SECTION 3 – ENERGY MARKET, PART 2

The PJM Market Monitoring Unit (MMU) analyzed the net revenue performance of PJM Markets, the nature of new investment in capacity in PJM, the definition and existence of scarcity conditions in PJM and the issues associated with operating reserve credits and charges.

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[1]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

- **Phase 2 (2004).** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[4]

- **Phase 3 (2004).** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

1 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

2 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. 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 2005 net revenue indicates that the fixed costs of new peaking and midmerit units were not fully covered, but that the fixed costs of new coal-fired baseload were covered. During the seven-year period 1999 to 2005, the data lead to the conclusion that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower, less volatile Energy Market prices and lower Capacity Market prices.

Existing and Planned Generation

- **PJM Installed Capacity**. During the period January 1 through December 31, 2005, PJM installed capacity grew by approximately 20,100 MW, primarily as a result of the integration of new areas into the PJM markets.

- **PJM Installed Capacity by Fuel Type.** At the end of 2005, PJM installed capacity was about 163,471 MW. Of the total installed capacity, 41.5 percent was coal, 27.5 percent was natural gas, 19.1 percent was nuclear, 7.2 percent was oil, 4.3 percent was hydroelectric and 0.3 percent was solid waste.

- **Generation Fuel Mix.** During 2005, coal was 56.4 percent, nuclear 34.2 percent, natural gas 5.9 percent, oil 1.2 percent, hydroelectric 1.7 percent, solid waste 0.6 percent and wind 0.1 percent of total generation.

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

Scarcity

- **Historical Scarcity Pricing.** Scarcity exists when supply is less than, or equal to, demand where demand includes a level of operating reserves. In PJM, scarcity pricing has resulted under these conditions as the result of the shape of the PJM aggregate supply curve. Scarcity pricing occurred, for example, in the summer of 1999 in PJM.

- **Scarcity in 2005.** In the summer of 2005, the first hot summer since the integrations of Phases 1 through 5, the dynamic in the PJM Energy Market changed. The change was due, in part, to the larger footprint. What had been PJM's entire Energy Market in 1999 was now just a regional part of the market. Units that might have been dispatched in 1999 to meet aggregate PJM load were dispatched in 2005 to resolve constraints associated with bringing lower cost power from the west to east. The result was that rather than units in the eastern part of PJM being dispatched in merit order to meet aggregate demand in the relatively small eastern part of PJM, the units were dispatched out of merit order to solve local constraints. The result, in turn, was that there was not a market mechanism to ensure that prices increased to reflect the scarcity conditions that existed on two occasions.

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, 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. 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 2005.** Operating reserve charges were significantly higher in 2005 than in prior years. The reasons for the observed increase in the operating reserve rate include increased fuel costs, unexpected transmission outages, unanticipated fluctuations in interchange transactions levels and market power.

Conclusion

Wholesale electric power markets, apparently without exception, are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability, typically measured as an acceptable loss of load probability level. This level of reliability is enforced through a requirement to maintain a target level of installed or unforced capacity, which, based on planning models, is considered to be a level that will produce the desired loss of load probability. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full requirements contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The impact of having capacity in excess of the equilibrium level likely to result from the operation of an energy market alone is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electricity market design.

While net revenue in PJM has been sufficient to cover the costs of new peaking units in some years and was sufficient to cover the costs of a new coal plant in 2005, net revenue has been below the level required to cover the full costs of new generation investment for several years and below that level on average for all unit types for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM Markets. However, it is also the case that there are some units in PJM, needed for reliability, that have revenues that are not adequate to cover annual going forward costs and that their owners, therefore, wish to retire. This suggests that market price signals and reliability needs are not fully synchronized.

The issue is how to understand this phenomenon and how to address it within the context of competitive markets. The level of net revenues in PJM Markets is not the result of the $1,000 per MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly value the resources needed to provide for reliability.

A capacity market is a formal market-based mechanism used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. Ideally, a capacity market would include a mechanism for equilibrating energy and capacity market revenues such that, in equilibrium, generators receive a market-based return for investing in capacity from all markets taken together. A capacity market is also an explicit mechanism for valuing capacity and is preferable to non market and non-transparent mechanisms for that reason.

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

A market design cannot be deemed truly successful until it results in the retirement and replacement of a significant portion of the existing investment in generating assets, based on incentives endogenous to the market design. The net revenue performance of the markets over six years illustrates that additional market modifications are necessary if PJM is to pass the ultimate test of a market, the successful provision of long-term incentives to invest.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM Markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included here because the analysis is based on economic dispatch in the PJM model.[5] Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity Markets and the Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after variable costs have been subtracted from gross revenue, to cover fixed costs including a return on investment, depreciation, taxes and fixed operations and maintenance expenses.

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than based on the analysis of actual net revenues for actual units operating in PJM.

Table 3-1 illustrates the relationship between generator variable cost and net revenue from the PJM Energy Market alone for the years 1999 through 2005.

Table 3-1 - PJM Energy Market net revenue [By unit marginal cost (Dollars per installed MW-year)]: Calendar years 1999 to 2005

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

5 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over the day of operation. The PJM model also ensures that generators are compensated for startup and no-load costs when they are dispatched based on marginal costs or on their offer price.

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

The net revenue analysis includes a natural gas-fired CT, a two-on-one natural gas-fired CC plant and a CP steam plant as the new entry technologies in order to provide a relatively complete representation of entry conditions. Two dispatch scenarios are analyzed for each new entry technology.

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

The net revenue calculations under perfect dispatch are an approximate measure, generally representing an upper bound of the markets' direct contribution to generator fixed costs. The Energy Market net revenue curve does not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC steam plant, a two-hour hot status notification plus startup time for a summer weekday could prevent a unit from running during two profitable hours in the afternoon peak and two more profitable hours in the evening peak separated by two unprofitable hours, or could result in reduced net revenues from the unprofitable hours.[6] The actual impact depends on the relationship between locational marginal price (LMP) and the operating costs of the unit. Likewise, a CP steam plant with an eight-hour cold status notification plus startup time could run overnight during unprofitable hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[7] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all profitable hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the real-time price, e.g. a forward price.

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

6 A two-hour hot start, including a notification period, is consistent with the CC technology.
7 An eight-hour cold status notification plus startup is consistent with the CP technology.

Energy Market Net Revenue

The Energy Market revenues in Table 3-1 reflect net Energy Market revenues from all hours during 1999 to 2005 when the average PJM hourly locational market price exceeded the identified marginal cost of generation. The table includes the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[8] For example, during 2005, if a unit had marginal costs (fuel plus variable operations and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2005, adjusted for forced outages, it would have received $241,977 per installed MW-year in net revenue from the Energy Market alone.

Figure 3-1 displays the information from Table 3-1. As Figure 3-1 illustrates, the Energy Market net revenue curve was higher in 2005 for every level of unit marginal costs compared to 2004. The 2005 net revenues for units with marginal costs equal to, or less than, $80 were higher than for any year since PJM introduced markets in 1999.

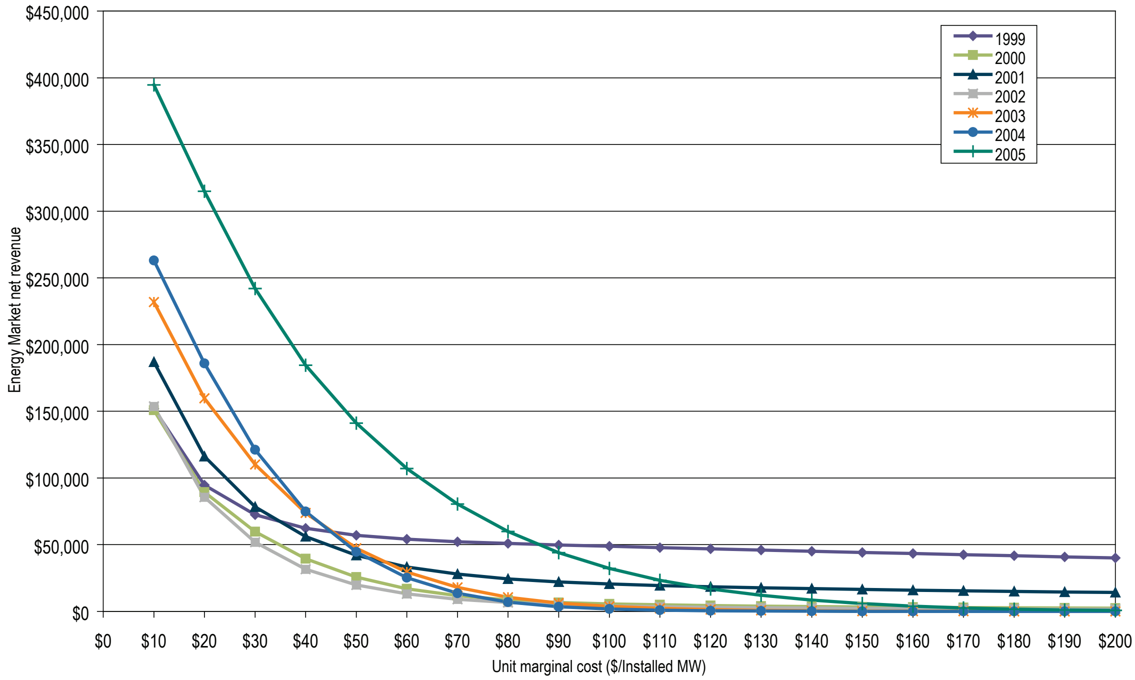
The increase in 2005 net energy revenue compared to 2004 is the result of changes in the frequency distribution of energy prices. In 2005, prices were greater than, or equal to, $30 more frequently than in any other year dating back to 1999. In 1999, LMP was greater than or equal to $30 per MWh during 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 and 81 percent in 2005.

The distribution of prices reflects a number of factors including load levels and fuel costs. An efficient CT could have produced energy at an average cost of $30 in 1999, but $120 in 2005. An efficient CC could have produced energy at an average cost of $20 in 1999, but $85 in 2005. An efficient CP could have produced energy at an average cost of $20 in 1999, but $30 in 2005.

The 2005 load-weighted, average LMP for the PJM system was $63.46 per MWh compared to $44.34 in 2004. There were no price spikes in 2005. The system average hourly LMP exceeded $200 for 35 hours with the maximum LMP at $286.86.

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

Figure 3-1 - PJM Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2005



Differences in the shape and position of net revenue curves for the six years result from different distributions of Energy Market prices. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[9] Energy Market revenues for 2005 are significantly higher for units with marginal costs up to and including $80 than for any other year, primarily because the higher fuel costs of gas-fired marginal units resulted in higher prices and thus higher energy revenues for generators with lower fuel cost.

Capacity Market Net Revenue

Generators receive revenues from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. In 2005, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Markets of $6.12 per unforced MW-day, or $2,089 per MW-year of installed capacity. This is the lowest level of Capacity Market revenues since the opening of PJM Markets in 1999.

The PJM Capacity Market price used for net revenue calculations is the composite Capacity Market, excluding ComEd through May 31, 2005, and the entire PJM footprint from June 1, 2005, onward. The corresponding annual Capacity Market prices are presented in Table 3-2.

9 See Section 2, "Energy Market, Part 1," at "Load and LMP," for detailed data on the annual distribution of prices.

Table 3-2 - PJM's average annual Capacity Market price: Calendar years 1999 to 2005

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

Ancillary Service and Operating Reserve Net Revenue

Generators also receive revenue from the sale of ancillary services, including those from the Spinning Reserve and Regulation Markets as well as black start and reactive services. Aggregate ancillary service revenues were $5,135 per installed MW-year in 2005, the highest level since the introduction of PJM Markets in 1999. (See Table 3-3.) While actual, generator-specific ancillary service revenues vary with generator technology, ancillary service revenues are expressed here in terms of a system average per installed MW. Theoretical net revenue calculations, addressed later in this section, use more detailed, technology-specific ancillary service estimates.

Table 3-3 - System average ancillary service revenues: Calendar years 1999 to 2005

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

Although not included in the net revenue analyses, generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $3,600 per installed MW-year in 2004 and were about $3,800 per installed MW-year in 2005. These payments are designed, in part, to ensure that generators are paid enough to cover their offers, including startup and no-load costs, when scheduled by PJM and that they are not required to run at a loss.

New Entrant Net Revenue Analysis

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

Net revenue calculations include the use of actual hourly ambient air temperature[10] and river water cooling temperature[11] and the effect of each, as applicable, on plant heat rates[12] and generator output for each of the three plant configurations.[13] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air and river condition variations.[14] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly to adjust for changes in energy production. For purposes of determining the amount of capacity that could be sold in the Capacity Market, the available capacity of each plant type was calculated based on actual ambient conditions at the hour of each annual peak load, consistent with PJM rules for determining available capacity. Available capacity was then adjusted downward by the actual class average forced outage rate for each generator type in order to obtain the level of unforced capacity available for sale in PJM capacity auctions, by plant type.

