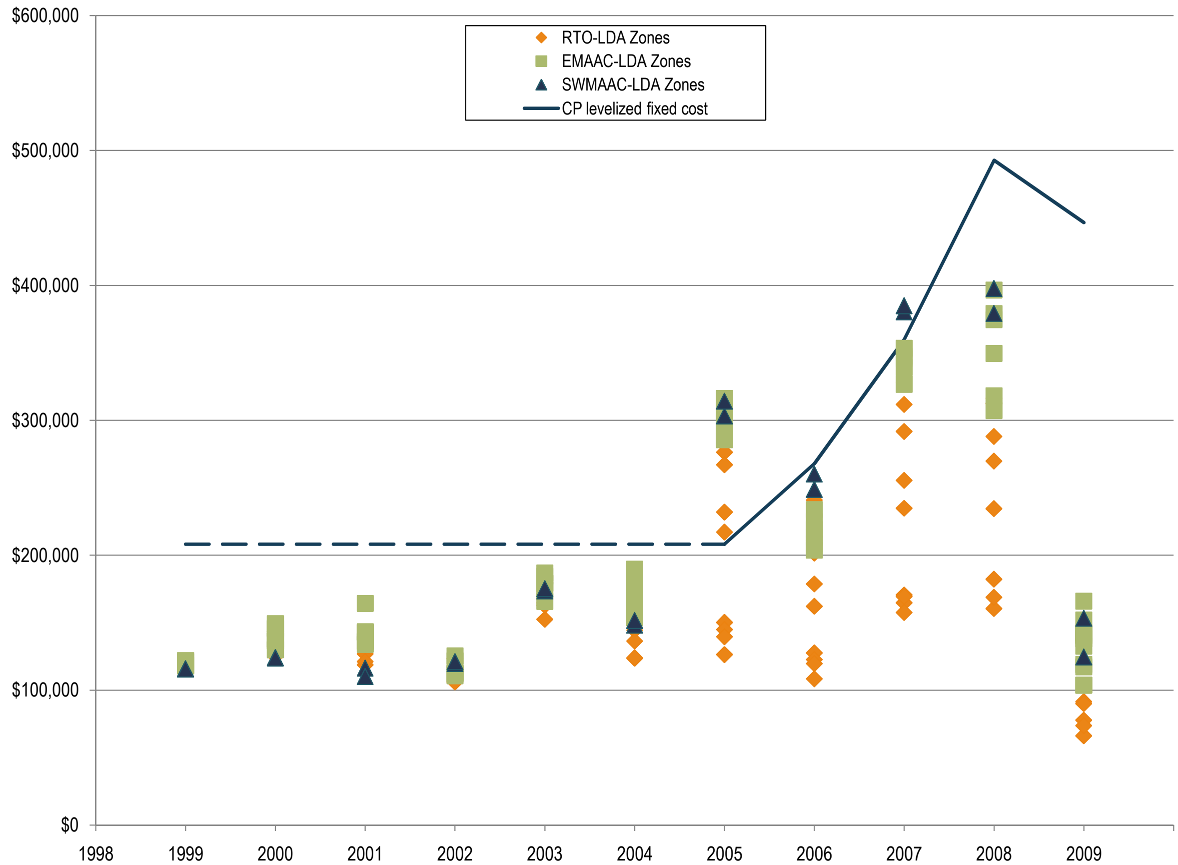


Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009



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 2009 net revenue indicates that, in years when energy markets are long and energy prices low, the contribution of capacity revenue from the RPM has a more significant effect on the incentive to invest in a new entrant CT or CC. The profitability of new entrant peaking units, specifically, is substantially impacted by the local capacity market clearing price. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. The delivered price of natural gas showed a more significant decrease at about 52.4 percent, than did the delivered price of coal, which decreased by about 31.4 percent. [47] As a result, the natural gas fired power plants, particularly the more efficient combined cycle, show lower percentage decreases in energy net revenues from 2008 than the coal-fired power plant. There are no control zones with net revenue sufficient to cover 100 percent of the

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

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2009 levelized fixed costs. The net revenues in Pepco and BGE Control Zones of the SWMAAC LDA show the highest percent of the levelized fixed cost recovery for all technologies. Net revenue from the combined cycle technology shows the highest percentage of 20-year levelized fixed cost recovery, while the coal plant technology shows the lowest percentage of levelized fixed cost recovery.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2009. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, there may be a lag in Capacity Market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity Market prices are a function of a three year historical average net revenue offset which can be an inaccurate estimate of actual net revenues in the current operating year. In 2009 Capacity Market prices and revenues were relatively high but not enough to fully offset the decline in energy revenues for CTs. Energy net revenues decreased significantly in most PJM Control zones, but that decrease is not reflected in higher Capacity Market prices.

The net revenue performance of combined cycle units (CCs) was comparable to that of CTs. CCs, like CTs, burn gas but are more efficient than CTs. Thus, as clearing prices set by CTs decline, net revenues from the Energy Market decline for CCs. However, with lower gas prices in 2009, and with the spread between the delivered price of natural gas and the delivered price of coal decreasing, there are hours in which the CC has lower generating costs than the CP. In these cases, when the CP is marginal, the CC will experience inframarginal energy revenues.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs. But with natural gas prices decreasing more than coal prices, these inframarginal energy revenues were lower than in 2007 and 2008. Similarly, with lower gas prices in 2009, and with the spread between the delivered price of natural gas and the delivered price of coal decreasing, there are hours in which the CC has lower generating costs than the CP. The CP, which has significant operating constraints, may continue running during hours when a CC is marginal and net revenues are negative.

The returns earned by investors in generating units are a direct function of net revenues. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 3-21. Levelized net revenues were modified and the IRR calculated. A $7,500 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $30,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-28.[48]

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

Table 3-28 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$136,205	13.5%	$183,174	13.5%	$476,550	13.8%
Base Case	$128,705	12.0%	$173,174	12.0%	$446,550	12.0%
Sensitivity 2	$121,205	10.4%	$163,174	10.4%	$416,550	10.2%
Sensitivity 3	$113,705	8.7%	$153,174	8.8%	$386,550	8.3%
Sensitivity 4	$106,205	6.9%	$143,174	7.1%	$356,550	6.2%
Sensitivity 5	$98,705	4.9%	$133,174	5.3%	$326,550	4.0%
Sensitivity 6	$91,205	2.7%	$123,174	3.4%	$296,550	1.6%

Actual Net Revenue

The net revenues presented in this section are based on an analysis of actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement. When other factors are considered, including additional fixed and variable costs associated with complying with environmental mandates, this is a key first measure.

The MMU calculated unit specific energy and ancillary net revenues within several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the applicable capacity revenues, depending on the actual location of the unit, and compared to avoidable costs to determine the extent to which the Reliability Pricing Model covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Energy net revenues presented in this section include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

Net revenues were analyzed for six technologies: (1) two on one Frame F combined cycles, (2) third generation aero-derivative combustion turbines, (3) third generation Frame F combustion turbines, (4) nuclear generators, (5) sub-critical coal burning units and (6) super critical coal units.

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The underlying analysis is done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. For purposes of reporting the results, the data is aggregated by quartile to ensure that confidential data is not released. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis. Table 3-29 shows average energy and ancillary service net revenues by quartile, along with the class average, for these technology classes.

Table 3-29 Average energy and ancillary service net revenue by quartile for select technologies for calendar year 2009

Technology	First Quartile Average Energy and Ancillary Net Revenue	Second Quartile Average Energy and Ancillary Net Revenue	Class Average Energy and Ancillary Net Revenue	Third Quartile Average Energy and Ancillary Net Revenue	Fourth Quartile Average Energy and Ancillary Net Revenue
CC - Two on One Frame F Technology	($20,161)	$10,533	$15,386	$26,922	$39,200
CT - Third Generation Aero (GE LM 6000)	$2,294	$3,396	$10,350	$12,546	$21,076
CT - Third Generation Frame F	$44	$2,426	$5,002	$4,084	$13,125
Nuclear	$124,536	$194,122	$229,466	$270,254	$311,418
Sub-Critical Coal	($6,609)	$14,418	$34,361	$36,632	$91,551
Super Critical Coal	$9,435	$21,306	$40,434	$41,086	$84,546

The first quartiles for the combined cycle and sub-critical coal technologies show negative net energy revenues at -$20,161 per MW-year and -$6,609 per MW-year. This does not imply that all units in the first quartile for these technologies show negative net revenues. It does mean, however, that the average energy and ancillary service net revenue for the lowest 25 percent of units is negative and that a proportion of units operate in PJM energy markets at a net loss. This results, for example, when a unit runs during unprofitable hours independent of PJM dispatch. For some older units, this may occur because of an inability to follow PJM dispatch. In other cases, a unit may have an incentive to run during hours when LMP is lower than operating costs because it is receiving revenues from outside PJM markets, via a bilateral agreement.

The MMU calculated average avoidable costs in dollars per MW-year for each quartile based on actual submitted Avoidable Cost Rate (ACR) data for units within a quartile associated with the most recent 2008/2009 and 2009/2010 RPM Auctions.[49] For units that did not submit ACR data, the default ACR was used. Avoidable costs were calculated for calendar year 2009 using the 2008/2009 avoidable cost data for 151 days and the 2009/2010 delivery year avoidable for 214 days.

An estimated annual avoidable cost rate for nuclear units was developed by Pasteris Energy, Inc from publicly available information and used to determine an avoidable cost proxy for all nuclear units.[50] While avoidable costs for the CT, CC and CP technologies are quartile specific averages

49 If a unit submitted updated ACR data for an incremental auction for either the 2008/2009 or the 2009/2010 delivery year, that data was used instead of the ACR data submitted for the associated Base Residual Auction.

50 Data from the Nuclear Energy Institute (NEI) website (http://www.nei.org/) was used to develop an avoidable cost rate based on 2008 information, which was escalated through 2009. The NEI states the "average non-fuel O&M cost for a nuclear power plant in 2008 was 1.37 cents/kWh" which includes costs "related to labor, material & supplies, contractor services, licensing fees, and miscellaneous costs such as employee expenses and regulatory fees." Property tax costs were obtained from public information. Guidelines for the determination of insurance premiums were provided by Moore-McNeil LLC Insurance Consulting of Nashville, TN. Overall labor rates for nuclear plant avoidable costs were escalated at 1 percent annually. Plant O&M was escalated using the Handy-Whitman July 1 Index for "Total Nuclear Production Plant." Property tax expense was not escalated and insurance premiums were escalated at 2.5 percent.

based on unit specific avoidable costs, the nuclear avoidable cost rate represents a class average, consistent for all nuclear units both within and across quartiles.

Table 3-30 shows the percentage recovery of avoidable cost using the quartile average energy and ancillary service net revenue. The average energy net revenues for the first three quartiles are not adequate to recover avoidable costs for either the CT technologies or CP technologies. Although the average energy net revenue is negative for first quartile for the CC, the average energy net revenue for each of the top three quartiles is sufficient to cover avoidable costs. The average energy net revenue for the nuclear technology is greater than the class average avoidable cost rate for each quartile.

Table 3-30 Avoidable cost recovery by quartile from energy and ancillary service net revenue for select technologies for calendar year 2009

Technology	First Quartile Recovery of Class Average Avoidable Costs	Second Quartile Recovery of Class Average Avoidable Costs	Class Average Recovery of Class Average Avoidable Costs	Third Quartile Recovery of Class Average Avoidable Costs	Fourth Quartile Recovery of Avoidable Costs
CC - Two on One Frame F Technology	(209.4%)	105.5%	158.4%	279.6%	407.1%
CT - Third Generation Aero (GE LM 6000)	13.2%	19.5%	60.0%	74.8%	121.1%
CT - Third Generation Frame F	0.6%	32.3%	66.7%	54.0%	174.3%
Nuclear	101.4%	158.1%	186.8%	220.1%	253.6%
Sub-Critical Coal	(12.5%)	25.7%	63.6%	67.7%	172.2%
Super Critical Coal	16.6%	37.6%	72.3%	74.9%	152.6%

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. Table 3-31 shows average energy and ancillary service net revenues plus average capacity revenues, along with the class average.[51] Table 3-31 is Table 3-29 plus average capacity revenues for the same units.

Table 3-31 Average total net revenue by quartile for select technologies for calendar year 2009

Technology	First Quartile Average Energy and Ancillary Net Revenue	Second Quartile Average Energy and Ancillary Net Revenue	Class Average Energy and Ancillary Net Revenue	Third Quartile Average Energy and Ancillary Net Revenue	Fourth Quartile Average Energy and Ancillary Net Revenue
CC - Two on One Frame F Technology	$26,764	$56,320	$61,234	$68,743	$88,186
CT - Third Generation Aero (GE LM 6000)	$41,030	$44,875	$59,280	$73,482	$74,061
CT - Third Generation Frame F	$53,051	$50,449	$52,643	$49,029	$58,070
Nuclear	$163,272	$241,842	$279,612	$323,716	$370,352
Sub-Critical Coal	$40,263	$67,171	$84,002	$87,991	$139,139
Super Critical Coal	$59,316	$65,899	$90,884	$89,376	$142,970

51 This analysis does not reflect actual RPM billing dollars, rather, it assumes each unit's installed capacity cleared in the relevant Base Residual Auctions.

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Table 3-32 shows the average avoidable cost recovery from all PJM markets by the same quartiles. Capacity payments in calendar year 2009 range from approximately $38,700 in the unconstrained RTO Control zones to $82,500 in the SWMAAC LDA. The result is that for the CC technology and both CT technologies, capacity payments alone lead to full recovery of average avoidable costs. With energy prices and load levels down significantly in 2009, most peaking units, depending on location, will not recover avoidable costs from the energy and ancillary service markets alone. Continued operation of and investment in these generation technologies in periods of low demand and low energy prices is dependent on capacity market revenue.

In some years, for some technologies, capacity payments significantly exceed the avoidable costs of running a power plant. With natural gas prices down significantly, the class average net revenue for the more efficient combined cycle was sufficient to cover avoidable costs before capacity revenues are considered. Thus, the average total net revenues, including capacity, for the third and fourth quartiles for the CC technology are between 7 and 9 times greater than the quartile average avoidable costs.

However, the average total revenue for the lowest quartile of subcritical coal units is not sufficient to cover avoidable costs and the average total revenue for the lowest quartile for supercritical coal units is just sufficient to cover avoidable costs. Avoidable costs for coal plants are considerably higher than for CTs and CCs, and, accordingly, revenues received from the capacity market make up a smaller portion of avoidable costs. As a result, the profitability of coal units is more dependent upon net revenues received in the energy market.

Table 3-32 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2009

Technology	First Quartile Recovery of Class Average Avoidable Costs	Second Quartile Recovery of Class Average Avoidable Costs	Class Average Recovery of Class Average Avoidable Costs	Third Quartile Recovery of Class Average Avoidable Costs	Fourth Quartile Recovery of Avoidable Costs
CC - Two on One Frame F Technology	277.9%	564.0%	630.5%	713.9%	915.8%
CT - Third Generation Aero (GE LM 6000)	235.8%	257.9%	343.7%	437.8%	425.7%
CT - Third Generation Frame F	719.0%	671.9%	702.1%	647.8%	771.3%
Nuclear	132.9%	196.9%	227.7%	263.6%	301.6%
Sub-Critical Coal	76.2%	119.6%	155.4%	162.6%	261.7%
Super Critical Coal	104.1%	116.3%	162.4%	163.0%	258.1%

Quartile averages can be greatly affected by outliers, and do not indicate the proportion of actual units in PJM not covering avoidable costs. Table 3-33 shows the proportion of units with full recovery of avoidable costs from energy markets and from all markets for calendar years 2007 through 2009. Capacity revenues from 2007 include actual unit specific experience in the CCM for January 1 through May 31 and zone specific RPM revenue streams for June 1 through December 31. Calendar year 2008 was the first full year of RPM capacity payments. In each year, a portion of units for the CC, CT and sub-critical CP technologies do not achieve full recovery of avoidable costs through energy markets alone.