NO_x and SO_2 credit 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 credit costs were obtained from actual historical daily spot cash prices for the prompt year.[15] NO_x credit costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 credit costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[16] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a 15-continuous-day, planned annual outage in the fall season.

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

11 Hourly river water conditions represent the Reedy Island Jetty Gauge station located on the Delaware River. Data obtained from U.S. Department of the Interior – U.S. Geological Survey < http://nwis.waterdata.usgs.gov/pa/nwis/qwdata?site_no=01482800>.

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

13 Strategic Energy Services, Inc.

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

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

16 Outage figures obtained from the PJM eGADS database.

Variable operations and maintenance (VOM) expenses were estimated to be $5.00 per MWh for the CT plant, $1.50 per MWh for the CC plant and $2.00 per MWh for the CP plant. These estimates were provided by a consultant to PJM and are based on quoted, third-party contract prices.[17] The VOM expenses for the CT and CC plants include accrual of anticipated routine major overhaul expenses.[18] The burner tip fuel cost for natural gas is from published[19] commodity daily cash prices, with a basis adjustment for transportation costs. Coal burner tip cost was developed from the published prompt month price,[20] adjusted for rail transportation cost. The average burner tip fuel prices are shown in Table 3-4.

Ancillary service revenues for the provision of spinning reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 spinning reserve in PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 spinning reserve, but the 2005 Tier 1 revenues were minimal. 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. Ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $7.50, per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost of service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. For CTs, the calculated rate is $2,248 per installed MW-year; for CCs, the calculated rate is $3,155 per installed MW-year and for CPs, the calculated rate is $1,692 per installed MW-year.[21]

Table 3-4 - Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2005

	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

17 Strategic Energy Services, Inc.

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

19 Gas daily cash prices obtained from Platt's.

20 Coal prompt prices obtained from Energy Argus for 1999 to 2004 and from Platt's for 2005.

21 The CT plant reactive revenues are based on 22 recent FERC filings for CT reactive costs. The CC plant revenues are based on 18 recent FERC filings for CC reactive costs, and the CP plant revenues are based on five recent FERC filings for CP reactive costs. These figures have been updated from those reported in the *2004 State of the Market Report* to include the large number of generators integrated into PJM from the AEP, DAY, DLCO and Dominion Control Zones as well as new generation in existing zones.

The perfect dispatch scenario total net revenues for 1999 to 2005 are shown in Table 3-5, Table 3-6 and Table 3-7 for the new entrant CT, CC and CP facilities, respectively.

Table 3-5 - New entrant gas-fired CT (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005

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

Table 3-6 - New entrant gas-fired CC (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005

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

Table 3-7 - New entrant CP (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005

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

To demonstrate the sensitivity of the CT Energy Market net revenue results to the assumption of perfect dispatch with no operating constraints, Energy Market net revenues were calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average PJM real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[22] for at least two hours during each four-hour block.[23] The blocks are dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The calculations account for operating reserves based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 3-5 results.

A comparison of the results is shown in Table 3-8, where the first column in Table 3-8 is the perfect economic dispatch Energy Market net revenue results from Table 3-5. For the seven-year period, the average Energy Market net revenue under the perfect economic dispatch scenario was about $25,300 per installed MW-year while the seven-year average for the peak-hour dispatch scenario is about $17,000 per installed MW-year or about a 33 percent reduction in Energy Market net revenues. Additional, more complex dispatch scenarios were analyzed for the CT plant; however, the resultant effect on Energy Market net revenue was about the same as the results of the peak-hour dispatch scenario versus the perfect economic dispatch scenario.

Table 3-8 - Energy Market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2005

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
1999	$62,065	$55,612	($6,452)	(10.4%)
2000	$16,476	$8,498	($7,978)	(48.4%)
2001	$39,269	$30,254	($9,015)	(23.0%)
2002	$23,232	$14,496	($8,736)	(37.6%)
2003	$12,154	$2,763	($9,390)	(77.3%)
2004	$8,063	$919	($7,144)	(88.6%)
2005	$15,741	$6,141	($9,600)	(61.0%)
Average	$25,286	$16,955	($8,331)	(32.9%)

To demonstrate the sensitivity of the CC Energy Market net revenue results to the assumption of perfect dispatch with no operating constraints, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the average PJM real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[24] for at least eight hours during that time period. If there were not eight economic hours in any given day, then the CC was not dispatched. The calculations account for operating reserves 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 costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 3-6 results.

22 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platt's fuel prices. Per PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM Settlements. No-load costs are included in the heat rate.

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

24 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platt's fuel prices. Per PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005), startup and shutdown station power consumption costs were obtained from the Station Service rates published quarterly by PJM Settlements. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour and off for every uneconomic hour; therefore there is a single offer point and no offer curve.

A comparison of the results is shown in Table 3-9 where the first column in Table 3-9 is the perfect economic dispatch Energy Market net revenue results from Table 3-6. For the seven-year period, the average Energy Market net revenue under the perfect economic dispatch scenario was about $60,200 per installed MW-year while the seven-year average for the peak-hour dispatch scenario is about $41,200 per installed MW-year or about a 32 percent reduction in Energy Market net revenues. Additional, more complex dispatch scenarios were analyzed for the CC plant; however, the resultant effect on Energy Market net revenue was about the same as the results of the peak-hour dispatch scenario versus the perfect economic dispatch scenario.

Table 3-9 - Energy Market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2005

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
1999	$89,600	$80,546	($9,055)	(10.1%)
2000	$42,647	$24,794	($17,854)	(41.9%)
2001	$68,949	$54,206	($14,743)	(21.4%)
2002	$51,639	$38,625	($13,015)	(25.2%)
2003	$50,346	$27,155	($23,191)	(46.1%)
2004	$49,600	$27,389	($22,211)	(44.8%)
2005	$68,308	$35,608	($32,700)	(47.9%)
Average	$60,156	$41,189	($18,967)	(31.5%)

To demonstrate the sensitivity of the CP Energy Market net revenue results to the assumption of perfect dispatch with no operating constraints, Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for full operating reserves, when applicable, since the assumed operation is under the direction of PJM operations. The additional dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 3-7 results.[25]

A comparison of the results is shown in Table 3-10 where the first column in Table 3-10 is the perfect economic dispatch Energy Market net revenue results from Table 3-7. For the seven-year period, the average, Energy Market net revenue under the perfect economic dispatch scenario was about $136,700 per installed MW-year while the seven-year average for the available dispatch scenario is about $128,700 per installed MW-year or about a 6 percent reduction in Energy Market net revenues. The two scenarios are provided to present a reasonable bound of energy net revenues for a new entrant CP.

25 No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, and at off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

Table 3-10 - Energy Market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2005

	Perfect Economic Dispatch	All Available Hour Economic	Difference	Percent Difference
1999	$101,011	$92,935	($8,076)	(8.0%)
2000	$112,202	$108,624	($3,578)	(3.2%)
2001	$106,866	$95,361	($11,505)	(10.8%)
2002	$101,345	$96,828	($4,517)	(4.5%)
2003	$166,540	$159,912	($6,628)	(4.0%)
2004	$136,280	$124,497	($11,783)	(8.6%)
2005	$232,351	$222,911	($9,440)	(4.1%)
Average	$136,656	$128,724	($7,932)	(5.8%)

Net Revenue Adequacy

To put the net revenue results in perspective, the first operating year's annual fixed costs for the assumed new entrant CT plant configuration would be about $61,700 per installed[26] MW-year or about $72,200 per installed MW-year if levelized over the 20-year life of the project.[27] The first operating year's annual fixed cost for the assumed CC and CP plant configurations would be about $80,000 per installed MW-year and $178,000[28] per installed MW-year, respectively. The levelized 20-year operating annual costs for the CC and CP plants would be about $93,500 per installed MW-year and $208,200 per installed MW-year, respectively. A tabulation of the first operating year and 20-year operating life levelized costs is shown in Table 3-11.[29]

Table 3-11 - New entrant first-year and 20-year levelized fixed costs [By plant type (Dollars per installed MW-year)]

	First-Year Fixed Cost	20-Year Levelized Fixed Cost
CT	$61,726	$72,207
CC	$79,969	$93,549
CP	$178,019	$208,247

In 2005, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CT were approximately $20,000 per installed MW-year. The associated operating costs were between $110 and $120 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $9.73 per MBtu and a VOM rate of $5 per MWh.[30] The resulting net revenue stream would not have covered the fixed costs of a new CT if it ran during all profitable hours.

26 Installed capacity at 92 degrees F.

27 This is the same analysis performed for PJM by Strategic Energy Services, Inc. during 2004 in the development of the cost of new entry for the reliability pricing model (RPM). After evaluation for current market conditions, there is little to no change in the project cost, and as such the 2004 study results are reasonable for 2005 analysis. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target equity internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 20-year modified accelerated cost-recovery schedule (MACRS). A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

28 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2005.

29 The figures in Table 3-11 represent the annual cost for the first year of operation. For example, the $61,726 per installed MW-year figure represents the annual cost of the CT for the first operational year of the plant. Assuming a two-year construction period, the cost for the first year of construction would be $58,752 per installed MW-year.

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

In 2005, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CC were approximately $73,500 per installed MW-year. The associated operating costs were between $75 and $85 per MWh, based on a design heat rate of 7,500 Btu per kWh, average daily delivered natural gas prices of $9.73 per MBtu and a VOM rate of $1.50 per MWh. The resulting net revenue stream would not have covered the fixed costs of the CC plant if it ran during all profitable hours.

In 2005, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CP would have been approximately $237,900 per installed MW-year. The associated operating costs would have ranged between $30 and $35 per MWh,[31] based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.88 per MBtu and a VOM rate of $2 per MWh. This revenue stream would have covered the fixed costs of a CP plant if it ran during all profitable hours. In 1999 and 2001, the net revenue shown for the CT and CC plants was sufficient to cover the first year's fixed costs of $61,700 per installed MW-year and $80,000 per installed MW-year, respectively. In 2000 and 2002 through 2005, there was, however, a revenue shortfall for both plant types. For the CP, 2005 was the only year with sufficient net revenues to cover the first year's fixed cost of $178,000 per installed MW-year.

Under the perfect economic dispatch scenario, the seven-year net revenue averaged $40,700 per installed MW-year for a new entrant CT plant, $76,000 per installed MW-year for a new entrant CC plant and $154,400 per installed MW-year for a new entrant CP plant. Thus, under perfect economic dispatch over the seven-year period, the average net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

Table 3-12 - CT 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2005

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$80,990	112%	$74,537	103%
2000	$72,207	$38,924	54%	$30,946	43%
2001	$72,207	$72,477	100%	$63,462	88%
2002	$72,207	$36,996	51%	$28,260	39%
2003	$72,207	$19,956	28%	$10,565	15%
2004	$72,207	$15,687	22%	$8,543	12%
2005	$72,207	$20,037	28%	$10,437	14%
Average	$72,207	$40,724	56%	$32,393	45%

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

Table 3-13 - CC 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2005

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$109,754	117%	$100,700	108%
2000	$93,549	$65,445	70%	$47,592	51%
2001	$93,549	$101,413	108%	$86,670	93%
2002	$93,549	$65,286	70%	$52,272	56%
2003	$93,549	$58,782	63%	$35,591	38%
2004	$93,549	$57,996	62%	$35,785	38%
2005	$93,549	$73,517	79%	$40,817	44%
Average	$93,549	$76,028	81%	$57,061	61%

Table 3-14 - CP 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2005

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$126,097	61%	$118,021	57%
2000	$208,247	$138,141	66%	$134,563	65%
2001	$208,247	$140,776	68%	$129,271	62%
2002	$208,247	$116,648	56%	$112,131	54%
2003	$208,247	$176,138	85%	$169,510	81%
2004	$208,247	$144,908	70%	$133,125	64%
2005	$208,247	$237,870	114%	$228,430	110%
Average	$208,247	$154,368	74%	$146,436	70%

Table 3-12 through Table 3-14 show net revenues under the perfect dispatch and economic scenarios compared to the 20-year levelized fixed costs of each plant type. During the seven-year period from 1999 to 2005, the CT plant recovered 56 percent of the 20-year levelized fixed costs under the perfect dispatch scenario and 45 percent under the economic scenario. During that same period the CC plant recovered 81 percent of the fixed costs under the perfect dispatch scenario and 61 percent under the economic and the CP recovered 74 percent of the fixed costs under the perfect dispatch scenario and 70 percent under the economic dispatch scenario.

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of 2005 net revenue indicates that the fixed costs of new peaking and midmerit units were not fully covered, but that the fixed costs of new coal-fired baseload were covered. During the seven-year period 1999 to 2005, the data lead to the conclusion that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower, less volatile Energy Market prices and lower Capacity Market prices.