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Table 3-33 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2007 through 2009

	2007		2008		2009	
Technology	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets
CC - Two on One Frame F Technology	74%	90%	74%	100%	63%	93%
CT - Third Generation Aero (GE LM 6000)	45%	79%	41%	100%	28%	100%
CT - Third Generation Frame F	47%	100%	48%	100%	20%	100%
Nuclear	100%	100%	100%	100%	93%	100%
Sub-Critical Coal	93%	95%	85%	95%	25%	75%
Super Critical Coal	98%	100%	100%	100%	23%	86%

For the two CT technologies, less than 50 percent of the units in PJM received sufficient revenue from the energy market to recover avoidable costs in each of the three years analyzed, and RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for 2008 and 2009. For the combined cycle, capacity revenues were sufficient in 2008 to provide full recovery for all units, but in 2009, 7 percent of CCs showed less than full recovery of avoidable costs even with capacity revenues and in 2007 10 percent of CCs showed less than full recovery. However, these units show negative energy net revenues and typically operate during a high number of uneconomic hours independent of PJM dispatch, which suggests it likely that such units have a source of revenue outside of PJM markets. For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue.

There is a set of sub-critical coal units in 2008 and 2009 and a set of supercritical coal units in 2009 that did not recover avoidable costs even with capacity revenues. In addition, in 2009, 7 percent of nuclear units did not recover the class average nuclear avoidable cost rate from energy market revenues alone. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal and nuclear units relies more heavily on energy market revenues.

Energy market net revenues are a function of energy prices and operating costs, which are a function of the cost of inputs. In 2009, energy prices decreased more significantly than did the delivered price of coal, and, as a result, energy net revenues for coal units were down significantly from 2008. Figure 3-9 shows the frequency of coal units associated with several ranges of energy market net revenue for 2008 and 2009. In 2009, 27 percent of coal units received less than $10,000 per MW-year compared to 3 percent in 2008. In 2008, 70 percent of coal units received greater than $120,000 compared to only 4 percent in 2009. The change in energy market net revenue distributions between 2008 and 2009 is more pronounced for the sub-critical coal technology, which tends to be smaller and less efficient than the supercritical coal (Figure 3-10).

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Figure 3-9 Frequency of coal units within energy net revenue ranges as a percentage of total coal units for calendar years 2008 and 2009

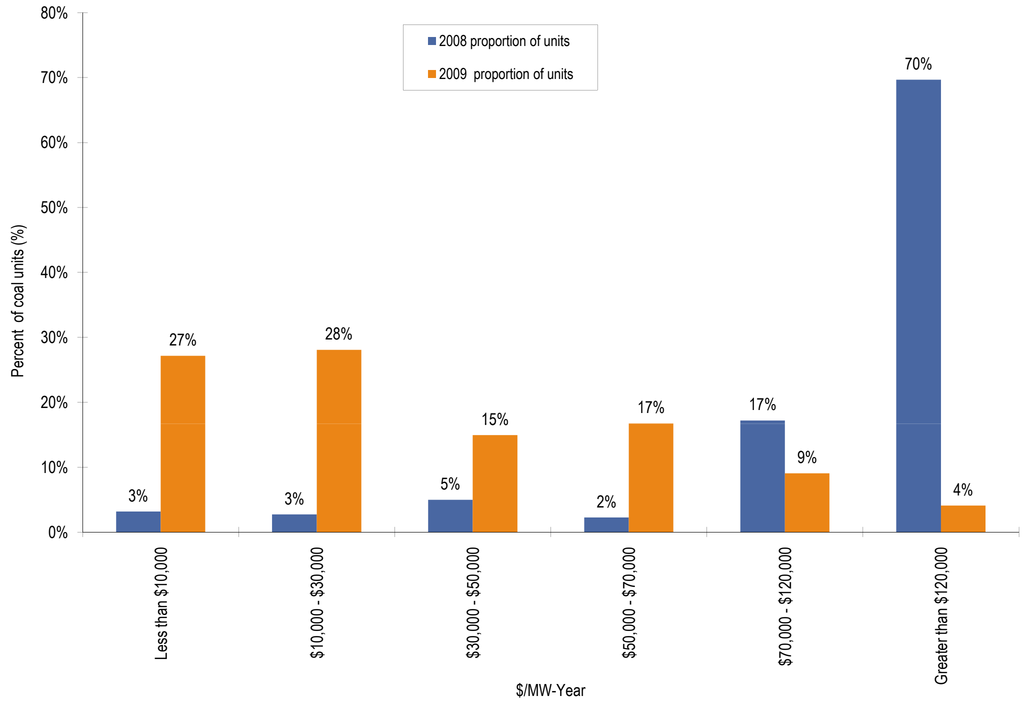

Figure 3-10 Frequency of sub-critical coal units within energy net revenue ranges as a percentage of total sub-critical coal units for calendar years 2008 and 2009

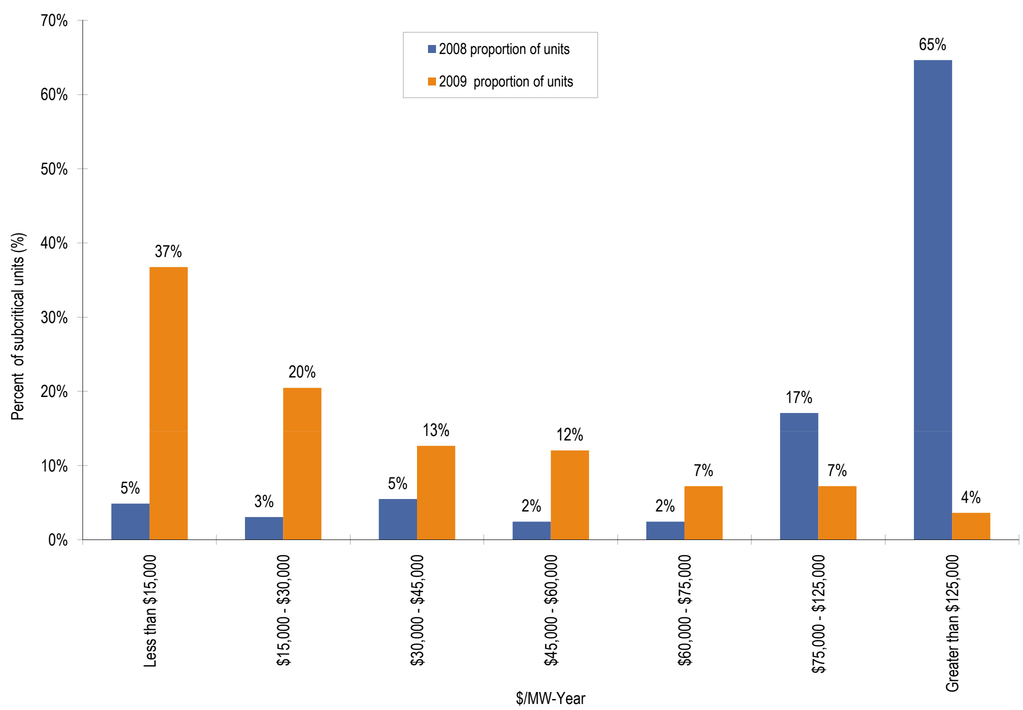

Table 3-34 shows characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues in 2009, by annual run hours. The total installed capacity associated with coal units that did not cover their avoidable costs in 2009 was 11,250 MW. The largest number of such coal units ran less than 1,000 hours in 2009. These units tended to be significantly smaller than other coal units with an average installed capacity of 73.1 MW and a maximum ICAP of 145 MW. In addition, they tended to incur higher costs of generation, showing a class average heat rate of approximately 10,500 and average operating costs of $54.58/MWh. These units act as mid-merit or even peaking units in the supply stack. They are called on during periods of high LMP and may continue to operate in unprofitable hours due to more severe operating constraints compared to the CT and CC technologies. MMU analysis indicates these units represent the majority of coal units that did not cover their avoidable costs in years 2007 and 2008 as well. There were 122 coal units in PJM in 2009 with capacity less than or equal to 200 MW. Of those units, 35 did not cover their avoidable costs and 52 were close to not covering their avoidable costs. Approximately 16 percent of coal units that did not cover their avoidable costs ran between 1,000 and 3,000 hours for the year, meaning that approximately 38 percent of such coal units ran less than 3,000 hours in 2009. Alternatively, 12 percent operated for more than 7,000 hours in 2009. These units tended to be more efficient and larger units.

Table 3-34 Profile of coal units not recovering avoidable costs from all PJM Market net revenues by hours of operation

Run hours	Proportion of unprofitable units	Average Heat Rate	Average ICAP	Maximum ICAP	Total MW	Average generating costs ($/MWh)
Less than 1,000	22%	10,496.8	73.1	145	804	$54.58
1,000-3,000	16%	9,957.9	185.3	440	1,482	$42.34
3,000-4,000	10%	10,387.8	306.6	500	1,533	$39.69
4,000 - 5,000	10%	10,057.5	211.6	319	1,058	$42.45
5,000 - 6,000	18%	10,070.0	380.4	1,300	3,424	$37.91
6,000 - 7,000	10%	9,702.4	163.2	230	816	$42.89
Greater than 7,000	14%	9,874.6	304.7	800	2,133	$39.10
Total/Average	100%	10,078.1	232.1	533	11,250	$42.71

The profitability of coal units is dependent on a number of factors, including dispatch strategy. It is the case in PJM that some coal units operated as "must-run" units, perhaps to avoid cycling, through periods in which they did not cover costs, independent of PJM dispatch, with the result that the negative net revenues offset positive net revenues earned during higher priced periods.

Location also affects the profitability of coal units. Approximately 85 percent of the coal units that did not cover avoidable costs cleared in the unconstrained RTO LDA for the period, representing the AEP, AP, ComEd, DAY, DLCO and Dominion Control Zones while only 15 percent were located in EMAAC or SWMAAC LDAs.[52] The zones associated with the RTO LDA receive lower capacity revenues and generally lower energy revenues compared to the EMAAC and SWMAAC LDA control zones.

Analysis of 2009 actual net revenues indicates that, for several technologies, there is a significant proportion of units not receiving sufficient net revenue in PJM Energy Markets to cover avoidable

52 A higher proportion of unprofitable units located within the unconstrained RTO Control zones does not alone suggest a cause and effect relationship as the majority of coal units in PJM are located in these control zones. The MMU refers to capacity market clearing prices, average LMPs and the economic dispatch scenario results to demonstrate the relationship between location and profitability of coal units.

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costs. For the CT technologies and the CC technology, capacity revenue from the RPM provides a sufficient supplement for units to fully recover avoidable costs. However, the coal plant technologies have higher avoidable costs and are more dependent on net revenues received in the energy market. In 2009, with lower load levels and, generally, lower price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues. If this result is expected to continue, the retirement of these plants would be an economically rational decision.

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2009, PJM installed capacity rose from 164,898.9 MW on January 1 to 167,326.4 MW on December 31, an increase of 2,427.5 MW or 1.5 percent, 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, 2009, PJM installed capacity was 164,898.9 MW.[53] (See Table 3-35) Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in an increase in installed capacity to 165,146.7 MW on May 31, 2009.[54]

Table 3-35 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2009

	1-Jan-09		31-May-09		1-Jun-09		31-Dec-09	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,064.7	40.7%	67,025.3	40.6%	68,159.0	40.7%	68,137.1	40.7%
Gas	48,333.9	29.3%	48,506.9	29.4%	48,979.3	29.2%	48,838.8	29.2%
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%	7,939.9	4.7%
Nuclear	30,478.0	18.5%	30,542.5	18.5%	30,701.5	18.3%	30,731.5	18.4%
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%	10,700.1	6.4%
Solid waste	664.7	0.4%	664.7	0.4%	672.1	0.4%	672.1	0.4%
Wind	166.4	0.1%	182.9	0.1%	297.8	0.2%	306.9	0.2%
Total	164,898.9	100.0%	165,146.7	100.0%	167,453.9	100.0%	167,326.4	100.0%

At the beginning of the new planning year on June 1, 2009, installed capacity increased by 2,307.2 MW to 167,453.9, a 1.4 percent increase in total PJM capacity over the May 31 level.

On December 31, 2009, PJM installed capacity was 167,326.4 MW.[55]

53 Percents shown in Table 3-35 and Table 3-36 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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

55 Wind-based resources accounted for 306.9 MW of installed capacity in PJM on December 31, 2009. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Energy Production by Fuel Source

In calendar year 2009, coal units provided 50.5 percent, nuclear units 36.0 percent, gas 9.7 percent, oil 0.2 percent, hydroelectric 2.0 percent, waste 0.8 percent and wind 0.8 percent of total generation. (See Table 3-36.)

Table 3-36 PJM generation (By fuel source (GWh)): Calendar year 2009

		GWh	Percent
Coal		349,818.2	50.5%
Nuclear		249,392.3	36.0%
Gas		67,218.9	9.7%
	Natural Gas	65,848.2	9.5%
	Landfill Gas	1,368.5	0.2%
	Biomass Gas	2.2	0.0%
Hydroelectric		14,123.0	2.0%
Waste		5,664.7	0.8%
	Solid Waste	4,147.0	0.6%
	Miscellaneous	1,517.7	0.2%
Wind		5,489.7	0.8%
Oil		1,568.1	0.2%
	Heavy Oil	1,383.7	0.2%
	Light Oil	162.9	0.0%
	Diesel	14.4	0.0%
	Kerosene	7.1	0.0%
	Jet Oil	0.0	0.0%
Solar		3.5	0.0%
Battery		0.3	0.0%
Total		693,278.7	100.0%

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2009, 76,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2009 and a year-end, installed capacity of 167,326 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000. (See Table 3-37).

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Table 3-37 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 to 2009[56]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516

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 V was active through January 31, 2010.

Capacity in generation request queues for the 10-year period beginning in 2009 and ending in 2018 decreased by 14,081 MW from 90,807 MW in 2008 to 76,725 MW in 2009, or 18 percent. (See Table 3-38.)[57] Queued capacity scheduled for service in 2009 decreased from 16,060 MW to 9,002 MW, or 78 percent. Queued capacity scheduled for service in 2010 decreased from 18,052 MW to 13,732 MW, or 31 percent. The 76,725 MW includes generation with scheduled in-service dates in 2009 and units still active in the queue with in-service dates scheduled before 2009, listed at nameplate capacity, although these units are not yet in service.

Table 3-38 Queue comparison (MW): Calendar years 2009 vs. 2008

	MW in the Queue 2008	MW in the Queue 2009	Year-to-Year Change (MW)	Year-to-Year Change
2009	16,060	9,002	(7,058)	(78.4%)
2010	18,052	13,732	(4,319)	(31.5%)
2011	17,253	15,873	(1,380)	(8.7%)
2012	15,527	11,053	(4,474)	(40.5%)
2013	7,920	6,350	(1,570)	(24.7%)
2014	11,965	13,439	1,474	11.0%
2015	2,436	3,091	655	21.2%
2016	0	950	950	100.0%
2017	0	1,640	1,640	100.0%
2018	1,594	1,594	0	0.0%
Total	90,807	76,725	(14,081)	(18.4%)

56 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

57 See the *2008 State of the Market Report for PJM* (March 11, 2009), pp. 159-160, for the queues in 2008.

Table 3-39 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[58]

Table 3-39 Capacity in PJM queues (MW): At December 31, 2009[59, 60]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,121	0	17,347	25,468
B Expired 31-Jan-99	0	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	100	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	100	2,416	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	319	186	3,978	4,482
N Expired 31-Jan-05	1,462	2,133	138	6,663	10,397
O Expired 31-Jul-05	1,978	1,048	570	3,978	7,574
P Expired 31-Jan-06	1,136	989	2,774	3,588	8,486
Q Expired 31-Jul-06	2,976	707	2,889	8,133	14,705
R Expired 31-Jan-07	7,169	566	790	14,192	22,716
S Expired 31-Jul-07	7,606	967	1,241	11,079	20,892
T Expired 31-Jan-08	16,484	164	351	11,469	28,468
U Expired 31-Jan-09	13,332	110	401	21,018	34,861
V Expires 31-Jan-10	14,337	0	56	980	15,372
Total	66,500	23,638	10,225	191,412	291,774

Data presented in Table 3-39 show that through 2009, 54 percent of total in-service capacity from all the queues was from Queues A and B and an additional 9 percent was from Queues C, D and E.[61] As of December 31, 2009, 27.8 percent of the capacity in Queues A and B has been put in service, and 8.1 percent of all queued capacity has been put in service.

The data presented in Table 3-40 show that for successful projects there is an average time of 729 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 520 days between entering a queue and exiting. For each status, there is substantial variability around the average results.

58 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.

59 The *2009 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.

60 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

61 The data for Queue V include projects through December 31, 2009.

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Table 3-40 Average project queue times: At December 31, 2009

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,056	641	0	3,165
In-Service	729	637	0	3,287
Suspended	2,294	865	890	4,172
Under Construction	1,312	845	0	4,370
Withdrawn	520	474	0	2,793

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.

Table 3-41 shows the RTEP projects under construction or active as of December 31, 2009, by unit type and control zone. Most of the steam projects (predominantly coal) (88.2 percent of the MW), most of the wind projects (96.3 percent of the MW) and most of the combined-cycle projects (60.1 percent of the MW) are outside the Eastern MAAC (EMAAC)[62] and Southwestern MAAC (SWMAAC)[63] locational deliverability areas (LDAs).[64] Of the total capacity additions, only 8,852 MW or 11.5 percent are projected to be in EMAAC; 4,728 MW or 6.2 percent are projected to be constructed in SWMAAC. Overall, 82.3 percent of capacity is being added outside the EMAAC and SWMAAC, and 74.1 percent of capacity is being added outside EMAAC, SWMAAC and MAAC.

Wind projects account for approximately 40,888 MW of capacity or 53 percent of the capacity in the queues and combined-cycle projects account for 14,836 MW of capacity or 19 percent of the capacity in the queues.[65] Wind projects account for 3,067 MW of capacity in MAAC LDAs, or 15.4 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,516 MW of capacity, or 17.1 percent.

62 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.
63 SWMAAC consists of the BGE and Pepco Control Zones.
64 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.
65 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent. Based on the derating of 40,888 MW of wind resources, the 76,725 MW currently active in the queues would be reduced to 41,153 MW.

Table 3-41 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2009[66]

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	0	767	4	0	0	201	665	1,066	0	2,702
AEP	0	1,035	594	2	100	84	25	3,726	10,662	73	16,302
AP	0	930	4	0	134	0	20	724	2,052	85	3,948
BGE	0	0	0	5	0	1,640	1	132	0	11	1,789
ComEd	0	1,680	1,044	98	0	392	0	1,366	23,728	0	28,308
DAY	0	0	10	2	112	0	22	12	1,149	0	1,306
DLCO	0	0	0	0	77	91	0	0	0	0	168
DPL	0	0	55	0	0	0	11	43	450	14	573
Dominion	0	3,521	181	25	30	1,944	45	405	230	475	6,855
JCPL	0	1,430	27	33	0	0	80	0	0	0	1,570
Met-Ed	0	1,745	2	26	0	24	30	10	0	675	2,512
PECO	0	1,200	136	6	0	500	1	18	0	575	2,436
PENELEC	0	0	65	18	32	0	0	50	1,372	0	1,537
Pepco	20	2,670	249	0	0	0	0	0	0	0	2,939
PPL	0	0	137	3	143	1,600	26	116	179	5	2,208
PSEG	0	625	767	0	0	0	113	0	0	65	1,570
Total	20	14,836	4,038	223	627	6,275	575	7,266	40,888	1,977	76,725

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-42 shows that in the EMAAC LDA, gas burning unit types account for 56.5 percent of the capacity additions. Steam additions (coal) account for about 8.1 percent of the MW and wind projects account for 17.1 percent of the MW in the queue for the EMAAC LDA. Nuclear and gas capacity comprise 96.4 percent of the MW capacity additions in the SWMAAC LDA. It should be noted that the wind capacity in this section is reported at nameplate capacity and not reduced to 13 percent of nameplate.

Table 3-42 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2009[67]

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	0	3,255	1,752	43	0	500	407	726	1,516	654	8,852
SWMAAC	20	2,670	249	5	0	1,640	1	132	0	11	4,728
WMAAC	0	1,745	204	48	175	1,624	56	176	1,551	680	6,257
RTO	0	7,166	1,833	127	453	2,511	112	6,233	37,821	633	56,888
Total	20	14,836	4,038	223	627	6,275	575	7,266	40,888	1,977	76,725

66 In this section, unit type "Unknown" is referred to for units that the RTEP has not yet identified.
67 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

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Table 3-43 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 3-41 and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Table 3-43 Existing PJM capacity 2009[68] (By zone and unit type (MW))

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	641	23	0	0	1,274	0	8	1,945
AEP	0	4,355	3,627	57	1,001	2,106	21,255	0	802	33,204
AP	0	1,129	1,140	36	108	0	7,974	0	245	10,632
BGE	0	0	862	7	0	1,735	3,039	0	0	5,643
ComEd	0	1,836	7,217	108	0	10,336	7,094	0	1,762	28,352
DAY	0	0	1,377	53	0	0	3,551	0	0	4,981
DLCO	0	101	188	0	6	1,741	1,259	0	0	3,295
DPL	0	364	2,487	95	0	0	2,016	0	0	4,962
Dominion	0	3,216	3,786	162	3,325	3,425	8,479	0	0	22,393
External	0	974	1,890	0	0	439	9,314	0	185	12,802
JCPL	0	1,196	1,430	25	400	615	318	0	0	3,983
Met-Ed	0	2,000	407	24	20	786	890	0	0	4,127
PECO	1	2,540	833	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	0	287	47	521	0	6,830	0	447	8,131
Pepco	0	0	1,571	12	0	0	4,707	0	0	6,290
PPL	0	960	1,352	63	571	2,275	5,530	0	217	10,968
PSEG	0	2,921	2,852	0	5	3,553	2,531	0	0	11,862
Total	1	21,592	31,945	720	7,599	31,499	88,188	3	3,665	185,212

Table 3-44 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 47.6 percent of all current MW, steam units 40 years of age and older comprise 84.6 percent of all MW 40 years of age and older and nearly 92.4 percent of such MW if hydroelectric is excluded from the total. Approximately 7,509 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC.

68 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

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Table 3-44 PJM capacity age (MW)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,357	18,851	396	10	0	1,357	3	3,665	41,639
10 to 20	0	3,976	4,767	120	49	0	6,133	0	0	15,044
20 to 30	0	158	437	38	3,207	15,981	9,999	0	0	29,819
30 to 40	0	101	5,296	39	451	14,903	31,316	0	0	52,106
40 to 50	0	0	2,594	123	2,470	615	24,269	0	0	30,071
50 to 60	0	0	0	4	348	0	13,610	0	0	13,962
60 to 70	0	0	0	0	32	0	1,357	0	0	1,389
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	32	0	0	0	0	32
Total	1	21,592	31,945	720	7,599	31,499	88,188	3	3,665	185,212

Table 3-45 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generators. In 2018, CC and CT generators would account for 52.6 percent of EMAAC generation, an increase of 8.3 percentage points from 2009 levels. Accounting for the fact that about 940 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 47 percent to about 52 percent. The proportion of gas-fired capacity in EMAAC would increase to 54.4 percent if the 87 percent reduction for wind capacity is taken into account for EMAAC, meaning that the effective capacity additions are 7,533 MW.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 61.6 percent of all new capability in EMAAC and 73.5 percent when the 87 percent reduction for wind capability is included.

There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent nearly 100 percent of all new capability in the SWMAAC. In 2018 this would mean that CC and CT generators would comprise 37.4 percent of total capability in SWMAAC.

In RTO[69] zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation. In these zones, 92.1 percent of all generation 40 years or older is steam (mostly coal).With the retirement of these units, in 2018, this would mean that wind farms would comprise 28.0 percent of total capacity in RTO zones.

69 RTO zones consist of the AEP, AP, ComEd, DAY, DLCO, and Dominion Control Zones.

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Table 3-45 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[70]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	0	1	0.0%
	Combined Cycle	0	0.0%	7,021	20.4%	3,255	10,276	28.0%
	Combustion Turbine	960	12.1%	8,242	24.0%	1,752	9,034	24.6%
	Diesel	49	0.6%	150	0.4%	43	144	0.4%
	Hydroelectric	2,042	25.8%	2,047	6.0%	0	2,047	5.6%
	Nuclear	615	7.8%	8,656	25.2%	500	8,541	23.3%
	Solar	0	0.0%	3	0.0%	407	410	1.1%
	Steam	4,243	53.6%	8,268	24.0%	726	4,750	12.9%
	Wind	0	0.0%	8	0.0%	1,516	1,524	4.1%
	Unknown	0	0.0%	0	0.0%	654	654	1.8%
	EMAAC Total	7,909	100.0%	34,395	100.0%	8,852	36,727	100.0%
SWMAAC	Battery	0	0.0%	0	0.0%	20	20	0.2%
	Combined Cycle	0	0.0%	0	0.0%	2,670	2,670	20.8%
	Combustion Turbine	556	14.5%	2,433	20.4%	249	2,126	16.6%
	Diesel	0	0.0%	19	0.2%	5	24	0.2%
	Nuclear	0	0.0%	1,735	14.5%	1,640	3,375	26.3%
	Solar	0	0.0%	0	0.0%	1	1	0.0%
	Steam	3,266	85.5%	7,746	64.9%	132	4,612	36.0%
	Unknown	0	0.0%	0	0.0%	11	11	0.1%
	SWMAAC Total	3,822	100.0%	11,932	100.0%	4,728	12,819	100.0%
	Combined Cycle	0	0.0%	2,960	12.7%	1,745	4,705	21.0%
WMAAC	Combustion Turbine	296	4.3%	2,046	8.8%	204	1,954	8.7%
	Diesel	35	0.5%	135	0.6%	48	147	0.7%
	Hydroelectric	444	6.5%	1,112	4.8%	175	1,286	5.7%
	Nuclear	0	0.0%	3,061	13.2%	1,624	4,685	20.9%
	Solar	0	0.0%	0	0.0%	56	56	0.2%
	Steam	6,052	88.6%	13,249	57.0%	176	7,373	32.9%
	Wind	0	0.0%	663	2.9%	1,551	2,214	9.9%
	Unknown	0	0.0%	0	0.0%	680	680	3.0%
	WMAAC Total	6,827	100.0%	23,226	100.0%	6,257	22,420	100.0%
RTO	Combined Cycle	0	0.0%	11,611	10.0%	7,166	18,776	12.9%
	Combustion Turbine	782	2.8%	19,225	16.6%	1,833	20,276	13.9%
	Diesel	43	0.2%	416	0.4%	127	500	0.3%
	Hydroelectric	1,396	5.0%	4,440	3.8%	453	4,893	3.4%
	Nuclear	0	0.0%	18,047	15.6%	2,511	20,558	14.1%
	Solar	0	0.0%	0	0.0%	112	112	0.1%
	Steam	25,824	92.1%	58,926	50.9%	6,233	39,335	27.0%
	Wind	0	0.0%	2,994	2.6%	37,821	40,815	28.0%
	Unknown	0	0.0%	0	0.0%	633	633	0.4%
	RTO Total	28,045	100.0%	115,658	100.0%	56,888	145,897	100.0%
All Areas	Total	46,602		185,212		76,725	217,863	

70 Percents shown in Table 3-44 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Characteristics of Wind Units

Table 3-46 shows the capacity factor of wind units in PJM. During calendar year 2009, the capacity factor of wind units in PJM was 29.1 percent. Wind units that were capacity resources had a capacity factor of 30.6 percent and an installed capacity of 2,393 MW. Wind units that were classified as energy only had a capacity factor of 22.7 percent and an installed capacity of 1,086 MW. Much of this wind capacity does not appear in the RPM market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.

Table 3-46 Capacity factor of wind units in PJM, Calendar year 2009[71]

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	22.7%	75,345	1,086
Capacity Resource	30.6%	190,502	2,393
All Units	29.1%	265,847	3,665

Beginning June 1, 2009, units were able to submit negative price offers. Table 3-47 presents data on negative offers by wind units. Wind units were the only unit types to make negative offers. On average, 170.4 MW of wind is offered daily at a negative price. Wind units with negative offers were marginal in 102 separate 5-minute intervals, or 0.10 percent of all intervals. On average, 1,197.2 MW of wind is offered daily. Overall, wind units were marginal in 671 separate 5-minute intervals, or .65 percent of all intervals.

Table 3-47 Wind resources in real time offering at a negative price in PJM, June through December 2009

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	170.4	102	0.10%
All Wind	1,197.2	671	0.65%

Wind output differs from month to month, based on weather conditions. Figure 3-11 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in the months of April, October, November and December, and lowest in June, July, August and September. The highest average hour, 1399.5 MW, occurred in December, and the lowest average hour, 185.8 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

71 The corresponding table in the *2009 Quarterly State of the Market Report for PJM: January through June*, reversed the labels for energy only resources and capacity resources data.

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Figure 3-11 Average hourly real-time generation of wind units in PJM, Calendar year 2009

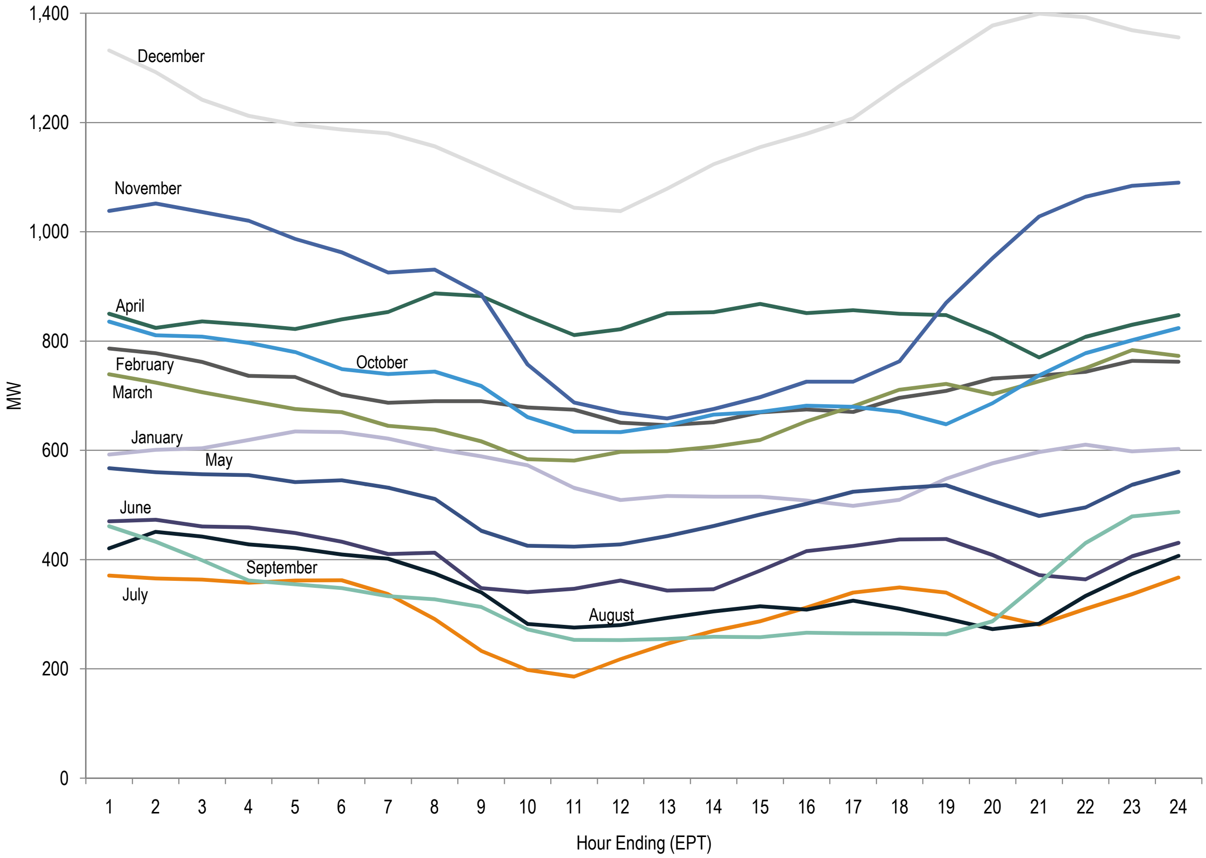

Table 3-48 shows the generation and capacity factor of wind units in each month of 2009. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 45.3 percent in February, and the lowest capacity factor was 14.9 percent in July, a difference of 30.4 percentage points. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came online throughout 2009, and are included in this analysis as they were added.