Shortfalls in net revenue affect the returns earned by new generating units. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on equity for an investment in a new generating unit. The return on equity was calculated for a range of 20-year levelized net revenue streams, assuming the 20-year levelized fixed costs from Table 3-11. Levelized net revenues were modified and the return on equity calculated. A $5,000 per MW-year sensitivity was used for the CT and CC and a $10,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-15.[32]

Table 3-15 - Return on equity sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$77,207	14.0%	$98,549	13.5%	$218,247	13.3%
Base Case	$72,207	12.0%	$93,549	12.0%	$208,247	12.0%
Sensitivity 2	$67,207	9.9%	$88,549	10.4%	$198,247	10.7%
Sensitivity 3	$62,207	7.7%	$83,549	8.8%	$188,247	9.3%
Sensitivity 4	$57,207	5.2%	$78,549	7.1%	$178,247	7.9%
Sensitivity 5	$52,207	2.3%	$73,549	5.3%	$168,247	6.5%
Sensitivity 6	$47,207	(1.6%)	$68,549	3.3%	$158,247	4.9%

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

32 This table is based on the same analysis performed for PJM by Strategic Energy Services, Inc. during 2004 in the development of the cost of new entry for the RPM. After evaluation for current market conditions, there is little to no change in the project cost, and as such the 2004 study results are reasonable for 2005 analysis. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target equity internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 20-year modified accelerated cost-recovery schedule (MACRS). A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Existing and Planned Generation

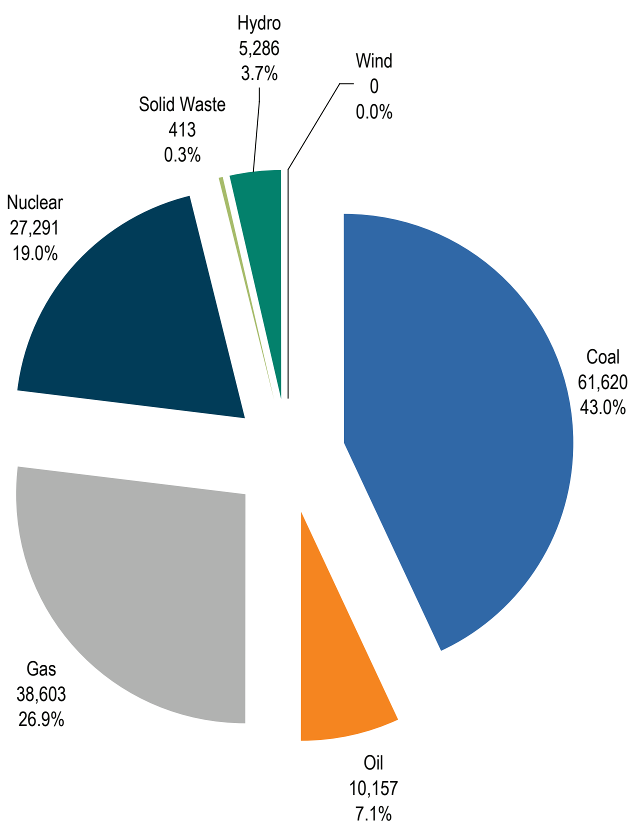
Installed Capacity and Fuel Mix at December 31, 2005

During calendar year 2005, primarily as a result of the integrations, PJM installed capacity increased from 143,370 MW on January 1 to 163,471 MW on December 31 and the fuel mix shifted slightly.

Installed Capacity

On January 1, 2005, PJM installed capacity[33] was 143,370 MW,[34] with a fuel mix that was 43.0 percent coal, 26.9 percent natural gas, 19.0 percent nuclear, 7.1 percent oil, 3.7 percent hydroelectric and 0.3 percent solid waste.[35] (See Figure 3-2.) This includes the newly integrated DLCO Control Zone as of January 1, 2005.

Figure 3-2 - PJM capacity (By fuel source): At January 1, 2005

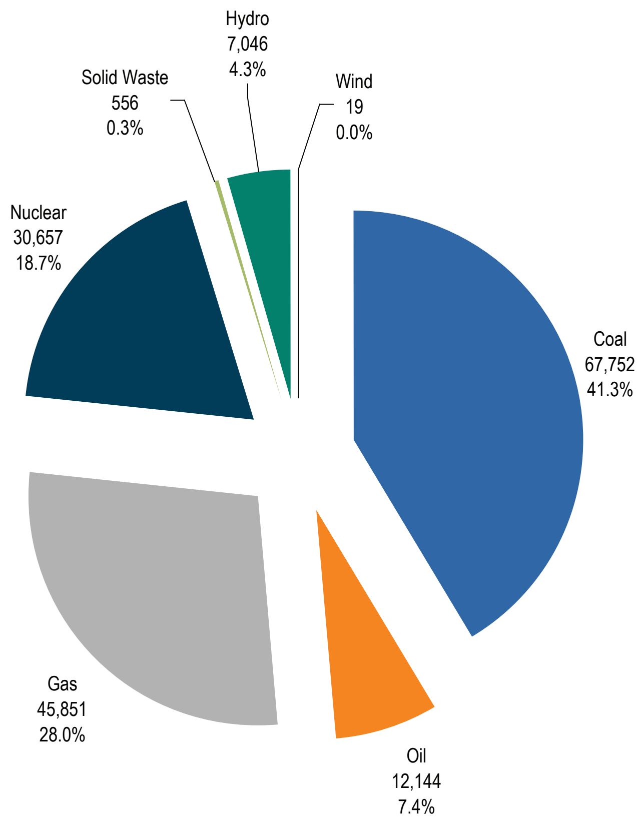


33 Installed capacity includes net capacity imports and exports and can vary on a daily basis.
34 These capacity values include the ComEd Control Zone.
35 Values in percent may not add to 100 because of rounding.

During Phase 4, unit retirements, rating changes and changes in capacity imports and exports resulted in an installed capacity increase of 1,218 MW. On April 30, 2005, installed capacity was 144,588 MW.

With the integration of Dominion on May 1, 2005, installed capacity increased by 19,436 MW to 164,024 MW, a 13.4 percent increase in total PJM capacity over the April 30 level. The Dominion Control Zone had proportionally more gas and hydroelectric generating capability and less coal and nuclear generating capability than PJM had prior to the Phase 5 integration. As a result, the gas share of total PJM installed capacity rose by 0.4 percent to 28.0 percent; the hydroelectric share increased by 0.9 percent to 4.3 percent and the oil share increased by 0.4 percent to 7.4 percent, while the coal share of capacity fell by 2.0 percent to 41.3 percent and the nuclear share declined 0.2 percent to 18.7 percent.[36] (See Figure 3-3.)

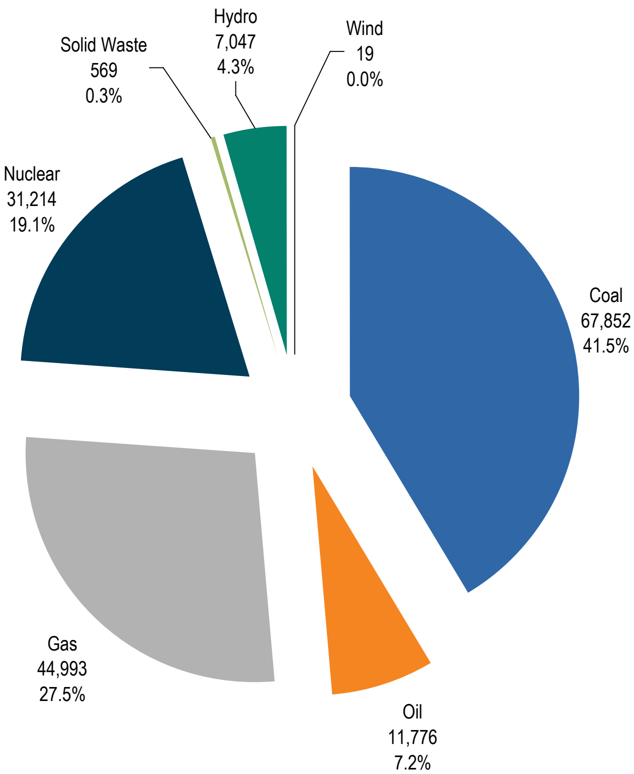
Figure 3-3 - PJM capacity (By fuel source): At May 1, 2005



36 Values in percent may not add to 100 because of rounding.

On December 31, 2005, PJM installed capacity was about 163,471 MW. Of the total installed capacity, 67,852 MW, or 41.5 percent, was coal; 44,993 MW, or 27.5 percent, was natural gas; 31,214 MW, or 19.1 percent, was nuclear; 11,776 MW, or 7.2 percent, was oil; 7,047 MW, or 4.3 percent, was hydroelectric; 569 MW, or 0.3 percent, was solid waste; and 19 MW, or 0.0 percent, was wind.[37] (See Figure 3-4.)

Figure 3-4 - PJM capacity (By fuel source): At December 31, 2005

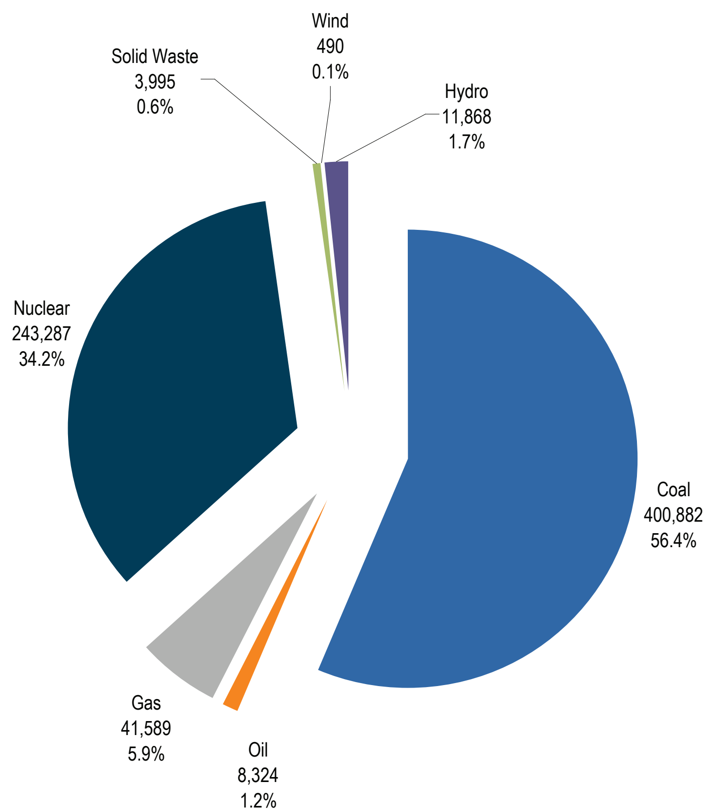


37 Although wind-based resources accounted for only 19 MW of the installed capacity in PJM on this date, in actuality, this value represents only 20 percent of wind capability in PJM. PJM administratively reduces the capabilities of all wind generators by 80 percent when determining the system installed capacity because they cannot be dispatched on demand.

Output by Fuel Source

In calendar year 2005, coal and nuclear units generated 90.6 percent of the total electricity. Coal was 56.4 percent, nuclear 34.2 percent, natural gas 5.9 percent, oil 1.2 percent, hydroelectric 1.7 percent, solid waste 0.6 percent and wind 0.1 percent of total generation.[38] (See Figure 3-5.)

Figure 3-5 - PJM generation [By fuel source (In GWh)]: Calendar year 2005



38 Values may not add to 100 percent due to rounding.

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 2005, about 24,300 MW of capacity were in generation request queues for construction through 2010, compared to an average installed capacity of 146,869 MW in 2005 and a year-end installed capacity of 163,471 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity. (See Table 3-16 .)

Table 3-16 - Year-to-year capacity additions: Calendar years 2000 through 2005

	Capacity Additions (MW)
2000	504
2001	1,068
2002	3,800
2003	3,521
2004	1,925
2005	777

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

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from April 1997 through March 1999; Queue B was open from April 1999 through September 1999 and Queue C opened in October 1999. After Queue C, a new queue was opened every six months. Queue P is currently active.

Capacity in generation request queues (See Table 3-17.) for the six-year period beginning in 2005 and ending in 2010 increased by approximately 12,100 MW from 15,500 MW in 2004 to 27,600 MW in 2005.[39, 40] Queued capacity scheduled for service in 2005 decreased from 4,906 MW to 3,151 MW, or 36 percent. Queued capacity scheduled for service in 2006 increased from 5,250 MW to 5,931 MW, or 13 percent. Capacity in the queues for the years 2007 and 2008 also increased in 2005 over 2004. Queued capacity scheduled for service in 2010 indicates that capacity is being planned further in the future than last year. In 2004, no projects were in queues projected to enter service later than 2008.

Table 3-18 shows the amount of capacity currently active, in service, under construction or withdrawn for each queue since the beginning of the regional transmission expansion planning (RTEP) process and the total amount of capacity that had been included in each queue.

Table 3-17 - Queue comparison (In MW): Calendar year 2004 vs. 2005

	MW in the Queue 2004	MW in the Queue 2005	Year-to-Year Change (MW)	Year-to-Year Change
2005	4,906	3,151	(1,755)	(36%)
2006	5,250	5,931	681	13%
2007	1,051	5,425	4,374	416%
2008	4,263	6,462	2,199	52%
2009	0	1,735	1,735	NA
2010	0	4,875	4,875	NA
Total	15,470	27,579	12,109	NA

39 See the *2004 State of the Market Report* (March 8, 2005), pp. 84-85, for the queues in 2004.
40 The 27,600 MW includes generation with scheduled in service dates in 2005 and earlier years net of generation that is in service earlier than scheduled.

Table 3-18 - Capacity in PJM queues (In MW): At December 31, 2005

Queue	Active	In Service	Under Construction	Withdrawn	Total
A Expired 31-Mar-98	0	8,086	750	18,145	26,981
B Expired 31-Mar-99	0	4,306	0	16,024	20,330
C Expired 30-Sep-99	0	0	436	4,104	4,540
D Expired 31-Mar-00	0	807	0	7,564	8,371
E Expired 30-Sep-00	0	779	0	17,512	18,291
F Expired 31-Mar-01	0	16	0	3,093	3,109
G Expired 30-Sep-01	640	340	525	21,893	23,398
H Expired 31-Mar-02	0	56	400	8,424	8,880
I Expired 30-Sep-02	105	38	8	4,863	5,014
J Expired 31-Mar-03	200	14	22	707	943
K Expired 30-Sep-03	55	221	468	2,033	2,777
L Expired 31-Mar-04	550	38	317	3,383	4,288
M Expired 30-Sep-04	1,354	20	5	2,934	4,313
N Expired 31-Mar-05	5,266	1,814	4	3,884	10,968
O Expired 30-Sep-05	7,002	81	3	662	7,748
P Expired 31-Mar-06	6,235	0	0	0	6,235
Total	21,407	16,616	2,938	115,225	156,186

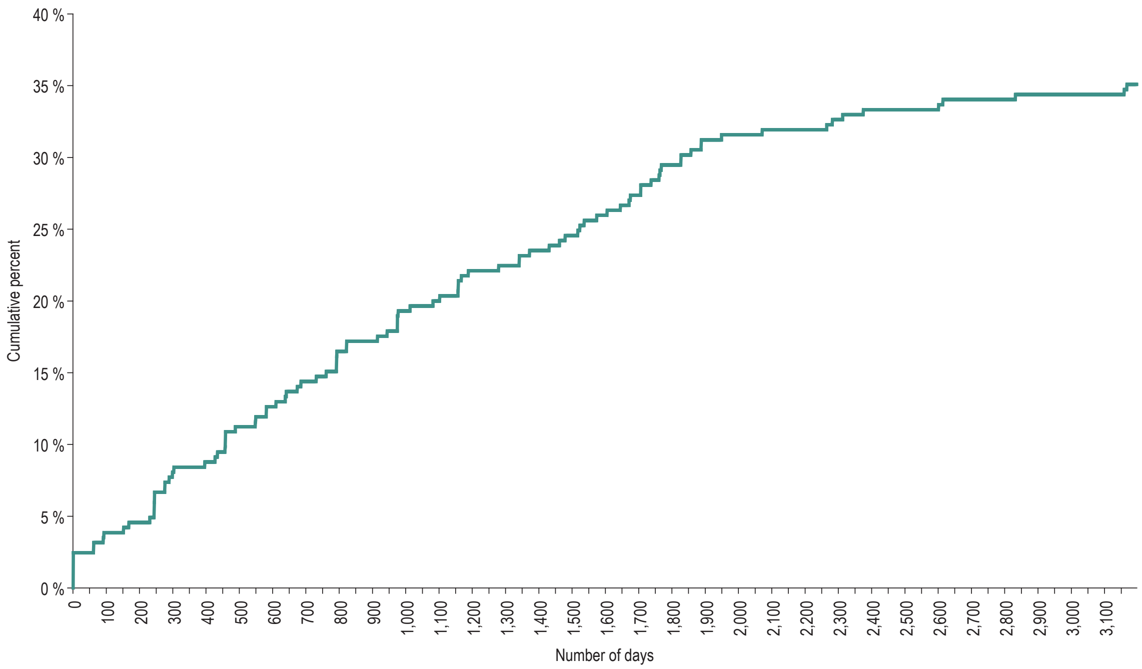
The data presented in Table 3-18 show that 75 percent of total in-service capacity from all the queues was from queues A and B and an additional 10 percent was from queues C, D and E. The data presented in Table 3-19 show that for successful projects there is an average time of 1,056 days (2.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 809 days (2.2 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

Table 3-19 - Average project queue time: At December 31, 2005

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In Service	1,056	802	0	3,196
Under Construction	1,210	688	278	3,200
Withdrawn	809	540	11	2,542
Active	364	294	95	1,739

Figure 3-6 shows the cumulative probability of completion of RTEP projects. Based on the data presented in Figure 3-6, 25 percent or more of the projects in the queues are completed by the time they have been in the queue 1,523 days. Likewise if a project has been resident in the queues for more than 3,167 days (total days to date), the probability that it will have been completed is 35 percent.

Figure 3-6 - RTEP project completion probability as function of days in queue



Distribution of Units in the Queues

Table 3-21 shows the RTEP projects under construction or active as of December 31, 2005, by unit type and control zone. Most (98 percent of the MW) of the steam projects (predominantly coal) are in the Western Region control zones (AEP, AP and ComEd). Most (64 percent of the MW) of the CC projects are in the Mid-Atlantic Region control zones (PECO, PSEG, AECO and JCPL). Wind projects are primarily in the AP, ComEd, PENELEC and PPL Control Zones. Wind projects account for approximately 8,700 MW of capacity or 36 percent of the capacity in the queues.[41]

41 Since wind resources cannot be dispatched on demand, PJM rules require that the unforced capacity of these resources be derated by 80 percent until actual generation data are available. The derating of wind resources means that only 17,400 MW of capacity are effectively in the queue of the 24,300 MW of generation currently active in the queues.

Table 3-20 - Existing PJM capacity [By zone and unit type (In MW)]

	Combined Cycle	Combustion Turbine	Diesel	Hyrdoelectric	Nuclear	Pumped Storage	Steam	Total
AECO	155	547	8	0	0	0	1,108	1,818
AEP	4,275	3,159	0	438	2,093	585	22,200	32,750
AP	1,129	1,202	43	80	0	0	7,879	10,333
BGE	0	872	0	0	1,735	0	2,793	5,400
ComEd	1,790	6,928	18	0	10,336	0	9,892	28,964
DAY	0	1,315	54	0	0	0	4,452	5,821
Dominion	3,369	3,226	105	562	3,432	3,606	8,162	22,462
DPL	1,088	705	85	0	0	0	1,882	3,760
DLCO	268	45	0	0	1,630	0	1,040	2,983
JCPL	1,677	1,226	0	0	619	400	10	3,932
MetEd	1,523	408	0	19	786	0	819	3,555
PECO	2,499	1,507	11	548	4,492	1,070	2,022	12,149
PENELEC	0	337	46	90	0	405	6,787	7,665
PEPCO	230	1,333	2	0	0	0	4,781	6,346
PPL	1,674	613	24	568	2,289	0	5,850	11,018
PSEG	2,022	2,920	15	11	3,353	0	3,003	11,324
Total	21,699	26,343	411	2,316	30,765	6,066	82,680	170,280

Table 3-20 shows existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across all control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources now in the queue (Table 3-21) and the location of units likely to retire. In the east, the capacity mix is likely to shift to more natural gas-fired CC and CT capacity. In the west, continued reliance on steam (mainly coal) seems likely.

Table 3-21 - Capacity additions in active or under-construction queues (In MW): At December 31, 2005

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Steam	Wind	Total
AECO	966	122	2	0	0	8	1,098
AEP	634	179	0	147	5,560	0	6,520
AP	640	0	23	0	1,122	1,451	3,236
BGE	0	0	5	0	0	0	5
ComEd	0	0	0	0	600	5,309	5,909
DAY	0	0	0	0	0	48	48
Dominion	1,275	0	29	431	0	0	1,735
DPL	0	0	13	0	1	0	14
JCPL	0	0	14	0	0	0	14
PECO	1,301	0	2	0	0	0	1,303
PENELEC	0	0	0	0	125	1,295	1,420
PEPCO	0	14	0	0	0	0	14
PPL	0	0	53	0	0	555	608
PSEG	2,351	55	7	0	0	11	2,424
Total	7,167	370	148	578	7,408	8,677	24,348

Table 3-22 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 50 percent of all current MW, steam units over 50 years of age comprise 87 percent of all MW over 50 years old and virtually 100 percent of such MW if run of river hydroelectric is excluded from the total. Steam units over 40 years of age comprise 89 percent of all such MW and 97 percent without run of river hydroelectric. Approximately 30 percent of steam units over 40 years old are located in the eastern PJM control zones.

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 east are replaced by units burning natural gas. Table 3-21 shows that in the eastern control zones, gas consuming unit types (CC and CT facilities) dominate the capacity additions.

Table 3-22 - PJM capacity age (In MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Run of River Hydroelectric	Nuclear	Pumped Storage Hydroelectric	Steam	Total
Less than 10	16,642	17,233	25	54	0	0	1,612	35,566
10 to 20	3,637	2,700	68	124	8,646	0	6,503	21,678
20 to 30	90	16	47	172	12,578	2,751	14,827	30,481
30 to 40	466	7,647	174	30	10,584	1,715	40,428	61,044
40 to 50	675	168	31	535	0	640	17,459	19,508
50 to 60	0	0	6	354	0	0	8,314	8,674
60 to 70	0	0	0	127	0	0	222	349
70 to 80	0	0	0	623	0	0	0	623
80 to 90	0	0	0	61	0	0	0	61
90 to 100	0	0	0	127	0	0	0	127
100 and over	0	0	0	29	0	0	0	29
Total	21,510	27,764	351	2,236	31,808	5,106	89,365	178,140

Table 3-23 shows the effect that the new generation in the queues will have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age will have retired by 2010. Nearly 50 percent of eastern generation will be from CC and CT generators, a 25 percent increase from today. Accounting for the fact that about 10 percent of steam units over 40 years old are gas-fired, the result will be an increase in the proportion of gas-fired capacity in the east from about 34 percent to about 43 percent.

Table 3-23 - Comparison of generators 40 years and older with slated capacity additions (In MW): Through 2010

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators All Ages	Percent of Area Total	Additional Capability through 2010	Estimated Capacity 2010	Percent of Area Total
East	Combined Cycle	675	7.3 %	10,638	20.7 %	4,618	14,581	29.8 %
	Combustion Turbine	168	1.8 %	9,178	17.8 %	177	9,187	18.7 %
	Diesel	27	0.3 %	143	0.3 %	91	207	0.4 %
	Run of River Hydro	946	10.2 %	1,146	2.2 %	0	1,146	2.3 %
	Nuclear	0	0.0 %	11,539	22.4 %	0	11,539	23.5 %
	Pumped Storage Hydro	400	4.3 %	1,470	2.9 %	0	1,470	3.0 %
	Steam	7,039	76.1 %	17,362	33.7 %	1	10,324	21.1 %
	Wind	0	0.0 %	0	0.0 %	574	574	1.2 %
	East Total	9,255	100.0 %	51,476	100.0 %	5,461	49,028	100.0 %
South	Combined Cycle	0	0.0 %	3,369	15.6 %	1,275	4,644	22.5 %
	Combustion Turbine	0	0.0 %	3,226	15.0 %	0	3,226	15.6 %
	Diesel	0	0.0 %	105	0.5 %	29	134	0.6 %
	Run of River Hydro	562	18.0 %	562	2.6 %	431	993	4.8 %
	Nuclear	0	0.0 %	3,432	16.0 %	0	3,432	16.6 %
	Pumped Storage Hydro	0	0.0 %	2,646	12.3 %	0	2,646	12.8 %
	Steam	2,552	82.0 %	8,162	38.0 %	0	5,610	27.1 %
	Wind	0	0.0 %	0	0.0 %	0	0	0.0 %
	South Total	3,114	100.0 %	21,502	100.0 %	1,735	20,685	100.0 %
West	Combined Cycle	0	0.0 %	7,692	7.2 %	1,274	8,966	8.4 %
	Combustion Turbine	0	0.0 %	15,671	14.7 %	193	15,864	14.8 %
	Diesel	10	0.1 %	163	0.2 %	28	181	0.2 %
	Run of River Hydro	348	2.0 %	608	0.6 %	147	755	0.7 %
	Nuclear	0	0.0 %	16,837	15.8 %	0	16,837	15.7 %
	Pumped Storage Hydro	240	1.4 %	990	0.9 %	0	990	0.9 %
	Steam	16,404	96.5 %	64,364	60.6 %	7,407	55,367	51.7 %
	Wind	0	0.0 %	0	0.0 %	8,103	8,103	7.6 %
	West Total	17,002	100.0 %	106,325	100.0 %	17,152	107,063	100.0 %
Grand Total		29,371		179,303		24,348	176,776	

Scarcity

Scarcity exists when supply is less than, or equal to, demand where demand includes a level of operating reserves. In PJM, scarcity pricing has resulted under these conditions as the result of the shape of the PJM aggregate supply curve. Scarcity pricing occurred, for example, in the summer of 1999 in PJM. As demand increased, prices rose to $900 per MWh and above. Offer capping for local market power did not affect scarcity pricing in 1999 as increased demand resulted in aggregate market prices that exceeded offer caps for local constraints. There were units with high offers, required to meet the aggregate demand for energy in PJM, that were not required to resolve local transmission constraints and therefore were not offer capped.