Table 3-48 Capacity factor of wind units in PJM by month, Calendar year 2009[72]

Month	Generation (MWh)	Capacity Factor
January	424,885.1	39.6%
February	476,702.8	45.3%
March	501,320.6	35.0%
April	604,480.0	40.6%
May	376,904.6	24.5%
June	291,886.9	19.6%
July	228,850.7	14.9%
August	258,708.4	16.8%
September	239,457.9	16.1%
October	539,353.2	31.5%
November	638,556.4	32.0%
December	908,613.8	38.4%
Annual	5,489,720.3	29.1%

Table 3-49 shows the seasonal capacity factor of wind units in PJM, as well as the seasonal average hourly wind generation and seasonal average hourly load on peak and off peak periods. The on peak winter capacity factor was 39.0 percent while the on peak summer capacity factor was 13.6 percent. The off peak winter capacity factor was 0.4 percentage points lower than during the on peak period, while the off peak summer capacity factor was 5.2 percentage points higher than during the on peak period.

Table 3-49 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, Calendar year 2009

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	39.0%	31.6%	13.6%	25.0%	27.1%
	Average Wind Generation	810.0	638.7	282.0	592.5	577.5
	Average Load	90,361.8	77,109.7	91,520.8	77,362.0	84,148.4
Off-Peak	Capacity Factor	38.6%	31.8%	18.8%	27.6%	29.1%
	Average Wind Generation	797.6	642.3	388.8	657.9	622.0
	Average Load	78,247.0	63,339.0	70,548.1	62,493.6	68,588.6

Wind output differs from month to month, based on weather conditions, and is projected by generation owners in the Day-Ahead Market. Figure 3-12 shows the average hourly day-ahead time generation of wind units in PJM, by month.

72 Capacity factor shown in Table 3-48 is based on all hours in 2009.

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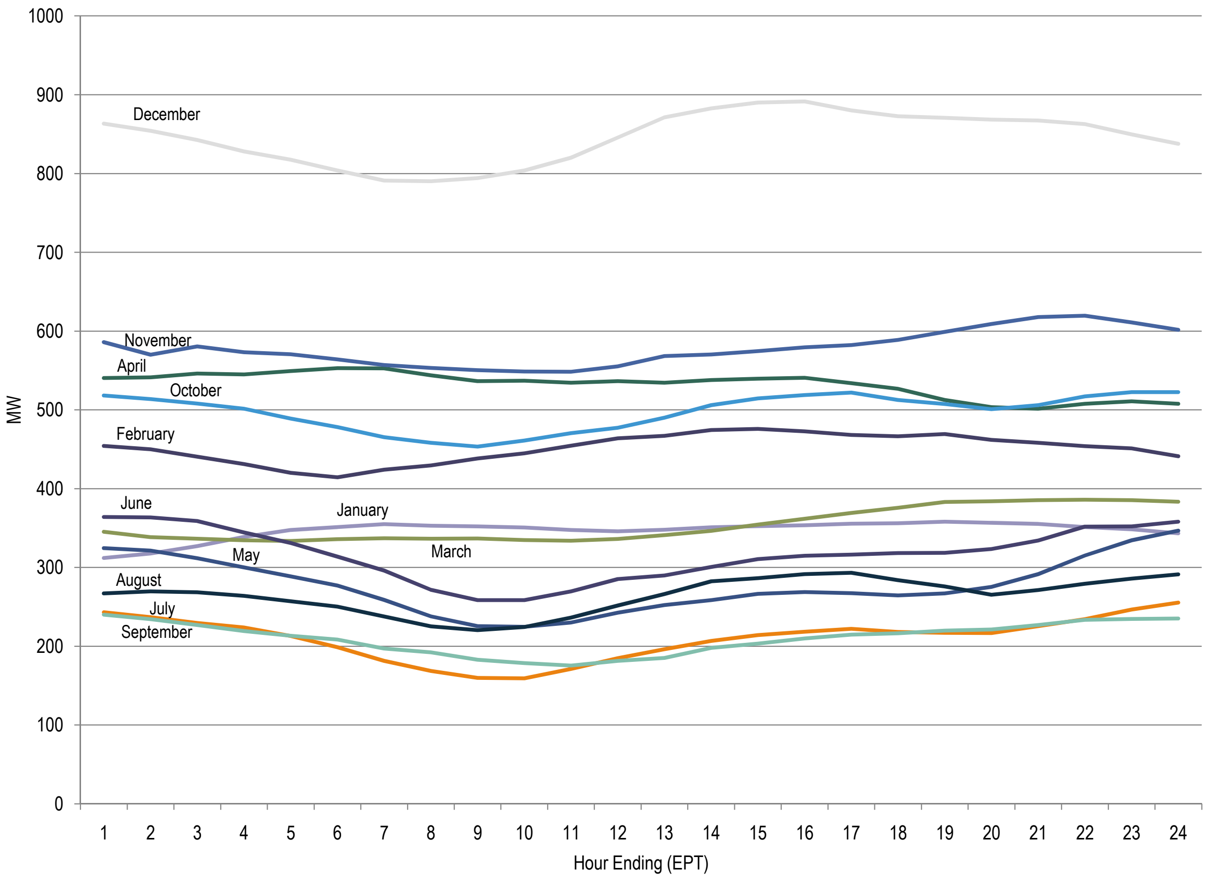
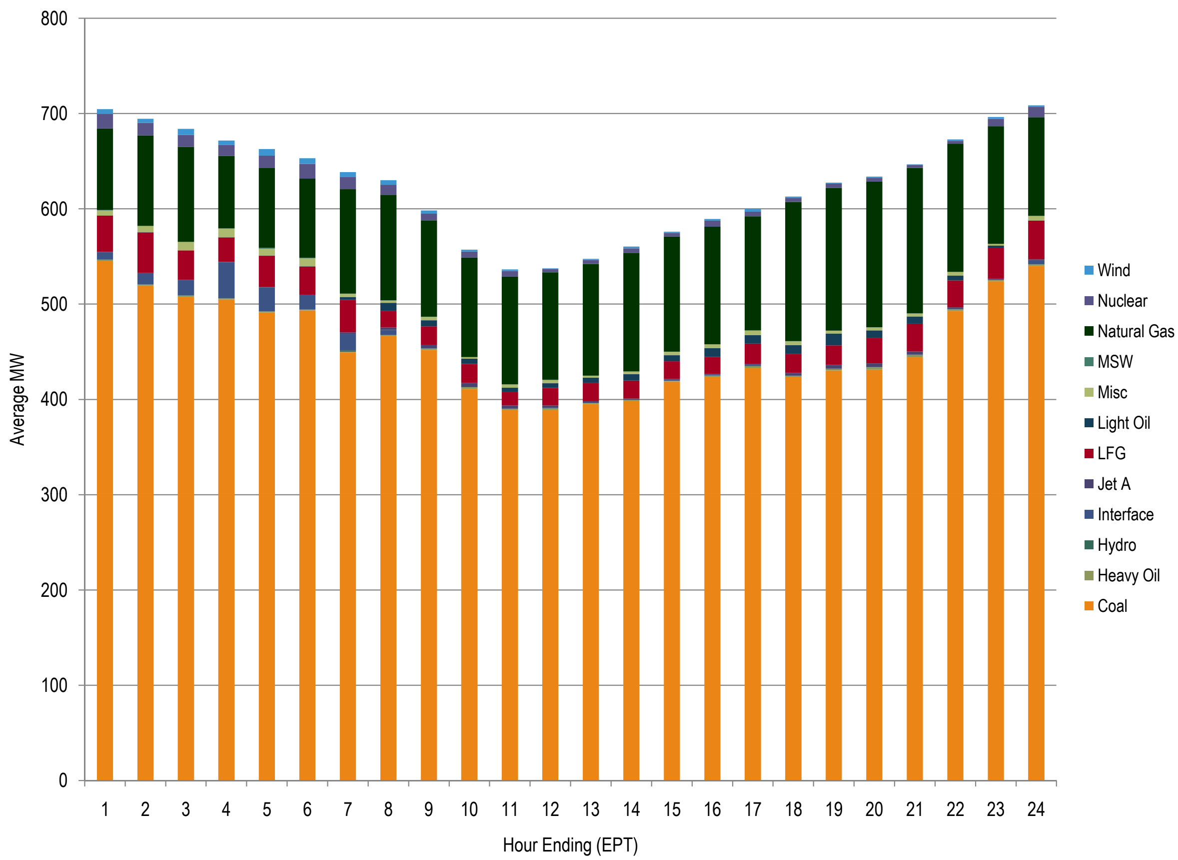
Figure 3-12 Average hourly day-ahead generation of wind units in PJM, Calendar year 2009



Output from wind turbines displaces output from other generation types. This displacement will directly affect the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. Of interest is the type of marginal generation that may be displaced on an average hourly basis by wind turbine output. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 3-13 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2009. This provides, on an hourly average basis, potentially displaced marginal unit MWs by fuel type in 2009. Wind output varies daily, and on average is about 165 MW lower from peak output (11:00 PM EPT) to lowest output (10:00 AM EPT).

Figure 3-13 Marginal fuel at time of wind generation in PJM, Calendar year 2009



Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. 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.[73] 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 may be the result of appropriate scarcity pricing rather than market power.

Scarcity Revenues: The Need for Administrative Mechanisms

While higher prices are expected during scarcity without a specific market mechanism, a wholesale energy market will not consistently result in adequate revenues in the absence of a carefully

73 See *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2008 and 2009 ."

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designed and comprehensive approach to scarcity pricing. This 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 that require wholesale power markets to carry excess capacity means that scarcity conditions in the Energy Market occur with reduced frequency. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Resources that do not run for energy, but are needed for reliability, are not supported through an energy only market.

Further, when available capacity is not sufficient to maintain reserves, system operators have to turn to non-market solutions to maintain reliable service, including voltage reductions, load dumps, emergency energy purchases, emergency load response and other measures. All of these administrative control actions are designed to preserve the level of reserves needed to maintain system reliability. These administrative emergency actions produce counter intuitive price effects; they reduce prices during scarcity conditions.

For these reasons, the energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This provides the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and its administrative scarcity pricing mechanism in the energy market. Scarcity revenues to generation owners can come from a combination of energy and capacity markets or they can come entirely from capacity markets.

PJM's current administrative scarcity pricing mechanism is designed to recognize real time scarcity in the energy market and to increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit. 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.

Scarcity Mechanisms

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. If the scarcity revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, energy market design should permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Energy market scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent and verifiable triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power.

Energy market scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design, as long as the market rules are designed to ensure that energy market derived scarcity revenues directly offset RPM derived scarcity revenues to prevent double collection of scarcity revenues. This offset must reflect the actual scarcity revenues. The absence of such a mechanism will result in an over collection of scarcity revenues.

The most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, would be to ensure that capacity resources do not receive scarcity revenues from the energy market.

With a settlement process that appropriately offsets scarcity revenues from the energy market against scarcity revenues from the capacity 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. If these design elements are retained, administrative scarcity pricing in the energy market can be a key component in overall market design.

Current Issues with Scarcity Implementation

PJM's current administrative scarcity pricing mechanism is designed to recognize real time scarcity in the energy market and increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit. These emergency actions include emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events. [74] The use of any of these measures to maintain system integrity in predefined scarcity pricing regions is an indication that the affected area of the system is in a state of scarcity. 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 an energy market scarcity pricing mechanism is needed, and PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, the MMU's review of market results leads to our recommendation that PJM's scarcity pricing mechanism be reviewed and modified. PJM's stakeholders are discussing ways to improve PJM's current energy market scarcity pricing mechanism.

Proposed Scarcity Pricing Approach

It is the MMU's position that more flexible and locational scarcity signals should be implemented via reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch. Conceptually, incorporating reserve penalty factor curves into the security constrained dispatch

74 See PJM. "Open Access Transmission Tariff (OATT)," Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.01 (Effective May 17, 2008).

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internalizes the value of maintaining resources needed for reliability in the centralized dispatch market solution, prior to going into scarcity conditions.

The penalty factors associated with the reserve target constraints would force system dispatch energy prices to reflect the severity level of the scarcity event as the system was redispatched to maintain the reserve requirements. If the reserve requirements were violated, energy prices at the marginal unit buses would be set to a predefined price target. The MMU recommends predefined energy price targets that are consistent with PJM's current offer caps in both the Day Ahead and Real Time energy markets. A price target set at $1,000 at the marginal unit buses in the area with a reserve shortage would provide a clear scarcity signal that is consistent with scarcity, consistent with economic dispatch, consistent with locational pricing, consistent with competitive market outcomes and consistent with PJM's current market design.

Under the MMU's price target approach, the prices for reserves would continue to be determined in forward looking (hour ahead) markets similar to those currently used for regulation and Tier 2 synchronized reserve resources, with real time true up of the opportunity costs payments to generators made at settlement. Resources dispatched for reserves in the hour ahead market during scarcity would clear based on their offers and their opportunity costs. The resulting clearing price for reserves would fully reflect the energy market scarcity price. Resources dispatched within the hour for reserves would be paid their real time opportunity costs for providing reserves.

There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. Given the significant nature of the changes to the PJM markets that is required in order to implement any significant change to scarcity pricing, a step by step approach is warranted. If scarcity pricing is implemented successfully and the markets gain experience with it, higher offer caps should be considered. However, the assertion that much higher prices are required now in order to incent the participation of additional resources is unsupported, particularly given the absence of metering adequate to facilitate a response by the demand side of the market. In addition, the PJM RPM market is designed to achieve the target reliability levels with the resources acquired through the capacity market.

Transparent and Appropriate Scarcity Pricing Triggers

To work properly in recognizing and internalizing resource scarcity, the reserve constraint requirement mechanism must make use of clearly defined reserve targets and accurate measurement of the resources that are available to meet those requirements. These reserve targets must match defined reserve requirements. The objective should be to create a system that recognizes scarcity in needed reserves; a system that redispatches to maintain needed reserves and a system that provides market signals that are consistent with this redispatch and with any failure to maintain needed reserves. The driver for the determination of scarcity and its reflection in price should be based directly on the level of available 10 minute synchronized reserves relative to the relevant reserve requirement and the progressive use of emergency measures.

PJM's primary reserve requirement targets are based on engineering requirements and system studies that have defined minimum requirements to maintain system integrity. PJM's system is currently manually dispatched to maintain primary reserves. Explicitly modeling these requirements as constraints in the dispatch will permit the system to optimize the dispatch to maintain appropriate and efficient levels of energy and reserves, and to reflect this optimization in the marginal prices on the system. This approach does not preclude the use of forward looking market mechanisms that clear, price and commit reserves prior to the operational hour. In fact the absence of some form of precommitment process for reserves, given operational constraints on resources, will cause suboptimal results in market outcomes.

Accurate measurement of available resources is an essential element of a reserve requirement based scarcity pricing mechanism. Any mechanism that attempts to internalize the dispatch of reserves will only be as good as the measurement of those reserves. Without accurate measurement of available reserves, any mechanism designed to dispatch the system to maintain reserves will be compromised in both efficiency and effectiveness. Based on the direction of the error at any given time, the system could be buying too much reserve or too little, the system could be in a state of unrecognized scarcity or unrecognized surplus. To be effective, operators will need accurate data on unit availability and capabilities at any given moment, including better data on ramp rates and ambient temperature adjustments. PJM does not currently have accurate real time measurements of available operating reserves that are required for an improved approach to scarcity pricing. PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism.

The reserve requirement penalty factors should be designed to force the system to redispatch resources to maintain system reliability. The objective should be to internalize the cost of maintaining reserve levels needed to maintain reliability, and then sending a clear energy price signal when actual reserve requirements cannot be met. Adding a reserve requirement in addition to what is needed to maintain reliability would be superfluous and wasteful. Requiring, for example, that the system maintain some level of previously undefined level of 30 minute reserves would introduce unnecessary price signals not required for reliable operation. The same is true for using 10 minute non-synchronized reserves as a trigger for scarcity. If maintaining sufficient 10 minute synchronized reserves will maintain reliable operation, there is no reason to use a higher operating reserve threshold.

Mitigating Market Power and Within Hour Reserve Resources

Under the MMU reserve penalty factor curve approach, local market power mitigation in the energy market would remain in force regardless of scarcity conditions. Rather than depending on market power to increase prices during scarcity, the administrative scarcity pricing mechanism results in appropriate prices during a reserve shortage event. This approach eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events.