In the summer of 2005, the first hot summer since the integrations of Phases 1 through 5, the dynamic in the PJM Energy Market changed. The change was due in part to the larger footprint. PJM's peak load in the summer of 2005 was 130,000 MW while PJM's peak load in the summer of 1999 was 50,000 MW. What had been PJM's entire Energy Market in 1999 was now just a regional part of the market. Units that might have been dispatched in 1999 to meet aggregate PJM load were dispatched in 2005 to resolve constraints associated with bringing lower cost power from the west to east. Rather than import and ramp limits constraining power flows, PJM redispatched units up in the east and down in the west. The result was that rather than units in the eastern part of PJM being dispatched in merit order to meet aggregate demand in the relatively small eastern part of PJM, the units were dispatched out of merit order to solve local constraints. The result, in turn, was that there was not a market mechanism to ensure that prices increased to reflect the scarcity conditions that existed on two occasions.

This set of events led to the conclusion that PJM needed to implement an administrative scarcity pricing mechanism to ensure the appropriate tradeoff between limiting local market power and market prices that reflect scarcity conditions.[42]

In PJM's Energy Market, reliability on very high-load days has been the result of a combination of market-based responses to higher prices by both demand and supply and of administrative emergency actions. There is some demand-side response to high prices as loads voluntarily curtail when they have an incentive to do so and there is some supply-side response to high prices as generators produce more and imports increase. When market-based responses are not adequate, PJM has employed emergency procedures to effectively force supply and demand to match to prevent loss of load.

PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions. These emergency procedures include: emergency energy request events; maximum emergency generation events; manual load dump events; and voltage reduction events.

42 114 FERC ¶61,076 (2006).

Based on the implementation of one or more of these emergency actions over an area consisting of two or more contiguous zones with 5 percent or greater positive distribution factor ("dfax") relative to concurrently binding 500 kV or greater transmission constraints, conditions on two separate days in the summer of 2005 met the definition of scarcity.

There are four emergency messages that reflect scarcity as they have been implemented by PJM.[43] (See Table 3-24.)

In 2005 there were two high-load days with a number of hours that had one or more of the four emergency messages that reflected conditions in two or more contiguous zones with 5 percent or greater positive distribution factor relative to one or more concurrently binding 500 kV or greater transmission constraints.[44] The two days with potential scarcity pricing event hours in 2005 were July 26 and July 27. Of the four types of potential scarcity related emergency action triggers, two types occurred on these days: voltage reduction and maximum emergency generation loaded.

Table 3-24 -Scarcity-related emergency messages

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

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

44 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005) defined criteria for additional scarcity pricing: "Additional Scarcity Pricing Regions must meet the following criteria: (l) consist of at least two entire transmission zones; (2) consist of contiguous transmission zones and sub-zones; (3) transmission import or transfer must be limited by EHV (500 kV or greater) constraints; and (4) consist of pricing nodes that have a 5 percent or greater positive dfax relative to the constraints." The expression transmission zone is synonymous with control zone as used in this report. The Settlement Agreement was approved by the FERC. 114 FERC ¶ 61,076 (January 27, 2006).

July 26 was the first of the two high-load days in 2005 with conditions that were consistent with this definition of scarcity. Figure 3-7 shows PJM's zonal LMPs by hour for July 26, 2005. BGE had the highest zonal hourly price of the day at $283 in the hour ending 1800. BGE load peaked in the same hour at 6,841 MW.

Figure 3-7 - Zonal hourly LMP: For July 26, 2005

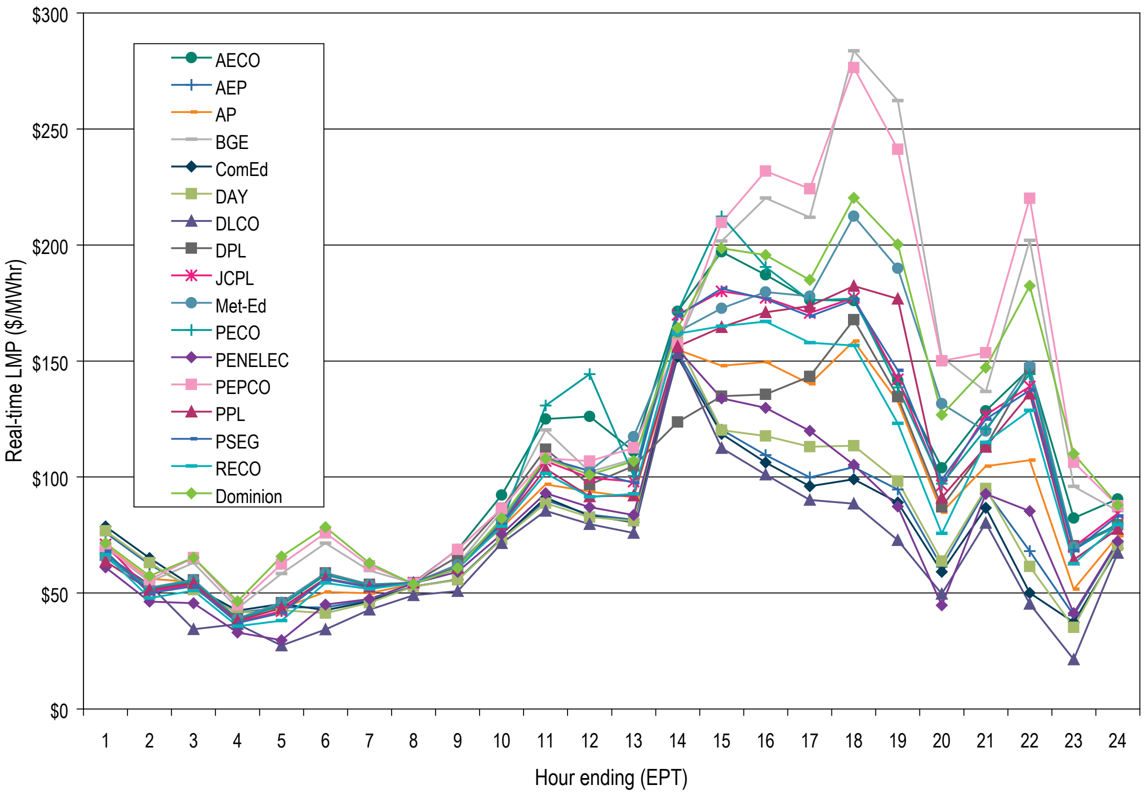
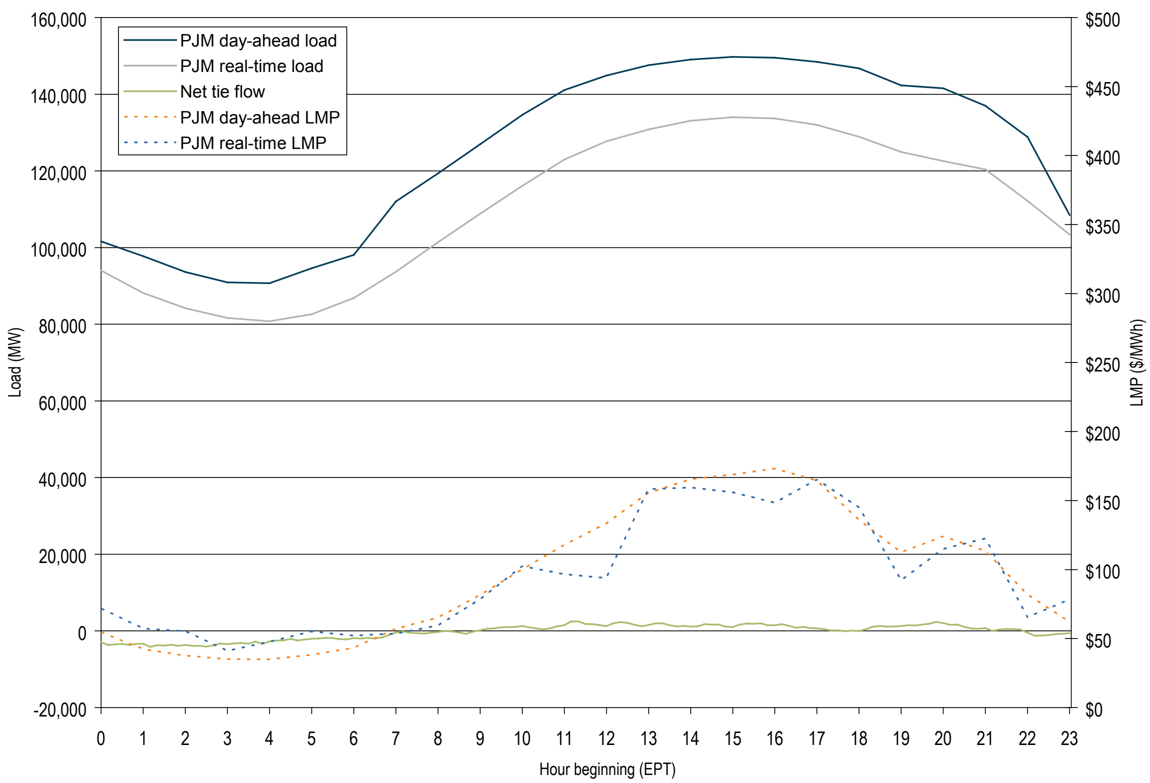


Figure 3-8 shows PJM's hourly load and LMP for both Day-Ahead and Real-Time Markets on July 26. Figure 3-8 also shows the net tie flows by hour on July 26.

Figure 3-8 - PJM load and LMP: For July 26, 2005



Ten 500 kV or greater transmission constraints were active over the day at various hours on July 26. Two contiguous transmission zones[45] in the Mid-Atlantic Region, BGE and PEPCO, had a maximum emergency generation loaded action concurrently in effect for approximately two hours (1636 through 1830).

BGE combined with PEPCO could qualify as a region with scarcity conditions under the definition of scarcity. BGE and PEPCO are two contiguous transmission zones containing generator buses with 5 percent or greater positive distribution factor relative to 500 kV or greater transmission constraints, including Bedington-Black Oak. To the extent that the BGE and PEPCO Control Zones meet this definition and to the extent that the emergency messages related to the BGE and PEPCO zones affected this area, July 26 had two hours in which scarcity existed.

July 27 was the second day in 2005 with conditions consistent with the FERC-approved definition of scarcity.

45 The term transmission zone is generally identical to control zone.

Figure 3-9 shows PJM's zonal LMPs by hour for July 27, 2005. PEPCO had the highest zonal hourly price of the day at $512 in the hour ending 1400. PEPCO load peaked in the same hour at 6,666 MW. Figure 3-10 shows PJM's hourly load and LMP for both the Day-Ahead and Real-Time Markets on July 27.

Figure 3-9 - Zonal hourly LMP: For July 27, 2005

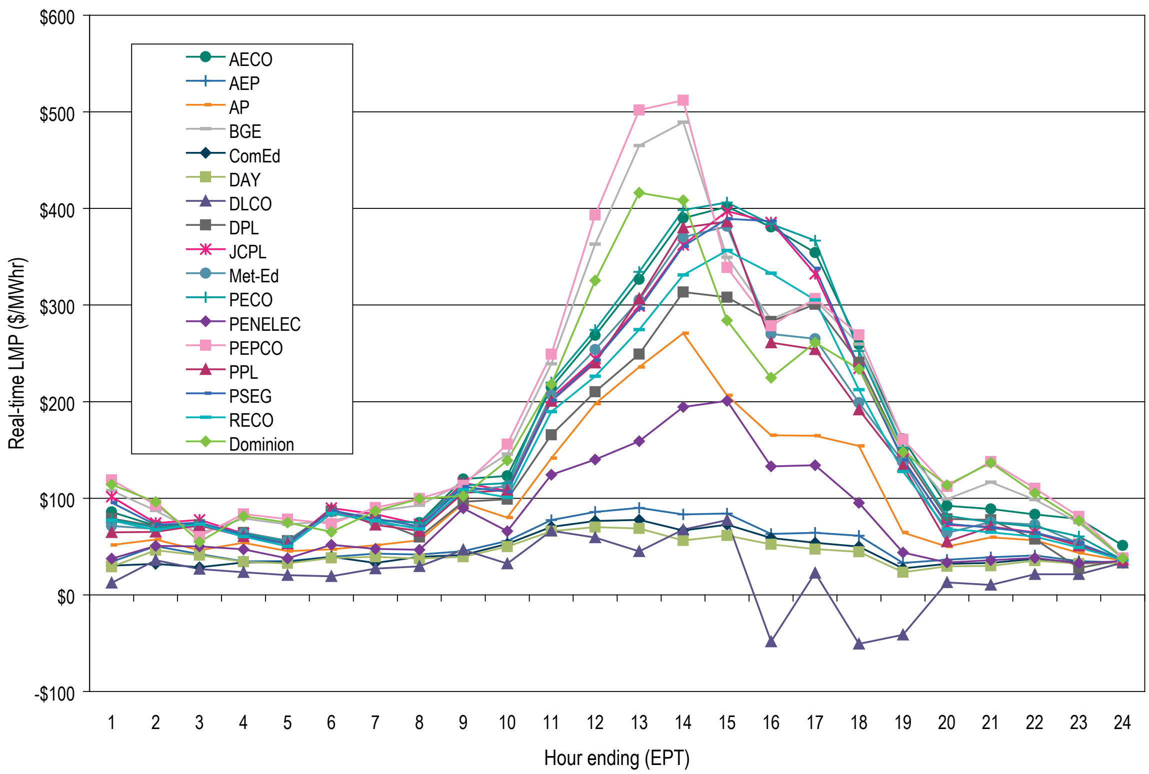
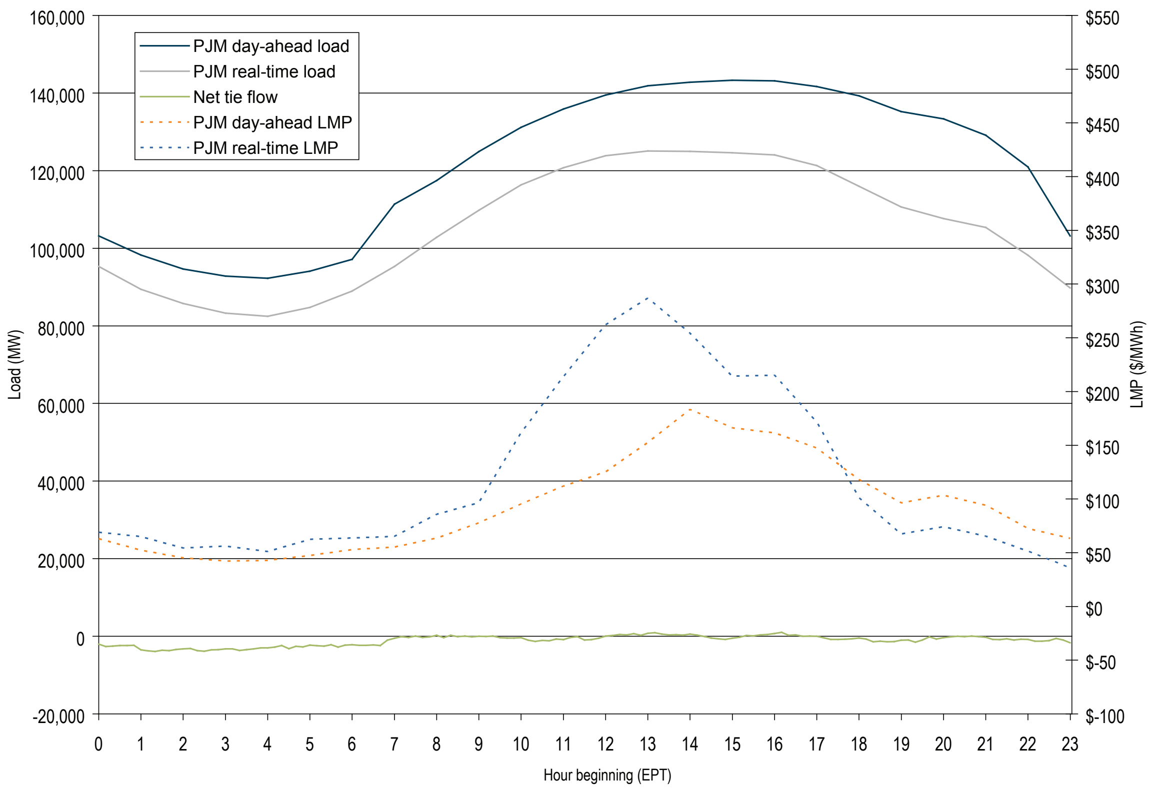


Figure 3-10 also shows the net tie flows by hour on July 27. Eleven 500 kV or greater transmission constraints were active over the day at various hours on July 27.

Figure 3-10 - PJM load and LMP: For July 27, 2005



Between the hours of 1300 and 2000 PJM had a number of active and overlapping scarcity-related emergency messages in effect on July 27. The BGE, PEPCO, Dominion and Potomac Edison had a voltage reduction event that started at 1339. At 1421 PSEG, PECO, JCPL and the eastern portion of PPL also had a voltage reduction event start. The voltage reduction events continued in BGE, PEPCO, Dominion, Potomac Edison, PSEG, PECO, JCPL and eastern PPL concurrently until 1730. BGE and PEPCO had a maximum emergency generation loaded event start at 1340. At 1400 PSEG, PECO, JCPL and eastern PPL also had a maximum emergency generation loaded event start. The voltage reduction events continued in BGE, PEPCO, PSEG, PECO, JCPL and eastern PPL concurrently until 1755.

Combined, BGE, PEPCO, PSEG, PECO, JCPL and eastern PPL comprise a contiguous subset of the Mid-Atlantic Region and Dominion is contiguous with the Mid-Atlantic Region. This area includes two or more contiguous transmission zones containing generator buses with 5 percent or greater positive distribution factor relative to 500 kV or greater transmission constraints. To the extent that these zones met this definition and to the extent that the emergency messages affected this area, July 27 had from 3.5 to 4.5 hours during which scarcity existed.

Operating Reserves

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

If a unit is selected to operate in the PJM Day-Ahead Energy Market based on its offer and the revenues that result from that operation are insufficient to cover all the components of that offer, including startup and no-load, operating reserve credits ensure that all offer components are covered.[46] In addition, if a generator is scheduled for operation in the Real-Time Energy Market and it operates as directed by PJM dispatchers, it is eligible to receive operating reserve credits when its corresponding revenues are not sufficient to cover its offer.

The level of operating reserve credits paid to specific units depends on their offer level and 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. Such PJM operator decisions also interact with unit offer levels and operating parameters to affect operating reserve payments.

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

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

Credits and Charges

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 3-25 shows the categories of credits and charges and their relationship.

Table 3-25 - Operating reserve credits and charges

Credits	Charges
Day-Ahead: →	
Day-Ahead Energy Market	Day-Ahead Demand
Day-Ahead Congestion	Decrement Bids
Day-Ahead Transactions	Day-Ahead Exports
Synchronous Condensing →	Real-Time Load
	Real-Time Exports
Balancing : →	
Balancing Energy Market	Real-Time Deviations
Balancing Congestion	from Day-Ahead Schedules:
Lost Opportunity Cost	
Real-Time Import Transactions	

Day-Ahead	Net Deviation of Total	Real-Time
Day-Ahead Decrement Bids		Real-Time Load
Day-Ahead Load	Demand	Real-Time Sales
Day-Ahead Sales		Real-Time Exports
Day-Ahead Exports		
Day-Ahead Increment Bids	Supply	Real-Time Purchases
Day-Ahead Purchases		Real-Time Imports
Day-Ahead Imports		
Day-Ahead Scheduled Generation	Generator	Real-Time Generation

Day-Ahead Credits and Charges

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

The operating reserve charges that result from paying day-ahead operating reserve credits for an operating day are allocated to PJM members in proportion to their total cleared day-ahead demand, decrement bids and day-ahead exports for that operating day.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for condensing and energy use costs if PJM dispatches them for purposes other than spinning reserve, post-contingency constraint control or reactive services.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to their real-time load plus real-time export transactions.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing Energy Market credits, balancing congestion credits, lost opportunity cost credits and real-time import transaction credits. Daily balancing operating reserve credits are paid to generation resources that operate at PJM's request. If the total payment from the markets is less than the resource's offer, the difference is credited to the PJM member. Lost opportunity cost credits are paid to generation resources when their output is reduced or suspended by PJM for reliability purposes. Like generation resources, real-time import transactions receive balancing operating reserve credits if the total payments received from the markets are less than the real-time offer. Balancing operating reserve credits are also paid to canceled, pool-scheduled resources, to resources providing quick start reserves and to resources performing annual scheduled black start tests.

The operating reserve charges that result from paying balancing operating reserve credits are allocated to real-time hourly deviations from cleared quantities in the Day-Ahead Market. These deviations fall into three categories and are calculated on an hourly net basis: demand, supply and generator deviations. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Deviations in the demand category equal the absolute value of the difference between the sum of the MW quantity of cleared, day-ahead load plus the day-ahead sale transactions scheduled through eSchedules[47] and the Enhanced Energy Scheduler (EES)[48] plus the cleared decrement bids in the Day-Ahead Market and the sum of the MW quantity of real-time load plus real-time sale transactions scheduled through eSchedules and the EES.

47 PJM's eSchedules is an application used by participants for internal bilateral transactions.
48 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

- **Supply.** Deviations in the supply category equal the absolute value of the difference between the sum of the MW quantity of the day-ahead purchase transactions scheduled through eSchedules and EES plus the cleared increment offers in the Day-Ahead Market and the sum of the MW quantity of real-time purchase transactions scheduled through eSchedules and EES.

- **Generator.** Deviations in the generator category equal the absolute value of the difference between a unit's cleared, day-ahead generation and a unit's hourly, integrated real-time generation. More specifically, a unit has 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 ineligible to set LMP for at least one five-minute interval during an hour.

Operating Reserve Credits and Charges

Table 3-26 shows total Energy Market operating reserve credits from 1999 through 2005, a period during which significant market changes occurred.[49] Energy Markets that clear based on market-based generator offers were initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing Energy Market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing services.

Table 3-26 also shows the ratio of total operating reserve charges to the total value of PJM market billings. This ratio decreased from 4.4 percent in 2004 to 2.7 percent in 2005. Over the last seven years, this ratio ranged from a low of 2.7 percent in 2005 to a high of 7.5 percent in 2001.

Table 3-26 - Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2005

	Day-Ahead Energy Market Credit	Balancing Energy Market Credit	Total Energy Market Credit	Annual Credit Change	Operating Reserves as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	NA	$53,588,547	$53,588,547	NA	3.0%	NA	NA	NA	NA
2000	$60,028,266	$86,737,177	$146,765,443	174%	6.5%	$0.34	NA	$0.53	NA
2001	$80,165,425	$170,960,879	$251,126,304	71%	7.5%	$0.27	(20%)	$1.07	100%
2002	$60,148,379	$128,932,236	$189,080,615	(25%)	4.0%	$0.16	(40%)	$0.79	(26%)
2003	$87,309,127	$186,594,404	$273,903,531	45%	4.0%	$0.23	38%	$1.20	52%
2004	$129,230,218	$249,463,523	$378,693,741	38%	4.4%	$0.23	2%	$1.24	3%
2005	$59,614,645	$540,978,140	$600,592,785	59%	2.7%	$0.08	(67%)	$2.76	123%

49 Table 3-26 in Balancing Energy Market Credit includes only Balancing Energy Market credits and Balancing Congestion credits. Day-Ahead Energy Market Credits include Day-Ahead Energy Market and Day-Ahead Congestion credits, but not Day-Ahead Transactions credits. Reported credits include all billing adjustments made by PJM. The categories are defined in Table 3-25.

Finally, Table 3-26 shows Day-Ahead Energy Market and balancing Energy Market operating reserve total credits and credits per MWh for each full year after the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate decreased $0.15 per MWh or about 67 percent from $0.23 per MWh in 2004 to $0.08 per MWh in 2005. The balancing operating reserve rate increased $1.52 per MWh, or about 123 percent, from $1.24 per MWh in 2004 to $2.76 per MWh in 2005.

Table 3-27 compares monthly operating reserve charges by category for calendar years 2004 and 2005. Charges to day-ahead demand, day-ahead exports and decrement bids fell by 54 percent between 2004 and 2005. Charges to real-time load and export transactions increased by 80 percent between 2004 and 2005. Charges to real-time deviations from day-ahead schedules increased by 119 percent between 2004 and 2005. In 2005, charges paid by real-time deviations from their day-ahead schedules represent 87 percent of all 2005 balancing operating reserve charges.