To avoid market power issues and to provide the correct market signals, the provision of within hour reserves must be based on unit characteristics included in a participant's energy offers, not on the basis of separate offers to provide reserves. Currently market participants provide within-hour reserves on the basis of their energy offer operating parameters including the start time of the unit, the ramp capability of the unit and the total number of MW available from the unit.[75] These parameters also play a direct role in determining how much energy the unit will sell into the PJM market at any given moment in time. As there are no incremental costs for a resource to provide

75 Within hour reserves in this context does not refer to reserves that currently clear in the hour ahead Tier 2 market, which do provide offers to participate.

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reserves, rather than energy, the within hour reserve availability bid should be zero because the resource is already dispatched and committed to serve energy on the basis of the same set of parameters which determine its reserve capabilities. Allowing for separate energy and within hour reserve offers would force an inefficient allocation of the unit's capability between reserves and energy since this would artificially create inconsistent parameters sets, one for energy and one for reserves, which distort the direct substitutability of unit capacity deployed as either reserves or energy within the hour. Allowing separate offers would create opportunities to withhold reserves.

Scarcity Revenues: The Offset

In the overall market design, scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The approach to scarcity must reflect the fact that revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to include a scarcity pricing mechanism in the energy market because it provides additional direct, market-based incentives to load and generation at the margin, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues. Scarcity revenues are those revenues directly attributable to scarcity price adder contributions to the marginal unit LMPs during a reserve shortage.

The most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, would be to ensure that capacity resources do not receive scarcity revenues. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market. Under this approach generators would retain scarcity revenues from the energy market that exceed, on a cumulative annual, the RPM revenues for the delivery year. For example, if a capacity resource were earning $100 per MW-day from RPM and there were three scarcity event days in the year that generated a cumulative equivalent of $120 per MW-day of scarcity revenues, the capacity resource would collect $20 per MW-day from the cumulative scarcity events over and above its $100 per MW-day capacity market based scarcity payment. This method would prevent double collection of scarcity revenues while recognizing the potential for inadequate scarcity revenues from the RPM market during a particular delivery year.

Accounting for Emergency Procedures and Emergency Actions

The reserve penalty factor curve methodology, regardless of price target, also needs a mechanism to offset the effect of unpriced, non-market administrative measures used during scarcity situations, such as voltage reductions. The offset would increase the reserve requirement by the amount of effective energy provided by the emergency step so as to maintain a market signal consistent with the actual level of scarcity, which is the level of scarcity that would persist in the absence of the administrative action.

A well designed offset will prevent prices from falling as a result of emergency actions during a period of scarcity. In order to implement this, PJM will have to be able to accurately measure

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the MW impact of the emergency steps. This reserve MW offset mechanism should be used to maintain consistent pricing only for unpriced emergency actions. It should not be applied to emergency resources that have been purchased and have a recognized market value, namely maximum emergency generation and emergency load response. Maximum emergency generation and emergency load resources need to be counted towards reserve targets when available under emergency conditions, as these resources have recognized value in the capacity market and provide their energy, or reduction in demand, at a specified price under emergency conditions.

Maximum emergency and emergency load response resources must be counted as energy, if providing energy (or reduced demand), and must be counted as reserves if capable of providing reserves. Ensuring that generation capacity and demand side capacity, either economic or emergency, is counted as an available resource eliminates the incentive to move capacity from economic to emergency designation during emergency conditions and thereby force scarcity conditions and higher prices.

Any scarcity pricing mechanism should also include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.

Operating Reserve

Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of total operating reserve credits and corresponding charges decreased in 2009 by 24.1 percent compared to 2008, to a total of $325,842,346. This was primarily the result of a large decrease in the amount of balancing operating reserve credits. The decrease in operating reserve credits is the result of a number of factors including the decrease in load, the decline in fuel costs and the related decreases in generator offer prices, LMP and congestion in 2009.

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

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manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

New rules governing the payment of operating reserve credits and the allocation of operating reserve charges became effective on December 1, 2008. The new Operating Reserve Construct will be referred to as the new rules and the prior Operating Reserve Construct will be referred to as the old rules.

The following operating reserve business rule changes were made effective on December 1, 2008:

- **Segmented Make Whole Payments.** Resources will be made whole separately for the blocks of hours they operate at PJM direction. There will a maximum of two segments per calendar day, per unit. The first segment will be the greater of the day-ahead schedule or minimum run time (minimum downtime for demand resources); the second segment will be the remainder of the unit run for that calendar day.[76]

- **Parameter Limited Schedules.** When a unit needed for operating reserve has local market power as defined by the three pivotal supplier test or when PJM declares a maximum generation emergency alert, units will be required to use operating parameters consistent with competitive offers. These parameters are defined by unit characteristics and included in a matrix developed by the MMU and included in the PJM OA.[77] PJM also developed business rules approved November 15, 2007, by the Members Committee that, among other things, established a process to evaluate unit-specific exceptions to the values included in the matrix.[78]

- **Generator Deviations.** PJM will use ramp-limited desired MW to determine generator deviations from desired dispatch. Pool-scheduled generators deemed to be following dispatch will not be assessed balancing operating reserve deviations.[79]

- **Netting Generator Deviations.** Generators that deviate from real-time dispatch will be able to offset deviations by using another generator at the same bus. Both generators must be owned or offered by a single PJM market participant and must have identical electrical impacts on the transmission system.[80]

- **Locational Netting of Deviation Calculations.** Demand deviations will be calculated by comparing all day-ahead demand transactions within a single transmission zone, hub, or interface against the real-time demand transactions within that same transmission zone, hub, or interface. Supply deviations will be calculated by comparing all day-ahead transactions within a single transmission zone, hub, or interface against the real-time transactions within that same transmission zone, hub, or interface. Generator deviations will be calculated on a unit-specific basis, except for the netting provisions. Deviations that occur within a single zone will be associated with a region and will be charged the regional balancing operating reserve rate.[81]

76 PJM "Operating Reserve Revised Business Rules v6": *Segmented Make Whole Payments* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
77 PJM OA Schedule 1 § 6.6(c).
78 PJM "Operating Reserve Revised Business Rules v6": *Minimum Generator Operating Parameters – Parameter Limited Schedule* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
79 PJM "Operating Reserve Revised Business Rules v6": *Ramp-limited RT Desired MW to determine deviations* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
80 PJM "Operating Reserve Revised Business Rules v6": *Supplier Netting* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
81 PJM "Operating Reserve Revised Business Rules v6": *Netting Deviation Calculations* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

- **Balancing Operating Reserve Charge Allocation.** PJM will determine whether operating reserve credits are earned for reasons associated with reliability or with real-time deviations from day-ahead results. PJM will make this determination in both the reliability analysis stage and the real-time stage. Reliability related credits are recovered from charges to real-time load plus exports and deviations related credits are recovered from charges to deviations.[82]

- **Regional Balancing Operating Reserve Charge Allocation.** PJM will identify operating reserves credits that are associated with controlling local constraints, identified as constraints on transmission lines rated at less than or equal to 345kv. Local constraints will be identified as in the Western or the Eastern Region. The resultant operating reserve credits will be allocated as charges to all real-time deviations and real time load within a region, resulting in a Regional Adder rate for Reliability and a Regional Adder rate for Deviations.[83]

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 3-50 shows the categories of credits and charges and their relationship. The bottom half of this table shows how credits are allocated under the new operating reserve construct. Table 3-51 shows the different types of deviations.

Table 3-50 Operating reserve credits and charges

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

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

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

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Table 3-51 Operating reserve deviations

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

Day-Ahead Credits and Charges

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

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-54 shows monthly day-ahead operating reserve charges for calendar years 2008 and 2009.

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.[84] The rules governing these credits and associated charges were not modified in the new rules.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-54 shows monthly synchronous condensing charges for calendar years 2008 and 2009.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, and real-time import transaction credits. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced at

84 PJM. "Manual 28: Operating Agreement Accounting," Revision 42 (July 31, 2009).

PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to cancelled pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

Table 3-52 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 3-52 shows the allocation process for balancing operating reserves. Credits are assigned to units during two periods, the reliability analysis and the Real-Time Market. During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations and to meet real-time load. Conservative operations means that units are committed due to conditions that warrant conservative actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are credited as reliability credits and are allocated to real-time load plus exports. Units are committed to operate in real-time to augment the physical units committed in the Day-Ahead Market in order to meet the forecasted real-time load plus the operating reserve requirement. The resultant credits are credited as deviation credits and are allocated to supply, demand, and generator deviations.

In the Real-Time Market, credits are also allocated for reliability or to meet load. Credits are paid to units that are called on by PJM and in which the LMP is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are credited as Reliability Credits and are allocated to real-time load plus exports. Balancing operating reserve credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour will be allocated as deviation credits. These are allocated to real-time supply, demand, and generator deviations from day-ahead schedules.

Credits are allocated regionally based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500kV or 765kV are assigned to RTO credits while credits associated with all other voltages are assigned to regional credits.

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Credit and Charge Results

Overall Results

Table 3-53 shows total operating reserve credits from 1999 through 2009.[85,86] Total operating reserve credits decreased by 24.1 percent in 2009 from 2008. Table 3-53 shows the ratio of total operating reserve credits to the total value of PJM billings.[87] This ratio decreased from 1.3 percent in 2008 to 1.2 percent in 2009. With the exception of 2004, this ratio has decreased every year from 1999 through 2009.

Table 3-53 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2009

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341 2	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.1201	42.3%	1.1100*	(47.5%)

Table 3-53 shows the average operating reserve credits per MWh (or the charge rate) for each full year since the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate increased $0.0357 per MWh or 42.3 percent from $0.0844 per MWh in 2008 to $0.1201 per MWh in 2009. The balancing operating reserve rate decreased $1.0032 per MWh, or 47.5 percent, from $2.1132 per MWh in 2008 to $1.1100 per MWh in 2009. The balancing rate of $1.1100 per MWh for 2009 is a representation of what the rate would have been if calculated under the old operating construct rules. This was derived by taking all regional reliability and deviation credits for the day and dividing by total PJM supply, demand, and generator deviations. The rates shown in the table are the averages of the daily rates across the year.

85 Table 3-53 includes all categories of credits as defined in Table 3-50 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on January 19, 2010.

86 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.

87 See the *2009 State of the Market Report for PJM*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2009," for a description of the value of total annual PJM billings during the period indicated.

Total operating reserve charges in 2009 were $325,842,346, down from the total of $429,253,839 in 2008. Table 3-54 compares monthly operating reserve charges by category for calendar years 2008 and 2009. The overall decrease of 24.1 percent in 2009 is comprised of a 36.4 percent increase in day-ahead operating reserve charges, a 56.6 percent decrease in synchronous condensing charges and a 35.5 percent decrease in balancing operating reserve charges. The share of day-ahead operating reserve charges to total operating reserve charges increased by 12.9 percentage points to 29.1 percent, the share of synchronous condensing charges decreased 0.5 percentage points to 0.8 percent, and the share of balancing charges decreased 12.3 percentage points to 70.1 percent.

Table 3-54 Monthly operating reserve charges: Calendar years 2008 and 2009

	2008 Charges				2009 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$4,126,221	$456,972	$39,935,491	$44,518,684	$9,260,150	$1,328,814	$30,116,725	$40,705,689
Feb	$3,731,017	$200,456	$23,165,838	$27,097,312	$7,434,068	$839,679	$16,548,988	$24,822,735
Mar	$2,904,498	$249,900	$18,916,241	$22,070,639	$9,549,963	$108,664	$26,025,562	$35,684,189
Apr	$4,213,578	$209,366	$22,559,577	$26,982,522	$6,998,364	$19,929	$13,251,273	$20,269,566
May	$10,873,205	$202,397	$22,970,363	$34,045,964	$6,024,108	$5,543	$15,490,257	$21,519,908
Jun	$7,064,877	$575,927	$65,597,311	$73,238,115	$6,722,329	$0	$19,339,846	$26,062,175
Jul	$7,038,834	$874,234	$48,041,415	$55,954,483	$8,210,636	$38,643	$17,728,976	$25,978,255
Aug	$6,140,554	$143,857	$26,212,547	$32,496,959	$7,697,174	$1	$21,164,586	$28,861,761
Sep	$4,581,147	$405,308	$27,809,898	$32,796,353	$6,057,598	$13,611	$13,471,368	$19,542,577
Oct	$6,705,261	$794,271	$16,054,255	$23,553,788	$7,046,301	$0	$17,026,425	$24,072,727
Nov	$5,069,462	$635,697	$21,097,016	$26,802,175	$8,617,280	$22,639	$12,888,600	$21,528,519
Dec	$7,175,436	$996,292	$21,525,117	$29,696,846	$11,323,263	$117,573	$25,353,409	$36,794,245
Total	$69,624,091	$5,744,678	$353,885,070	$429,253,839	$94,941,235	$2,495,097	$228,406,015	$325,842,346
Share of Annual Charges	16.2%	1.3%	82.4%	100.0%	29.1%	0.8%	70.1%	100.0%

Table 3-55 shows the amount and percentages of regional balancing charge allocations across PJM for 2009. The largest share of charges was paid by RTO demand deviations and the second highest share of charges was paid by RTO supply deviations.

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Table 3-55 Regional balancing charges allocation: Calendar year 2009[88]

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$6,802,948 3.9%	$258,555 0.1%	$7,061,503 4.1%	$66,187,248 38.2%	$39,055,422 22.5%	$20,608,021 11.9%	$125,850,691 72.6%	$132,912,194 76.7%
East	$479,731 0.3%	$17,858 0.0%	$497,589 0.3%	$7,162,517 4.1%	$3,805,906 2.2%	$1,935,653 1.1%	$12,904,076 7.4%	$13,401,665 7.7%
West	$22,140,661 12.8%	$926,143 0.5%	$23,066,804 13.3%	$1,948,014 1.1%	$1,317,748 0.8%	$703,058 0.4%	$3,968,820 2.3%	$27,035,624 15.6%
Total	$29,423,340 17.0%	$1,202,556 0.7%	$30,625,896 17.7%	$75,297,778 43.4%	$44,179,076 25.5%	$23,246,732 13.4%	$142,723,586 82.3%	$173,349,483 100%

Deviations

Categories

Under the old rules, all operating reserve charges that resulted from paying balancing operating reserve credits were allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market. Table 3-54 shows monthly balancing operating reserve charges for calendar years 2008 and 2009. Under the new rules, only credits identified as related to deviations are allocated to deviations. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly net basis by zone, hub, or interface and summed by organization for the day. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES);[89] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[90] plus real-time exports scheduled through the EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

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

88 The total charges shown in Table 3-55 do not equal the total balancing charges shown in Table 3-54 because the totals in Table 3-54 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-55 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

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

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

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

- **Netting.** Demand and supply deviations are netted by zone, hub, or interface in which they occur but not across zones, hubs or interfaces. A negative deviation in a zone can be offset by a positive deviation that occurs in that zone. The sum of the net deviations by zone, hub, or interface is calculated for each region. An organization's total daily balancing operating reserve charges are equal to the sum of the three deviation categories, by region, for the day, multiplied by the regional daily balancing operating reserve rates.

Allocation

Under the old operating reserve construct, balancing operating reserve charges were assigned to total real-time deviations from day-ahead schedules. Under the new rules, only a subset of defined balancing reserve charges are assigned to deviations and deviations are separated into RTO and regional categories. Table 3-55 shows monthly real-time deviations for demand, supply and generator categories for 2008 and 2009. These deviations are the sum of all the regional deviations. Total deviations summed across the demand, supply, and generator categories were higher in 2009 than 2008 by 19,837,959 MWh, primarily as the result of a 31.3 percent increase in supply deviations, although demand deviations increased by 7.2 percent and generator deviations increased by 0.4 percent. From 2008 to 2009, the share of total deviations in the demand category decreased by 2.6 percentage points, the share of supply deviations increased by 4.5 percentage points, and the share of generator deviations decreased by 1.9 percentage points.

Effective December 1, 2008, new rules governing the calculation of generator deviations were implemented. Under the old rules, a generator was considered to deviate if the unit was operating at an actual output that was more than 10 percent from the PJM desired MW, or if they were operating at an output that was 5 percent, or 5 MW from their day-ahead schedule. Under the new rules, the ramp limited desired (RLD) MW is used instead to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate.[91] The goal of this rule change was to further incent generators to follow PJM dispatch instruction, and hence reduce generator deviations. While generator deviations actually increased by 0.4 percent overall for the year 2009 compared to 2008, this includes a spike in generator deviations in December 2009, when PJM experienced high volumes of congestion. Generator deviations for December were 30.0 percent higher than the annual monthly average. Comparing only the months of January through November 2009 to the same months in 2008 shows a 4.5 percent decrease in generator deviations for 2009.

91 See PJM Operating Reserve Revised Business Rules v6 "Ramp-limited RT Desired MW to determine deviations" for more details.

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Table 3-56 Monthly balancing operating reserve deviations (MWh): Calendar years 2008 and 2009

	2008 Deviations				2009 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	8,172,164	3,297,121	2,572,113	14,041,398	9,128,112	5,575,170	2,630,917	17,334,199
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,044,702	4,153,575	2,107,229	13,305,505
Mar	6,392,821	2,520,387	2,405,061	11,318,269	7,214,090	4,352,550	2,409,507	13,976,146
Apr	5,951,654	3,127,726	2,224,157	11,303,537	6,873,427	3,836,896	2,275,153	12,985,477
May	6,624,696	3,787,650	2,699,616	13,111,962	6,958,699	5,184,983	2,382,351	14,526,033
Jun	8,117,669	3,179,999	2,644,016	13,941,684	8,569,879	4,603,052	2,635,991	15,808,922
Jul	9,237,956	3,914,230	2,213,828	15,366,014	9,233,511	5,129,409	2,243,337	16,606,257
Aug	8,296,485	4,000,974	2,275,294	14,572,753	9,961,944	5,425,344	2,427,539	17,814,827
Sep	7,360,536	3,691,646	2,577,095	13,629,277	7,972,378	4,171,876	2,109,506	14,253,759
Oct	6,792,603	3,538,950	2,404,069	12,735,621	7,028,775	4,543,635	2,203,723	13,776,133
Nov	6,561,634	3,586,432	2,267,083	12,415,148	6,742,675	4,248,221	2,193,013	13,183,910
Dec	8,399,099	4,898,506	1,775,964	15,073,569	8,301,680	4,682,157	3,113,047	16,096,884
Total	88,635,377	42,589,911	28,604,806	159,830,094	95,029,874	55,906,867	28,731,313	179,668,054
Share of Annual Deviations	55.5%	26.6%	17.9%	100.0%	52.9%	31.1%	16.0%	100.0%

A breakdown of real-time load, real-time exports, and deviations in each region is shown in Table 3-57. RTO deviations are classified as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions. Real time load was 365,845,671 MWh in the Eastern Region for 2009, and 300,223,483 in the Western Region. Eastern demand deviations were the highest of all deviation categories (excluding RTO) with 58,407,190 MWh. Total deviations in the Eastern Region were 40.1 percent higher than deviations in the western region in 2009.

Table 3-57 Regional charges determinants (MWh): Calendar year 2009

	Reliability Charge Determinants			Deviation Charge Determinants				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	666,069,154	26,013,760	692,082,914	95,029,874	55,906,867	28,731,313	179,668,054	871,750,967
East	365,845,671	13,803,483	379,649,154	58,407,190	30,639,519	15,609,547	104,656,256	484,305,410
West	300,223,483	12,210,277	312,433,760	36,377,638	25,195,498	13,121,766	74,694,902	387,128,661

Balancing Operating Reserve Charge Rate

Under the new balancing operating reserve cost allocation construct, PJM calculates six separate balancing rates, a reliability rate for each region, and a deviation rate for each region. The reliability rates are equal to the total reliability credits divided by real-time load plus exports. The deviation rates are calculated as the total deviation credits divided by the sum of the demand, supply, and generation deviations. RTO rates are based on RTO credits, while the regional rates are based on regional credits. See Table 3-52 for how these credits are allocated.

Figure 3-14 shows the daily RTO reliability and deviation rates for 2009. The average daily RTO deviation rate for 2009 was $0.6723 per MWh, while the average daily RTO reliability rate was $0.0092 per MWh. The largest daily rate occurred on March 3, 2009, when the RTO deviation rate was $5.3569 per MWh.[92]

Figure 3-14 Daily RTO reliability and deviation rates ($/MWh): Calendar year 2009

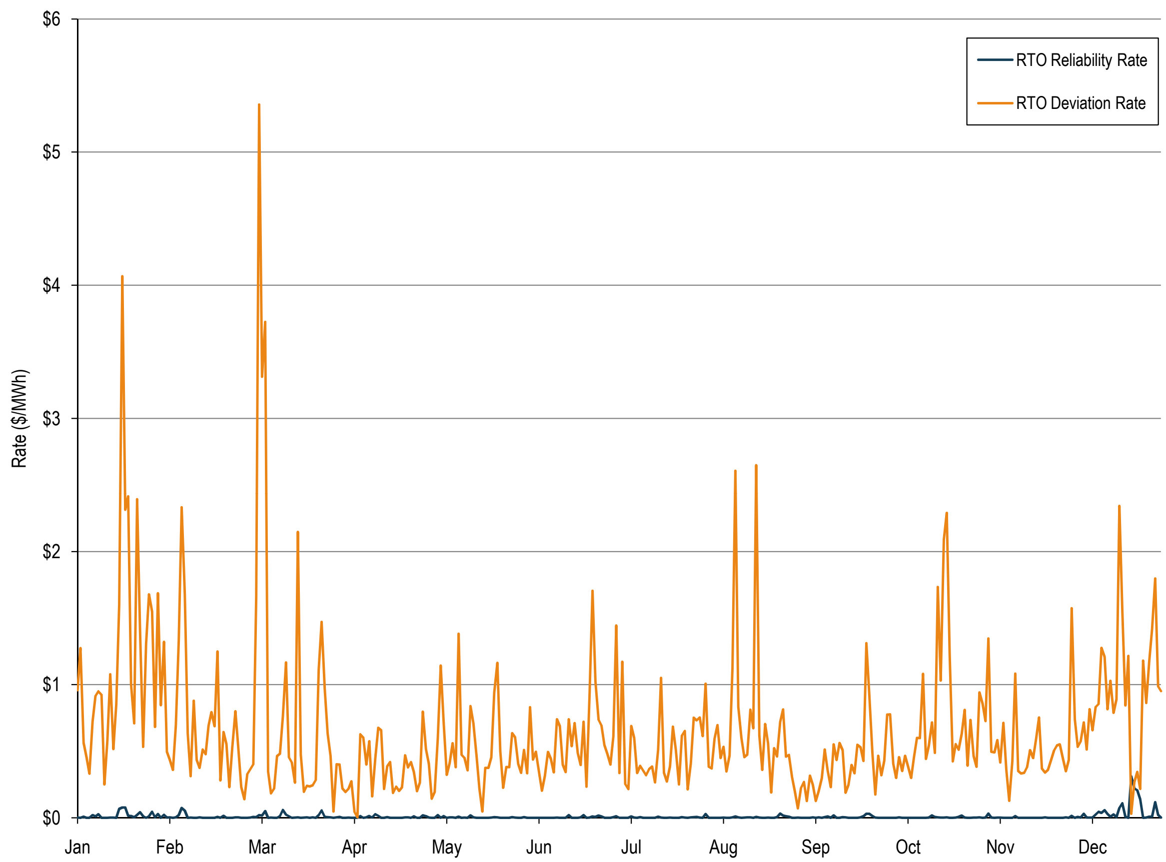

Figure 3-15 shows the daily regional reliability and deviation rates for 2009.

92 For further analysis of March 3, 2009, see *2009 Quarterly State of the Market Report for PJM: January through June*, Section 3, "Energy Market, Part 2".

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Figure 3-15 Daily regional reliability and deviation rates ($/MWh): Calendar year 2009

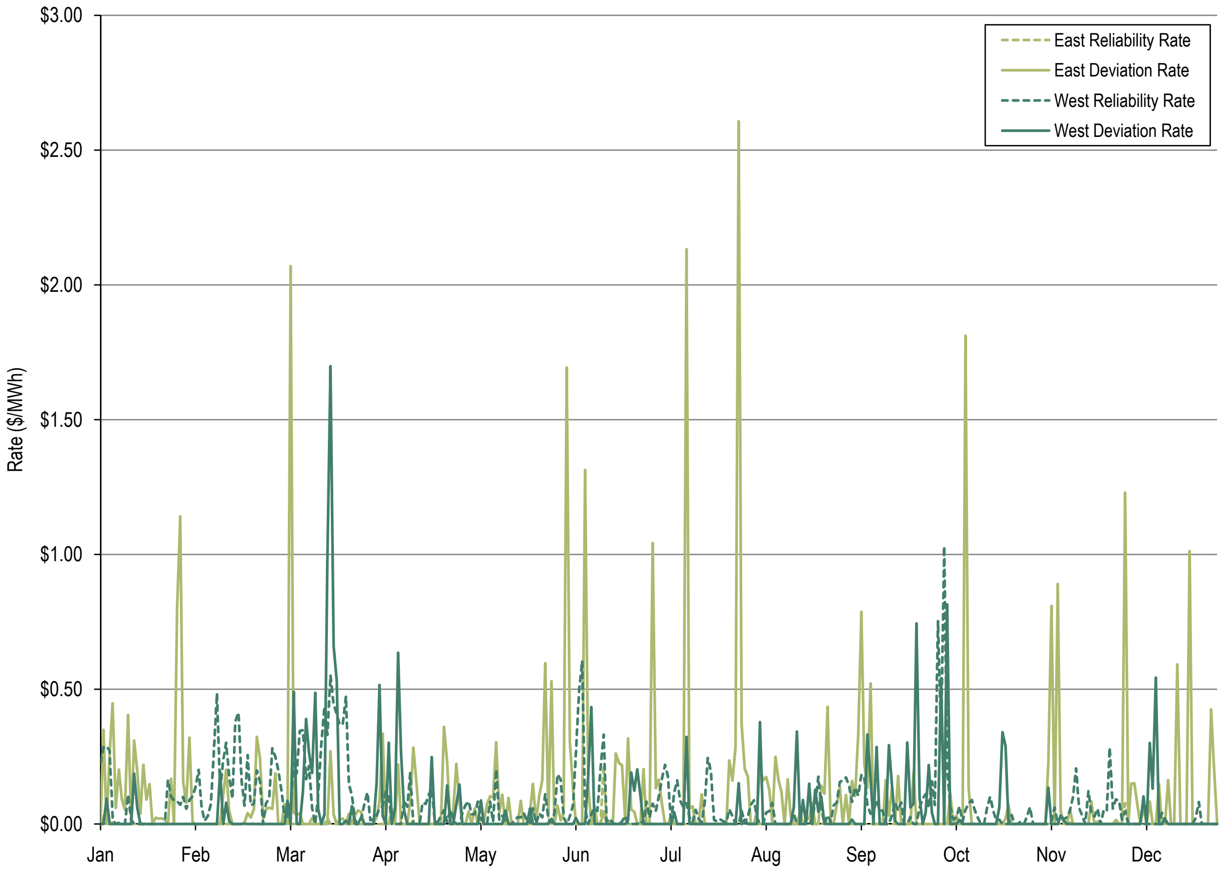

Table 3-58 shows the rates for each region in each category. Regional reliability rates are substantially higher than the RTO reliability rate. The RTO deviation rate is substantially higher than the regional deviation rates.

Table 3-58 Regional balancing operating reserve rates ($/MWh): Calendar year 2009

	Reliability	Deviations
RTO	0.0092	0.6723
East	0.0013	0.1149
West	0.0785	0.0516

Operating Reserve Credits by Category

Figure 3-16 shows that the largest share of total operating reserve credits, 59.6 percent, was paid to resources in the balancing energy market during 2009 and 69.3 percent of total operating reserve credits were in the balancing category, which includes the balancing energy market, real-time transactions, and lost opportunity costs. Figure 3-16 also shows that 29.9 percent of total operating reserve credits were paid to resources in the day-ahead category, which includes the Day-Ahead Energy Market and day-ahead transactions. The remaining 0.8 percent of total credits was paid to resources in the synchronous condensing category. The balancing category share of total operating reserve credits in 2009 is 13.1 percentage points lower in 2009 than the share of 82.5 percent in 2008.

Figure 3-16 Operating reserve credits: Calendar year 2009

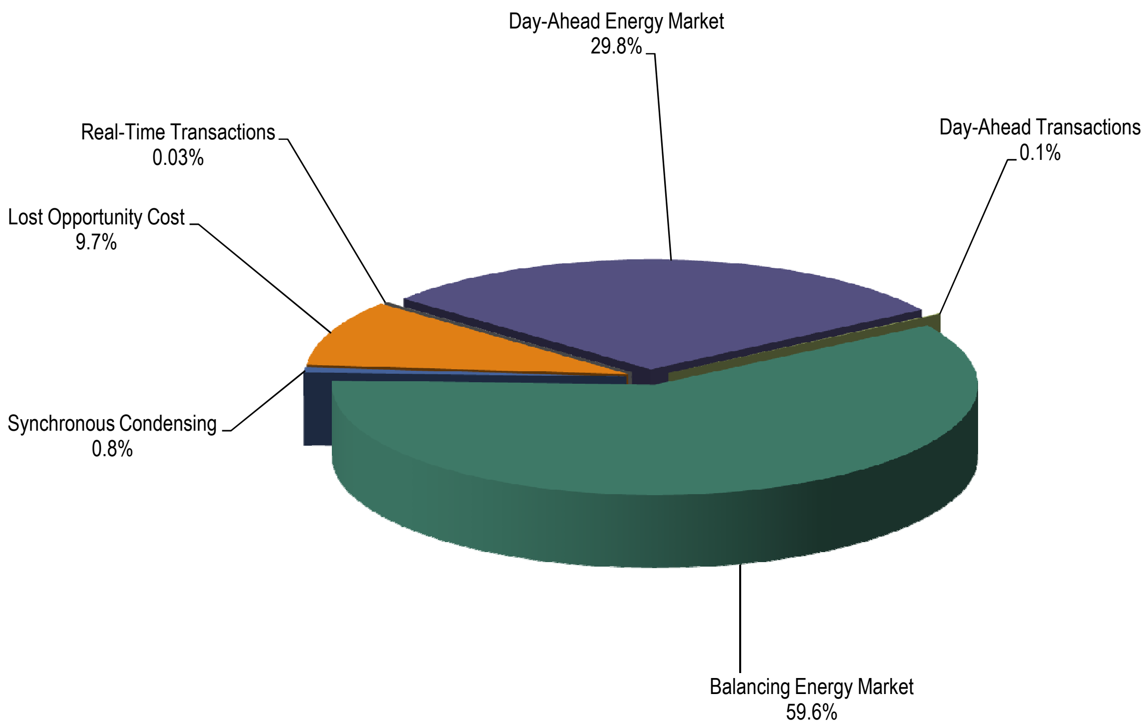

Table 3-59 shows the monthly totals for each type of credit for 2009. The winter months of 2009, which include January, February, November, and December, accounted for 37.3 percent of operating reserve credits, while the summer months, which include May, June, July and August, accounted for 32.0 percent and the shoulder months 30.8 percent. These credits do not equal the total amount of charges paid of $325,842,346. The difference of $7,715,284 was operating reserve billing adjustments made by PJM directly to customers' bills.

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Table 3-59 Credits by month (By operating reserve market): Calendar year 2009

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$9,260,150	$0	$1,328,814	$26,534,188	$0	$3,582,536	$40,705,688
Feb	$7,434,068	$0	$839,679	$14,413,879	$31,258	$2,103,852	$24,822,736
Mar	$9,542,383	$7,580	$108,664	$22,307,277	$13,249	$3,557,415	$35,536,568
Apr	$6,998,364	$0	$19,929	$10,751,270	$6,942	$1,833,546	$19,610,052
May	$6,024,108	$0	$5,543	$13,977,804	$0	$1,512,453	$21,519,908
Jun	$6,711,471	$10,858	$0	$16,160,774	$0	$2,540,536	$25,423,640
Jul	$8,183,242	$27,394	$38,643	$15,628,869	$0	$2,100,106	$25,978,255
Aug	$7,636,586	$60,588	$1	$15,630,231	$0	$5,402,076	$28,729,482
Sep	$6,057,599	$0	$13,611	$10,580,172	$0	$2,803,567	$19,454,949
Oct	$6,949,167	$97,135	$0	$14,624,824	$39,844	$1,618,538	$23,329,507
Nov	$8,587,424	$29,855	$22,640	$9,126,338	$0	$1,627,014	$19,393,272
Dec	$11,323,161	$102	$117,573	$20,001,841	$0	$2,180,329	$33,623,006
Total	$94,707,723	$233,512	$2,495,097	$189,737,468	$91,293	$30,861,969	$318,127,062
Share of Credits	29.8%	0.1%	0.8%	59.6%	0.0%	9.7%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-60 shows the distribution of credits by unit type and type of operating reserve. (Each row sums to 100 percent.) Steam units received the most operating reserve credits, of which 42.6 percent were received in the Day-Ahead Energy Market and 57.4 percent in the balancing energy market. For combustion turbine units, 95.5 percent of credits were received in the balancing market.