Table 3-27 - Operating reserve charges: Calendar years 2004 and 2005

	2004			2005		
	Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	Real-Time Load and Real-Time Exports	Real-Time Deviations from Day-Ahead Schedules	Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	Real-Time Load and Real-Time Exports	Real-Time Deviations from Day-Ahead Schedules
Jan	$7,237,378	$1,176,853	$42,111,918	$9,567,053	$4,424,843	$37,895,417
Feb	$5,047,471	$551,907	$12,280,720	$3,358,460	$1,720,120	$18,965,471
Mar	$5,181,393	$298,198	$5,116,105	$3,116,002	$1,289,212	$15,360,115
Apr	$2,874,680	$241,961	$10,690,944	$2,847,685	$1,097,556	$12,110,506
May	$7,680,241	$591,312	$27,159,818	$7,582,892	$242,506	$14,646,225
Jun	$13,049,234	$629,545	$30,532,300	$3,043,378	$2,379,770	$58,066,579
Jul	$14,015,970	$355,084	$24,904,235	$2,672,044	$2,680,880	$99,637,963
Aug	$12,966,963	$956,168	$23,549,491	$2,202,173	$3,609,806	$81,020,542
Sep	$8,600,746	$989,893	$15,643,643	$3,035,763	$2,530,569	$76,143,552
Oct	$18,757,488	$588,543	$11,656,103	$5,339,286	$2,141,759	$96,352,636
Nov	$17,128,598	$2,279,189	$15,554,421	$5,493,441	$979,360	$32,242,377
Dec	$16,690,058	$4,560,653	$46,306,867	$11,356,498	$751,026	$37,809,385
Total	$129,230,220	$13,219,306	$265,506,565	$59,614,675	$23,847,406	$580,250,768
Share of Annual Charges						
	31.68%	3.24%	65.08%	8.98%	3.59%	87.43%

Real-Time Deviations

Real-time deviations from day-ahead schedules are used to allocate balancing operating reserve charges and are the denominator in the balancing operating reserve rate calculation. Table 3-28 shows monthly real-time deviations for demand, supply and generator categories for 2004 and 2005. Demand deviation is the largest category while generator deviation is the smallest. From 2004 to 2005, the share of total deviations increased in the demand category by 3.11 percentage points, fell in the supply category by 7.03 percentage points and increased in the generator category by 3.92 percentage points.

Total deviations in 2005 exceeded total 2004 levels from January through April and were less than 2004 levels from October through December.

Table 3-28 - Monthly balancing operating reserve deviations: Calendar years 2004 and 2005

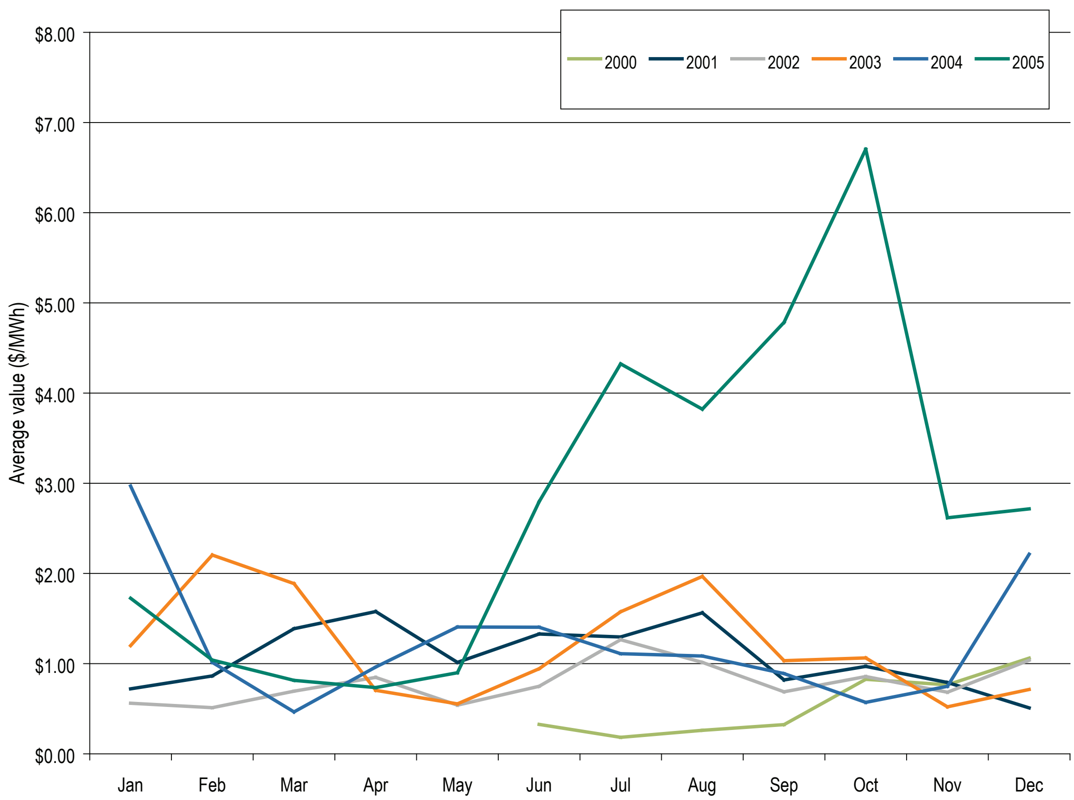
	2004 Deviations			2005 Deviations		
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)
Jan	6,574,494	4,539,070	2,390,883	11,851,254	6,717,597	3,144,258
Feb	5,583,195	4,266,677	1,843,279	9,505,119	5,366,922	3,241,208
Mar	5,755,515	3,467,472	1,889,581	10,367,348	5,198,926	3,637,017
Apr	5,605,423	3,230,722	2,116,433	8,522,724	4,867,238	3,120,261
May	10,311,309	6,070,625	2,473,952	9,280,079	3,893,888	3,395,250
Jun	11,778,882	6,806,620	2,544,211	11,394,615	4,863,249	4,121,267
Jul	12,189,090	7,413,096	2,449,265	13,110,625	5,485,019	4,191,367
Aug	11,474,810	7,314,993	2,411,749	12,021,176	4,702,635	3,783,214
Sep	9,059,839	5,579,295	2,220,747	9,155,776	3,770,614	3,187,321
Oct	10,362,779	6,386,254	3,357,123	7,745,326	3,216,032	2,776,153
Nov	10,583,716	6,262,230	3,904,595	6,971,279	2,822,426	2,343,019
Dec	10,790,676	6,560,068	3,326,017	7,951,859	2,897,055	2,627,646
Total	110,069,728	67,897,122	30,927,835	117,877,180	53,801,601	39,567,981
Share of Annual Deviations						
	52.69%	32.50%	14.81%	55.80%	25.47%	18.73%

Balancing Operating Reserve Rate

The balancing operating reserve rate equals the total amount of balancing operating reserve credits divided by total deviations. It is calculated daily. Figure 3-11 shows monthly average balancing operating reserve rates for the past six years. A large increase in the monthly average balancing operating reserve rate occurred between June and November 2005. The monthly average rate was at its maximum in October 2005 when it reached of $6.70 per MW. The growth in the monthly average rate resulted from an increase in total balancing operating reserve and a decrease in total generator deviations.

The reasons for the observed increase in the operating reserve rate include increased fuel costs, unexpected transmission outages, unanticipated fluctuations in interchange transactions levels and market power.

Figure 3-11 - Monthly average balancing operating reserve rate: June 1, 2000, through December 31, 2005



PJM Installed Capacity and Operating Reserve Credits

Table 3-29 shows the proportion of balancing operating reserve credits received by unit type, the proportion of MW in each unit type receiving balancing operating reserves and the proportion of total PJM capacity by unit type that receives balancing operating reserve payments. CT units received about 53 percent of balancing operating reserve credits although they represented only about 27 percent of the capacity receiving such credits and only 17 percent of total, PJM installed capacity. Steam units received about 21 percent of balancing operating reserve credits, but represented 49 percent of capacity receiving such credits and about 32 percent of total, PJM installed capacity.

Table 3-29 - Installed capacity percentage (By unit type): Calendar year 2005

	Share of Balancing Operating Reserve Credits	Share of Capacity Received Operating Reserve Credits	Share of Total PJM Capacity
CC	25.76%	19.06%	12.23%
CT	52.99%	26.70%	17.14%
Diesel	0.49%	0.24%	0.16%
Nuclear	0.21%	4.79%	3.08%
Steam	20.55%	49.20%	31.57%
Total	100.00%	100.00%	64.18%

Economic and Non-Economic Generation

Non-economic generation includes units that are producing energy but at a higher offer price than the LMP. Economic generation, conversely, includes units producing energy at an offer price less than, or equal, to LMP. The level of non-economic generation is an indicator of the level of generation run for operating reserves. The data are hourly and do not reflect the fact that operating reserve credits are calculated daily. As a result, some generation that is non-economic for an hour may receive adequate market revenues during other hours to offset any shortfall.[50]

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

Figure 3-12 shows PJM hourly average economic and non-economic generation for 2005. It shows that on hourly average PJM has approximately 5,000 MW of non-economic generation and 40,000 MW of economic generation.

Figure 3-12 - PJM hourly average economic and non-economic generation: Calendar year 2005

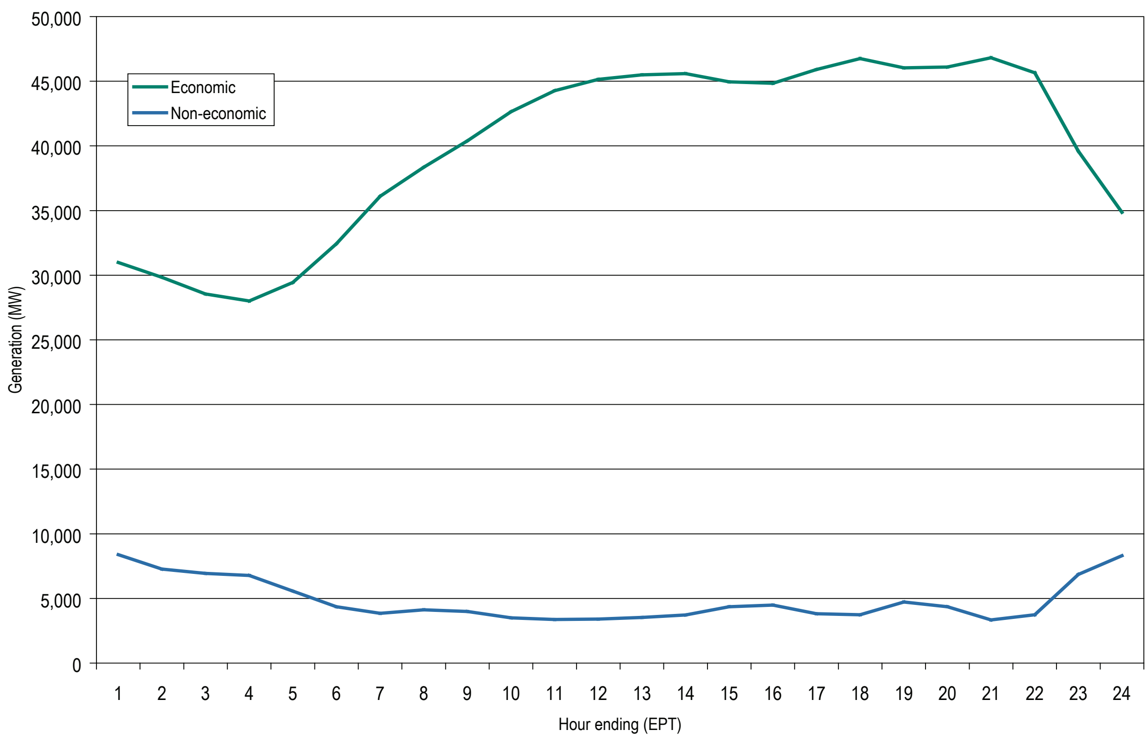


Table 3-30 presents the percentage of total PJM economic and non-economic generation by unit type. During 2005, steam units represented 87 percent of economic generation and about 75 percent of non-economic generation.

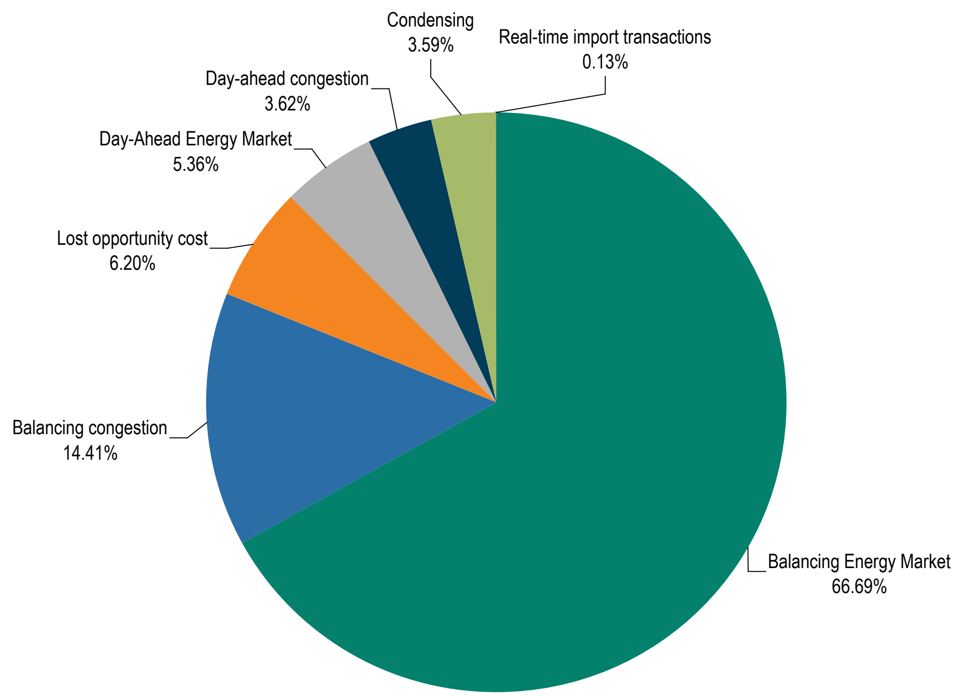
Table 3-30 - PJM economic and non-economic generation: Calendar year 2005

	Economic Generation	Non-Economic Generation
CC	3.50%	14.47%
CT	0.54%	8.35%
Diesel	0.01%	0.09%
Hydro	0.15%	0.00%
Steam	87.28%	74.50%
Nuclear	8.52%	2.59%
Total	100.00%	100.00%

Operating Reserve Credits by Category

Figure 3-13 shows that, at 67 percent, the largest share of total operating reserve credits was paid to resources in the balancing Energy Market during 2005. The next largest share, 14 percent, went to units providing balancing congestion relief. Credits to units for lost opportunity cost were 6 percent of all credits while credits to resources in the Day-Ahead Energy Market were 5 percent, for providing congestion relief in the Day-Ahead Market were 4 percent of all credits and for providing synchronous condensing were 4 percent. The smallest credit share went to real-time import transactions.