Table 3-60 Credits by unit types (By operating reserve market): Calendar year 2009

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	41.0%	0.0%	58.1%	0.9%	$103,035,927
Combustion Turbine	1.4%	3.1%	81.8%	13.7%	$80,115,798
Diesel	2.0%	0.0%	82.7%	15.3%	$251,962
Hydro	0.0%	0.4%	99.6%	0.0%	$280,485
Landfill	0.0%	0.0%	0.0%	100.0%	$13,297,176
Nuclear	0.0%	0.0%	0.0%	100.0%	$150,645
Steam	42.6%	0.0%	53.1%	4.3%	$120,319,669
Wind Farm	0.0%	0.0%	1.6%	98.4%	$374,680

Table 3-61 shows the distribution of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and conventional steam units received 98.7 percent of the day-ahead generator credits. Combustion turbines received 100 percent of the synchronous condensing credits.

Table 3-61 Credits by operating reserve market (By unit type): Calendar year 2009

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	44.6%	0.0%	31.5%	2.9%
Combustion Turbine	1.2%	100.0%	34.5%	35.6%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.1%	1.2%
Landfill	0.0%	0.0%	0.0%	43.1%
Nuclear	0.0%	0.0%	0.0%	0.5%
Steam	54.1%	0.0%	33.7%	16.6%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$94,707,723	$2,495,097	$189,739,803	$30,883,718

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to LMP. Noneconomic generation includes units that are producing energy but at a higher offer price than the LMP. Noneconomic generation includes units assigned by PJM to run and units not assigned by PJM to run or to provide regulation. Regulation generation includes units assigned by PJM to provide regulation. The level of noneconomic generation is an indicator of the level of generation that may require operating reserve credits. However, the data are hourly and some generation that is noneconomic for an hour may receive adequate market revenues during other hours to offset any shortfall.[93]

Table 3-62 shows the percentage of total PJM self-scheduled generation, economic generation, noneconomic generation and regulation generation for 2009.

Table 3-62 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2009

	All Hours	On Peak	Off Peak
Self-scheduled generation	25.5%	24.0%	29.0%
Economic generation	63.3%	68.7%	50.3%
Noneconomic generation	9.7%	6.5%	17.4%
Regulation generation	1.5%	0.8%	3.3%
Total	100%	100%	100%

Table 3-63 presents the share of self-scheduled, economic, noneconomic and regulation generation by unit type. (Each column adds to 100 percent.) In 2009, steam units represented 92.5 percent of all self-scheduled generation, 89.9 percent of all economic generation and 73.7 percent of noneconomic generation.

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

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Table 3-63 PJM generation by unit type receiving operating reserve payments: Calendar year 2009

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.1%	9.3%	24.3%	31.0%
Combustion turbine	0.2%	0.3%	2.0%	0.0%
Diesel	0.2%	0.0%	0.0%	0.0%
Hydroelectric	3.0%	0.5%	0.0%	0.0%
Steam	92.5%	89.9%	73.7%	69.0%
Wind	1.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

Table 3-64 presents the share of each unit type by self-scheduled, economic, noneconomic and regulation generation. (Each row adds to 100 percent.) For example, in 2009, 26.5 percent of steam unit generation was self-scheduled, 64.3 percent was economic, 8.1 percent was noneconomic and the remaining 1.2 percent was regulation generation. In 2009, 98.7 percent of wind generation and 71.1 percent of hydroelectric generation was self-scheduled. In 2009, 45.2 percent of combustion turbine generation was noneconomic, which is consistent with Table 3-61 which shows that a large percentage of balancing generator credits was paid to CTs.

Table 3-64 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2009

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	8.4%	62.0%	24.7%	5.0%	100%
Combustion turbine	12.8%	41.8%	45.2%	0.1%	100%
Diesel	80.3%	13.9%	5.8%	0.0%	100%
Hydroelectric	71.1%	28.9%	0.0%	0.0%	100%
Steam	26.5%	64.3%	8.1%	1.2%	100%
Wind	98.7%	1.3%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-65 compares the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generation charges are defined in this table as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.[94] On average, 53.1 percent of balancing generator charges and 51.4 percent of lost opportunity cost charges were paid by generators deviating in the Eastern Region while these generators received 60.6 percent of balancing generator credits and 79.9 percent of lost opportunity cost credits. Table 3-65 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 8.4 percent of all operating reserve charges and generator credits were 68.7 percent of all operating reserve credits.

94 The Eastern Region contains the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, RECO, and AECO Control Zones. The Western Region includes the AEP, AP, ComEd, DLCO, and DAY Control Zones.

Table 3-65 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2009

Eastern Region						
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit
Jan	$2,003,885	$299,205	$2,303,090	$21,129,695	$2,617,930	$23,747,625
Feb	$790,550	$164,106	$954,656	$7,821,619	$1,685,163	$9,506,782
Mar	$1,469,084	$340,198	$1,809,282	$13,211,647	$2,283,617	$15,495,264
Apr	$498,591	$157,780	$656,371	$3,992,645	$1,098,113	$5,090,758
May	$693,618	$113,976	$807,594	$6,823,179	$1,312,397	$8,135,576
Jun	$1,003,287	$199,563	$1,202,850	$8,774,095	$2,017,742	$10,791,837
Jul	$901,022	$153,109	$1,054,130	$10,024,256	$1,855,776	$11,880,032
Aug	$1,079,421	$409,943	$1,489,364	$11,091,698	$4,841,026	$15,932,725
Sep	$572,257	$207,710	$779,966	$5,571,005	$2,602,756	$8,173,762
Oct	$953,675	$132,000	$1,085,676	$9,951,855	$1,333,063	$11,284,918
Nov	$677,193	$141,054	$818,246	$5,956,365	$1,139,586	$7,095,951
Dec	$1,661,238	$211,376	$1,872,614	$16,984,127	$1,625,960	$18,610,087
Average	53.1%	51.4%	52.8%	60.6%	79.9%	63.4%

Western Region								
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	$1,670,026	$279,307	$1,949,334	$5,404,493	$964,606	$6,369,099	10.4%	74.0%
Feb	$726,523	$172,132	$898,655	$6,592,259	$418,689	$7,010,948	7.5%	66.5%
Mar	$1,359,557	$286,649	$1,646,206	$9,095,630	$1,273,798	$10,369,428	9.7%	72.8%
Apr	$530,487	$161,839	$692,326	$6,758,625	$735,433	$7,494,058	6.7%	64.2%
May	$700,650	$132,040	$832,690	$7,154,625	$200,056	$7,354,681	7.6%	72.0%
Jun	$920,146	$224,107	$1,144,253	$7,386,679	$522,794	$7,909,474	9.0%	73.6%
Jul	$635,412	$131,550	$766,962	$5,604,614	$244,330	$5,848,944	7.0%	68.2%
Aug	$866,957	$356,962	$1,223,919	$4,538,533	$561,050	$5,099,583	9.4%	73.2%
Sep	$548,659	$186,125	$734,784	$5,009,167	$200,811	$5,209,978	7.8%	68.8%
Oct	$873,630	$129,657	$1,003,287	$4,672,969	$285,475	$4,958,444	8.6%	69.6%
Nov	$590,510	$129,344	$719,853	$3,169,974	$487,428	$3,657,402	7.1%	55.4%
Dec	$1,516,925	$213,325	$1,730,251	$3,017,714	$554,369	$3,572,083	9.8%	66.0%
Average	46.9%	48.6%	47.2%	39.4%	20.1%	36.6%	8.4%	68.7%

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Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

The MMU has reviewed and analyzed the net impact of allocating a proportion of balancing operating reserve credits to real-time load and exports. Credits that are received by generators that operate for reliability purposes are now paid as charges by organizations with real-time load and exports. Credits that are received by generators that are operating for deviation purposes are still paid as charges by organizations that have supply, withdrawal, and/or generator deviations. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, determined to be real-time load and exports. In order to determine the impact of this rule change, the MMU calculated what balancing operating reserve charges would have been under the old rules and compared it to what actually happened in 2009.

Total reliability and deviation balancing operating reserve credits were $173,349,483 in 2009.[95] Table 3-66 shows each category of credits by region.

Table 3-66 Regional balancing operating reserve credits: Calendar year 2009

	Reliability Credits	Deviation Credits	Total Credits
RTO	$7,061,503	$125,850,691	$132,912,194
East	$497,589	$12,904,076	$13,401,665
West	$23,066,804	$3,968,820	$27,035,624
Total	$30,625,896	$142,723,586	$173,349,483

Table 3-67 shows the total amount of deviations in the demand, supply, and generator categories for 2009.

Table 3-67 Total deviations: Calendar year 2009

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	95,029,874	55,906,867	28,731,313	179,668,054

Under the old operating reserve construct, total credits for a day would have been calculated using demand, supply, and generator deviations and the resultant balancing rate would have been applied to each organization's demand, supply, and generator deviations to calculate total charges.

For illustrative purposes only, the balancing rate shown in Table 3-68 was calculated as the total credits in Table 3-66 divided by total deviations in Table 3-67, or $173,349,483/179,668,054, for a rate of $0.9648 per MWh. The MMU derived the rates on a daily basis and re-calculated organizational charges.

Table 3-68 Charge allocation under old operating reserve construct: Calendar year 2009

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	95,029,874	55,906,867	28,731,313	179,668,054
Balancing Rate ($/MWh)	0.9648	0.9648	0.9648	0.9648
Charges ($)	$91,687,861	$53,940,732	$27,720,889	$173,349,483

95 Only balancing generator charges were in this analysis. The charges shown in this section do not include lost opportunity cost, cancellation, or local charges.

Under the new operating reserve construct, rates are calculated separately for reliability and deviation categories in the Eastern, Western, and RTO Regions, resulting in six balancing rates. The Eastern and Western reliability rates are calculated by taking each region's daily reliability credits and dividing by each region's real-time load and exports. These regional rates are then charged to each organization's regional real-time load and exports. The RTO reliability rate is calculated by taking the total RTO reliability rates for the day and dividing it by the sum of eastern and western real-time load and exports. This rate is then charged to the sum of an organization's eastern and western real-time load and exports. Regional deviation credits are charged to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at hubs that span both regions apply to RTO deviations).[96] Total RTO deviations are the sum of the eastern deviations, western deviations, and the deviations at hubs that span both regions.

For 2009, charges were actually allocated as shown in Table 3-69. For illustrative purposes only, the reliability and deviation rates in the table are the annual credits divided by either real-time load and exports or total deviations ($7,061,503 / 692,082,914 = .0102). The charges are calculated based on the actual daily rates.

Table 3-69 Actual regional credits, charges, rates and charge allocation (MWh): Calendar 2009

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$7,061,503	692,082,914	0.0102	$7,061,503	$125,850,691	179,668,054	0.7005	$125,850,691	$132,912,194
East	$497,589	379,649,154	0.0013	$497,589	$12,904,076	104,656,256	0.1233	$12,904,076	$13,401,665
West	$23,066,804	312,433,760	0.0738	$23,066,804	$3,968,820	74,694,902	0.0531	$3,968,820	$27,035,624
Total	$30,625,896	692,082,914	NA	$30,625,896	$142,723,586	179,668,054	NA	$142,723,586	$173,349,483

The difference between the charges based on the old operating reserve construct (Table 3-68) and the actual charges allocated under the current rules is shown in Table 3-70, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

Table 3-70 Difference in total charges between old rules and new rules: Calendar year 2009

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$91,687,861	$53,940,732	$27,720,889	$173,349,483
Charges (Current)	$29,423,340	$1,202,556	$30,625,896	$75,297,778	$44,179,076	$23,246,732	$142,723,586
Difference	$29,423,340	$1,202,556	$30,625,896	($16,390,083)	($9,761,656)	($4,474,157)	($30,625,896)

An increase of $30,625,896 of charges was assigned to real-time load and exports for 2009. Real-time load paid an additional $29,423,340, while real-time exports paid an additional $1,202,556. These increases were matched by a decrease of $16,390,083 in charges to demand deviations, a decrease of $9,761,656 in charges to supply deviations, and a decrease of $4,474,157 in charges to generator deviations. Reliability charges accounted for 17.7 percent of total balancing operating reserve charges.

96 Only two hubs span across both the eastern and western regions: the Dominion Hub and the Western Int. Hub.

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Impact on decrement bids and incremental offers

The MMU has estimated the impact of the new balancing operating reserve cost allocation construct on virtual activity. The level of virtual activity that was not otherwise netted out was calculated by organization for increment offers and decrement bids. All organizational deviations were grouped into regions. "Total Increment Offers" and "Total Decrement Bids", shown in Table 3-71, is the sum of cleared virtual activity for 2009. "Adjusted Increment Offer Deviations" and "Adjusted Decrement Bid Deviations" are the net deviations for each type of virtual trade that were not offset. For example, in January 2009, of the 10,407,394 MWh of cleared increment offers, 7,841,756 MWh were netted by other deviations, resulting in 2,565,639 MWh of increment offers being charged balancing operating reserve deviation charges.

Table 3-71 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): Calendar year 2009

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	10,407,394	12,554,252	2,565,639	3,639,601
Feb	9,063,314	10,452,872	2,020,685	2,506,114
Mar	9,929,332	11,282,869	2,114,827	2,444,352
Apr	8,181,571	10,008,029	1,807,709	2,209,075
May	9,562,558	10,395,649	2,753,133	2,358,022
Jun	8,910,238	10,639,623	2,636,356	2,637,496
Jul	9,066,758	10,828,533	2,710,078	3,014,685
Aug	9,186,533	12,370,077	3,006,961	3,913,433
Sep	8,787,276	10,415,029	2,545,261	2,972,666
Oct	9,804,389	11,684,851	2,344,278	2,586,091
Nov	9,311,052	10,797,920	2,286,985	2,498,129
Dec	8,689,316	11,158,575	2,142,485	2,694,103
Total	110,899,732	132,588,277	28,934,395	33,473,766

When multiplied by the regional deviation rates, the total amount of charges paid by these deviations in 2009 was $60,795,622. Total deviation charges using the actual method of including decrement bids in the deviation calculation were $75,297,778, as shown in Table 3-70.

In order to determine what these deviation charges would have been under the old method, balancing operating reserve rates were determined for each day. The rates were calculated using the sum of reliability credits for the RTO, eastern region, western region, and deviation credits for the RTO, eastern region, and western region, and dividing by the total amount of deviations across all regions. Total charges were calculated for each company using this balancing rate and the sum of their adjusted increment offer and decrement bids. The resulting total amount of charges that would have been paid in 2009 was $71,237,186. The monthly differences can be seen in Table 3-72.

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Table 3-72 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2009

Month	Charges Under Current Rules	Charges Under Old Rules	Difference
Jan	$9,672,322	$10,738,258	($1,065,936)
Feb	$4,034,001	$5,681,839	($1,647,837)
Mar	$6,745,711	$8,589,442	($1,843,731)
Apr	$2,331,339	$2,736,472	($405,133)
May	$3,602,363	$4,020,105	($417,741)
Jun	$4,827,989	$5,606,584	($778,595)
Jul	$4,792,394	$5,383,784	($591,390)
Aug	$7,234,696	$7,720,394	($485,698)
Sep	$3,973,924	$4,772,689	($798,765)
Oct	$4,664,169	$5,536,136	($871,967)
Nov	$3,380,119	$3,836,906	($456,787)
Dec	$5,536,595	$6,614,578	($1,077,983)
Total	$60,795,622	$71,237,186	($10,441,564)

The net result is that virtual offers and bids paid $10,441,564 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports. A summary showing this breakdown for each region is shown in Table 3-73.

Table 3-73 Summary of impact on virtual bids under balancing operating reserve allocation: Calendar year 2009

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Current Rules	Balancing Rate Under Old Rules	Charges Under Current Rules	Charges Under Old Rules	Differerence
RTO	28,934,395.37	33,473,765.63	62,408,161.00	0.8629	1.1300	54,696,020.66	71,237,185.54	(16,541,164.88)
East	16,265,449.13	20,838,704.18	37,104,153.30	0.1204	0.0000	4,776,624.74	0.00	4,776,624.74
West	12,597,096.94	12,390,014.85	24,987,111.79	0.0544	0.0000	1,322,976.53	0.00	1,322,976.53

Segmented Make Whole Payments

Under the old operating reserve construct, balancing operating reserves for units were evaluated over the entire 24-hour period of the day. Under the new construct,

> "Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources) and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources). Startup costs (shut down costs for demand resources), as applicable,

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will be included in the segment represented by the longer of the day-ahead schedule or minimum run time (minimum down time for demand resources)."[97]

The primary intent of this rule was to provide incentives for generating units to follow PJM dispatch past their day-ahead schedule or minimum run time. Splitting these credits into two segments was to create compensation which would reimburse resources when it was not economical for them to run, but when they were still needed by PJM. It was also to allow resources to keep their revenues from economical hours, thereby providing incentives to offer flexible schedules and to follow dispatch.

The MMU analyzed the impact of segmented make whole payments on balancing operating reserves since the establishment of the rule. The MMU compared what balancing credits would have been for each unit for each day under the old rules to what the credits were under the new rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $8,174,406 higher, or 4.10 percent, from December 1, 2008 through December 31, 2009. The total increase for the calendar year 2009 was $7,489,486, or 4.13 percent. Table 3-74 provides a breakdown of monthly differences between the two methods of calculation since December 2008.

Table 3-74 Impact of segmented make whole payments: December 2008 through December 2009

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
Total		$199,302,047	$207,476,453	$8,174,406

Table 3-75 shows the effect of segmented make whole payments on each type of unit that received balancing operating reserve credits for the period from December 1, 2008 through December 31, 2009. "Number of Unit-Days" in the table is the count of units that received balancing credits each day, summed across the entire year. For example, it can be said that an average of 4.6 combined-cycle units received credits for each day of the year (1,667 / 365 = 4.6). The average daily amount received in credits for a unit in each method of calculation was analyzed to show the impact of an average day for each type of unit. The last three columns in the table show the total difference in credits for the time period across each unit type.

97 PJM. "Manual 18: Operating Agreement Accounting" Revision 43 (January 20, 2010), Section 5.3.1.

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Table 3-75 Impact of segmented make whole payments (By unit type): December 2008 through December 2009

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	1,657	$1,865	$4,319	$2,454	$3,090,233	$7,157,021	$4,066,788
Large Frame Combustion Turbine (135 - 180 MW)	386	$5,988	$10,221	$4,233	$2,311,413	$3,945,418	$1,634,005
Medium Frame Combustion Turbine (30 - 65 MW)	2,924	$1,774	$2,063	$289	$5,186,443	$6,032,231	$845,788
Medium-Large Frame Combustion Turbine (65 - 125 MW)	434	$2,959	$4,296	$1,337	$1,284,040	$1,864,256	$580,216
Sub-Critical Coal	570	$299	$998	$699	$170,667	$568,868	$398,201
Petroleum/Gas Steam (Pre-1985)	79	$875	$5,579	$4,704	$69,107	$440,750	$371,643
Petroleum/Gas Steam (Post-1985)	222	$659	$1,600	$941	$146,272	$355,217	$208,945
Small Frame Combustion Turbine (0 - 29 MW)	119	$3,200	$3,538	$338	$380,847	$421,010	$40,164
Hydro	26	$112	$904	$793	$2,900	$23,505	$20,605
Super-Critical Coal	5	$30	$946	$916	$149	$4,729	$4,580
Diesel	26	$610	$743	$133	$15,850	$19,320	$3,470

Combined-cycle units were most affected by the rule change. Under the old rules, these units would have been paid $3,090,233, and with segmented make whole payments, the units received $7,157,021, for a total difference of $4,066,788, or a 131.6 percent increase. This represents 49.8 percent of the total increase of credits. The four types of combustion turbines received a 37.9 percent of the increase, and steam units, which include sub and super-critical coal units, and petroleum and natural gas steam units, received 12.0 percent of the increase. Table 3-76 shows this breakdown.

Table 3-76 Share of balancing operating reserve increases for segmented make whole payments (By unit type): December 2008 through December 2009

Unit Type	Share of Increase
Combined-Cycle	49.8%
Steam	12.0%
Combustion Turbines	37.9%
Diesel	0.0%
Hydro	0.3%

Unit Operating Parameters

The use of restrictive operating parameters to exercise market power and inflate operating reserve credits was addressed, based on the MMU's analysis and positions, in the revised operating reserve rules. The MMU's prior analyses indicated that operating reserve credits may result from the submission of artificially restrictive, unit-specific operating parameters.[98] The MMU also pointed out that restrictive operating parameters can interact with unit-specific markups to increase operating reserve payments to units.

98 See *2008 State of the Market Report for PJM*, Section 3, "Energy Market, Part 2", at "Operating Reserve".

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The new operating reserves rules address the parameter issue by establishing a parameter limited schedule (PLS) that helps prevent the use of restrictive operating parameters when units have local market power. Table 3-77 shows the parameter limited matrix for periods that are currently effective.[99]

Table 3-77 Table 37 Unit Parameter Limited Schedule Matrix

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 125 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Units may request exceptions to the values in the matrix. The MMU analyzed the impact of these exceptions. The only units included in the analysis were units put on their cost schedule after failing the TPS test.

There were only 216 events, including 44 units, when a unit with a PLS exception was capped and received balancing operating reserve credits. Table 3-78 shows the number of unique units and the number of events that occurred.

Table 3-78 Units receiving credits from a parameter limited schedule: December 2008 through December 2009

Unit Type	Number of Units	Observations
Sub-Critical Coal	23	87
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	79
Combined-Cycle	4	7
Super-Critical Coal	3	3
Large Frame Combustion Turbine (135 - 180 MW)	2	38
Petroleum/Gas Steam (Post-1985)	1	1
Petroleum/Gas Steam (Pre-1985)	1	1

99 See PJM “Parameter Limited Schedule Matrix,” for parameter levels at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/20080916-parameter-limited-schedule-matrix.ashx> (104 KB).

Concentration of Unit Ownership for Operating Reserve Credits

Market Power Issues

The MMU has pointed out that the exercise of market power by units that are paid operating reserve credits has contributed to the level of operating reserve charges paid by PJM members. Such market power was exercised through the use of mark ups by units that were exempt from local market power rules and through the submission of inflexible operating parameters. The mark up issue was resolved by FERC's acting on May 16, 2008, to end the prior exemptions from offer capping.[100] Units that were exempt had, prior to that time, exercised market power by charging substantial mark ups over cost when they had local market power due to PJM's need for the units to supply local operating reserves. As a result, 2009 was the first full year in which there were no exemptions from offer capping. The inflexible operating parameter issue was largely resolved by the introduction of new PJM rules governing parameter limited schedules.

Markup

The MMU analyzed the top 10 units receiving operating reserve credits to determine the contribution that markup makes to operating reserve payments.[101] The markup for the top 10 units averaged -0.7 percent in 2009, the only time it has been negative since 2001. The markup for the top 10 units is a weighted average, weighted by generator output when operating reserve credits are paid.

The generation owner with the largest share of the top 10 units that received operating reserve credits was 67.9 percent, and had a weighted average markup of 0.0 percent in 2009. This generation mix included two combined-cycle units, and a coal-fired steam unit. The second generation owner received 22.5 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of -11.8 percent. This includes four coal-fired steam plants. The third generation owner received 3.6 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of -22.9 percent in 2009. This was a combined-cycle unit.

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

100 123 FERC ¶ 61,169 (May 16, 2008).

101 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 11 (December 2, 2009). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

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Top 10 Units

Despite the fact that the market power issues have been addressed, the concentration of operating reserve credits increased in 2009. As Table 3-79 shows, the top 10 units receiving total operating reserve credits, which makes up less than 1 percent of all units in PJM's footprint, received 37.1 percent of total operating reserve credits in 2009, almost twice as much as 2008. The top 20 units received 46.0 percent of total operating reserve credits in 2009 and 25.8 percent in 2008. In 2009, the top generation owner received 32.8 percent of the total operating reserve credits paid, an increase over 2008, when the top generation owner received 24.9 percent of the total operating reserve credits.

Table 3-79 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2009

	Top 10 Units Credit Share	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%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%

Table 3-80 shows the distribution of operating reserve credits to units by zone. The top three zones accounted for 64.2 percent of the total. The PSEG Control Zone had the largest share of credits with 33.1 percent, the AEP Control Zone was the second highest with 18.7 percent, and the Dominion Control Zone was third with a 12.4 percent share.

Table 3-80 Unit operating reserve credits for units (By zone): Calendar year 2009

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$513,710	$944	$791,938	$117,509	$1,424,100	0.4%
AEP	$8,723,238	$5,133	$48,980,822	$1,674,940	$59,384,133	18.7%
AP	$3,747,192	$1,101	$6,805,759	$2,422,733	$12,976,784	4.1%
BGE	$7,007,778	$0	$4,356,403	$42,099	$11,406,280	3.6%
ComEd	$2,435,143	$0	$9,019,152	$2,150,192	$13,604,487	4.3%
DAY	$1,300,875	$4,430	$2,120,856	$31,311	$3,457,472	1.1%
Dominion	$3,291,700	$0	$18,349,168	$17,613,332	$39,254,200	12.4%
DPL	$5,684,241	$173,552	$9,064,286	$609,202	$15,531,281	4.9%
DLCO	$995,576	$0	$1,582,810	$179,765	$2,758,151	0.9%
JCPL	$1,354,488	$0	$3,669,397	$55,396	$5,079,281	1.6%
Met-Ed	$725,864	$0	$2,202,305	$14,948	$2,943,117	0.9%
PECO	$3,212,154	$0	$2,711,564	$501,750	$6,425,468	2.0%
PENELEC	$1,189,888	$79,317	$2,048,576	$1,129,565	$4,447,346	1.4%
Pepco	$7,464,662	$0	$16,003,899	$3,287,739	$26,756,300	8.4%
PPL	$566,776	$0	$5,885,515	$846,691	$7,298,983	2.3%
PSEG	$46,494,438	$2,230,621	$56,147,353	$206,545	$105,078,957	33.1%
Total	$94,707,723	$2,495,097	$189,739,803	$30,883,718	$317,826,341	100.0%

Table 3-81 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $40,271,049 for 2009, or 12.7 percent of the total operating reserve credits paid to all units. The cumulative distribution column shows that the top 10 units had a 37.1 percent share of the total operating reserve credits in 2009. The top organization had a 32.8 percent share of the total credits, or $104,362,793. The top 10 organizations receiving credits had a cumulative share of 85.4 percent.

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Table 3-81 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2009

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$40,271,049	12.7%	12.7%	$104,362,793	32.8%	32.8%
2	$26,582,418	8.4%	21.0%	$53,684,600	16.9%	49.7%
3	$13,129,115	4.1%	25.2%	$30,268,335	9.5%	59.3%
4	$8,972,470	2.8%	28.0%	$18,858,384	5.9%	65.2%
5	$7,153,457	2.3%	30.2%	$15,000,057	4.7%	69.9%
6	$6,136,280	1.9%	32.2%	$14,238,849	4.5%	74.4%
7	$4,227,166	1.3%	33.5%	$13,784,436	4.3%	78.7%
8	$4,178,410	1.3%	34.8%	$7,705,847	2.4%	81.1%
9	$3,618,783	1.1%	36.0%	$7,539,983	2.4%	83.5%
10	$3,507,989	1.1%	37.1%	$6,033,195	1.9%	85.4%

Table 3-82 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $19,581,161, or 20.7 percent of the total day-ahead generator credits, compared to 18.3 percent in 2008. The second unit had a 14.1 percent share, which when combined with the top unit was 34.8 percent of the total credits. The top organization in 2009 received 48.9 percent of the day-ahead credits, compared to 41.8 percent in 2008. The top 10 organizations received 92.1 percent of the day-ahead credits.

Table 3-82 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2009

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$19,581,161	20.7%	20.7%	$46,317,856	48.9%	48.9%
2	$13,367,045	14.1%	34.8%	$8,826,849	9.3%	58.2%
3	$9,844,069	10.4%	45.2%	$7,249,218	7.7%	65.9%
4	$3,204,836	3.4%	48.6%	$6,196,701	6.5%	72.4%
5	$3,183,690	3.4%	51.9%	$3,970,211	4.2%	76.6%
6	$1,441,538	1.5%	53.5%	$3,921,590	4.1%	80.8%
7	$1,235,554	1.3%	54.8%	$3,413,069	3.6%	84.4%
8	$1,079,218	1.1%	55.9%	$2,579,206	2.7%	87.1%
9	$1,074,593	1.1%	57.0%	$2,545,188	2.7%	89.8%
10	$1,034,348	1.1%	58.1%	$2,223,899	2.3%	92.1%

Table 3-83 rank orders the top 10 units receiving synchronous condensing credits, and the top 10 organizations receiving synchronous condensing credits. This market remains even more highly concentrated the operating reserve credits overall, as the top organization received 89.4 percent of synchronous condensing credits, down from 96.7 percent in 2008.

Table 3-83 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2009

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$40,271,049	12.7%	12.7%	$104,362,793	32.8%	32.8%
2	$26,582,418	8.4%	21.0%	$53,684,600	16.9%	49.7%
3	$13,129,115	4.1%	25.2%	$30,268,335	9.5%	59.3%
4	$8,972,470	2.8%	28.0%	$18,858,384	5.9%	65.2%
5	$7,153,457	2.3%	30.2%	$15,000,057	4.7%	69.9%
6	$6,136,280	1.9%	32.2%	$14,238,849	4.5%	74.4%
7	$4,227,166	1.3%	33.5%	$13,784,436	4.3%	78.7%
8	$4,178,410	1.3%	34.8%	$7,705,847	2.4%	81.1%
9	$3,618,783	1.1%	36.0%	$7,539,983	2.4%	83.5%
10	$3,507,989	1.1%	37.1%	$6,033,195	1.9%	85.4%

Table 3-84 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 29.3 percent of total credits. The top ten organizations received a total of 86.6 percent of all the balancing generator credits.

Table 3-84 Top 10 units and organizations receiving balancing generator credits: Calendar year 2009

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$26,893,531	14.2%	14.2%	$55,607,771	29.3%	29.3%
2	$8,546,543	4.5%	18.7%	$43,713,256	23.0%	52.3%
3	$6,892,404	3.6%	22.3%	$18,496,966	9.7%	62.1%
4	$6,576,909	3.5%	25.8%	$16,010,493	8.4%	70.5%
5	$5,619,044	3.0%	28.7%	$8,803,268	4.6%	75.2%
6	$3,826,633	2.0%	30.8%	$6,733,375	3.5%	78.7%
7	$3,752,008	2.0%	32.7%	$5,100,022	2.7%	81.4%
8	$3,285,046	1.7%	34.5%	$3,576,306	1.9%	83.3%
9	$2,718,638	1.4%	35.9%	$3,421,873	1.8%	85.1%
10	$2,659,577	1.4%	37.3%	$2,816,285	1.5%	86.6%

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Table 3-85 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 44.6 percent of the total lost opportunity cost credits and 93.1 percent were received by the top 10 organizations.

Table 3-85 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2009

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$2,256,939	7.3%	7.3%	$13,777,592	44.6%	44.6%
2	$2,045,331	6.6%	13.9%	$7,800,058	25.3%	69.9%
3	$1,932,260	6.3%	20.2%	$1,439,186	4.7%	74.5%
4	$1,791,713	5.8%	26.0%	$1,323,636	4.3%	78.8%
5	$1,781,744	5.8%	31.8%	$1,314,648	4.3%	83.1%
6	$1,766,793	5.7%	37.5%	$1,144,495	3.7%	86.8%
7	$1,192,543	3.9%	41.3%	$550,608	1.8%	88.6%
8	$909,480	2.9%	44.3%	$521,262	1.7%	90.2%
9	$843,495	2.7%	47.0%	$505,276	1.6%	91.9%
10	$738,101	2.4%	49.4%	$381,926	1.2%	93.1%

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