Figure 3-13 - Operating reserve credits: Calendar year 2005



Geography of Balancing Operating Reserve Charges and Credits

Table 3-31 compares the share of balancing operating reserve charges paid by and credits[51] paid to generators located within the Mid-Atlantic Region to the share of charges paid by and credits paid to generators located within all other PJM control zones. The other control zones include those in the Western Region (the AEP, AP, ComEd, DAY and DLCO Control Zones) and in the Southern Region (the Dominion Control Zone). On average, 45 percent of all generator charges are paid by generators in the Mid-Atlantic Region and 71 percent of all generator credits are paid to generators in the Mid-Atlantic Region. Table 3-31 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator credits are 83 percent of all operating reserve credits while generator charges are 15 percent of all operating reserve charges.

Table 3-31 - Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2005

	Mid-Atlantic Region		Other Control Zones		Generation Charges Share of Total Operating Reserves Charges	Generation Credits Share of Total Operating Reserves Credits
	Generation Charge	Generation Credit	Generation Charge	Generation Credit		
Jan	50%	89%	50%	11%	11%	73%
Feb	48%	87%	52%	13%	15%	79%
Mar	47%	74%	53%	26%	14%	78%
Apr	43%	63%	57%	37%	14%	71%
May	45%	62%	55%	38%	13%	65%
Jun	45%	73%	55%	27%	18%	91%
Jul	42%	80%	58%	20%	17%	95%
Aug	43%	73%	57%	27%	17%	93%
Sep	45%	59%	55%	41%	18%	93%
Oct	44%	73%	56%	27%	18%	93%
Nov	44%	64%	56%	36%	16%	83%
Dec	49%	61%	51%	39%	15%	76%
Average	45%	71%	55%	29%	15%	83%

51 Balancing operating reserve charges in Table 3-31 include only those in the Generator category. Balancing operating reserve credits in Table 3-31 include Balancing Energy Market credits, Balancing Congestion credits and Lost Opportunity Cost credits. Categories are defined in Table 3-25.

Fuel Cost Increases and Operating Reserve Credits

Increases in fuel costs from 2004 to 2005 increased the cost of generation and thus increased operating reserve credits to generating units. Approximately $268 million of the $580 million in total balancing operating reserve credits resulted from increased fuel costs.

The monthly difference between total actual and fuel-cost-adjusted balancing operating reserve credits are shown in Figure 3-14.

Figure 3-14 - Fuel-cost-adjusted balancing operating reserve credits (All unit types): Calendar year 2005

The monthly difference between actual and fuel-cost-adjusted balancing operating reserve charges on a per MWh basis are shown in Table 3-32.

Table 3-32 - Fuel-cost-adjusted balancing operating reserve rate: Calendar year 2005

	Current Balancing Rate	Fuel-Cost-Adjusted Rate
Jan	1.72	1.53
Feb	1.04	0.84
Mar	0.81	0.45
Apr	0.73	0.47
May	0.90	0.81
Jun	2.80	1.93
Jul	4.32	3.11
Aug	3.82	1.95
Sep	4.78	1.29
Oct	6.70	2.27
Nov	2.62	1.45
Dec	2.72	0.88
Annual Average	2.75	1.42

Market Power Issues

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

The actions of PJM operators are also part of any analysis of market power affecting the level of operating reserve credits. It is the decisions of PJM operators, constrained by their available tools, by the requirement to maintain system reliability and by the available generating resources, that effectively put units in a position to exercise market power with respect to the payment of operating reserve credits. A complete resolution of the market power issue must provide PJM operators better tools for defining and making optimal economic choices and must determine when the constraints on those choices effectively create market power opportunities when units are called on out of merit order and do not set price.

Top 10 Units

Balancing operating reserve credits have been paid to a disproportionately small number of units and companies since 2001. As Table 3-33 shows, in 2004 the top 10 units received 46.3 percent of total operating reserve payments and 27.7 percent of total operating reserve credits in 2005. In 2005, less than 1 percent of the units received 27.7 percent of total operating reserve credits. This decrease in the share of the top 10 units is largely a result of the fact that the number of units nearly doubled from the beginning of 2004 through the end of 2005. In 2004 the top 10 units were owned by three companies and in 2005 the top 10 were owned by four companies. In 2004 the top generator received 20 percent of the total operating reserves paid and in 2005 the top generator received 15 percent of the total operating reserves.

Table 3-33 - Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2005

	Percent
2001	46.7%
2002	32.0%
2003	39.3%
2004	46.3%
2005	27.7%

Markup

Unit Markups - Top 10 Units

To determine the contribution that unit price offers, in excess of cost, make to operating reserve payments, the MMU performed a markup analysis of the top 10 units.[52] As Table 3-34 shows, the markup for the top 10 units averaged 75.4 percent in 2005, a substantial increase over prior years. The markup for the top 10 units is a weighted average, where the weights are generator output when operating reserves are paid. The increased markup in 2005 resulted from a higher unit-specific markups combined with increased hours during which PJM dispatched units with high markups out of merit order.

The generation owner with the largest share of top 10 credits received 53 percent of operating reserve credits paid to the top 10 units and had a weighted-average markup of 55.4 percent in 2005. The next generation owner received 22 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 235.0 percent and the third generation owner received 20 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 0.0 percent in 2005.

52 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as outlined in PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005).

For each year 2001 to 2005, the top 10 units receiving operating reserve credits were either conventional steam or CC technology generation, as shown in Table 3-34.

Half of the top 10 units are exempt from offer capping. Of all 9,540 hours when the top 10 units operated in real time and received balancing operating reserve credits in the Energy Market, only about 0.5 percent were offer-capped.

Table 3-34 - Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2005

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	Combined Cycle Percent of Top 10	Combined Cycle Markup
2001	2.9%	60%	2.2%	40%	7.4%
2002	11.3%	54%	8.0%	46%	20.4%
2003	16.9%	50%	19.4%	50%	11.3%
2004	3.0%	12%	0.1%	88%	4.9%
2005	75.4%	20%	52.9%	80%	81.7%

Unit Markups - All Units

Table 3-35 shows the simple average markup for generators exempt[53] from offer capping, for generators not exempt from offer capping and for all generators, when balancing operating reserves were paid.[54] The simple average markup for exempt CC and CT units is about 25 percentage points higher than for non-exempt units. The simple average markup for exempt diesel units is about 5 percentage points lower than for non-exempt diesel units. The associated maximum markups exceeded the average levels by a substantial amount; the maximum markup for an exempt unit was in excess of 650 percent.

Table 3-35 - Simple average generator markup: Calendar year 2005

Unit Class	Exempt	Non-Exempt	All Units
All Units	23.7%	8.2%	10.5%
CC	22.2%	(1.8%)	10.3%
CT	27.3%	2.5%	6.0%
Diesel	(4.1%)	0.8%	0.1%
Steam	NA	23.8%	23.8%

53 Generator exempt status is determined per 112 FERC ¶ 61,031 (2005). See also PJM Interconnection, L.L.C., Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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

Impact of Markups by Exempt Units

Table 3-36 compares total balancing operating reserve rate[55] and the balancing operating reserve rate adjusted to remove all markups above 10 percent for exempt units. This comparison shows the impact on operating reserve charges of markups over cost by units exempt from offer-capping rules. The impact is the result of increased markups by the 45 exempt units that received balancing operating reserve credits in 2005. The most significant difference between actual total credits and adjusted credits occurred during the July through October period when the balancing operating reserve rate was the highest of the year. The cumulative current total balancing operating reserve credit would have been lower by about $94 million in 2005 if exempt units were subject to offer capping and if the units would have been subject to offer-capping rules at the times they were paid operating reserve credits. If exempt units that received balancing operating reserves for generation were subject to offer capping and if the units would have been subject to offer-capping rules at the times they were paid operating reserve credits, then the balancing operating reserve rate would have been, on average, 15 percent lower than it was in 2005.[56]

Table 3-36 - Balancing operating reserve rate for exempt units (Actual and markup-adjusted): Calendar year 2005

	Current Rate	Markup-Adjusted Rate
Jan	1.72	1.33
Feb	1.04	0.88
Mar	0.81	0.65
Apr	0.73	0.67
May	0.90	0.79
Jun	2.80	2.69
Jul	4.32	3.15
Aug	3.82	3.11
Sep	4.78	4.31
Oct	6.70	5.52
Nov	2.62	2.30
Dec	2.72	2.53
Annual Average	2.75	2.33

55 Total balancing operating reserve credits do not take into account manual adjustments made after the billing period by PJM market settlement procedures.
56 The fuel-cost impact and the markup impact are not additive, but show separately the sensitivity of operating reserve charges to each factor.

Unit Operating Parameters

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

While a complete analysis of the impact of restrictive operating parameters on operating reserve credits has not been completed, preliminary analysis indicates that the submission of such parameters does increase operating reserve credits paid to some units.

SECTION 4 – INTERCHANGE TRANSACTIONS

The integration of two additional service territories into the PJM regional transmission organization (RTO) in 2005 significantly expanded PJM's geographic footprint and brought modest changes to its external interfaces. These interfaces are the seams between PJM and other regions. PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials.

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[1]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

- **Phase 2 (2004).** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[4]

- **Phase 3 (2004).** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone.

1 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

2 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

Overview

Interchange Transaction Activity

Aggregate Imports and Exports

- **Phase 4.** During the four months ended April 30, 2005, PJM, including the DLCO Control Zone, was a net exporter of power, with monthly net interchange averaging -1.2 million MWh.[5] Gross monthly import volumes averaged 3.7 million MWh while gross monthly exports averaged 4.9 million MWh.

- **Phase 5.** During the remaining eight months ended December 31, 2005, PJM, including the Dominion Control Zone, continued to be a net exporter of power. Monthly average net interchange was -1.5 million MWh. Gross monthly import volumes averaged 2.7 million MWh while gross monthly exports averaged 4.2 million MWh.

Interface Imports and Exports[6]

- **Phase 4.** During Phase 4, the two largest net exporting interfaces totaled 36 percent of the total net exporting volume: Michigan Electric Coordinated System (PJM/MECS) at 19 percent and PJM/New York Independent System Operator interface (PJM/NYIS) with 17 percent. Ninety-three percent of the net import volume was carried on three interfaces: PJM/Ohio Valley Electric Corporation (PJM/OVEC) carried 39 percent, PJM/Illinois Power (PJM/IP) carried 38 percent and PJM/Duke Energy Corp. (PJM/DUK) carried 16 percent of the volume.

- **Phase 5.** During Phase 5, the two largest net exporting interfaces totaled 51 percent of the total net exporting volume: Tennessee Valley Authority (PJM/TVA) with 29 percent and MidAmerican Electric Company (PJM/MEC) at 22 percent. Ninety-two percent of the net import volume was carried on three interfaces: PJM/OVEC carried 57 percent, PJM/IP carried 22 percent and FirstEnergy Corp. (PJM/FE) carried 13 percent of the volume.

Modified Interfaces and Pricing Points

- **Removal of Interfaces.** Integration of the DLCO Control Zone into PJM on January 1, 2005, resulted in the removal of the PJM/DLCO interface. The subsequent integration of the Dominion Control Zone on May 1, 2005, resulted in the removal of the PJM/VAP interface.

- **Pricing Point Changes.** On January 1, 2005, the DLCO pricing point was eliminated as a result of the DLCO integration. On April 1, 2005, the MISO pricing point was created as a result of the Midwest ISO's introduction of markets. On May 1, 2005, the Southeast pricing point was modified to account for the integration of the Dominion Control Zone.

5 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

6 Interfaces are named after adjacent control areas. As is true of the control areas themselves, this naming convention does not imply anything about any company operating within the control areas.

Interchange Transaction Topics

Existing and Proposed Operating Agreements with Bordering Areas

- **Midwest ISO.** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[7] entered its second phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[8] The Joint Reliability Coordination Agreement (JRCA), executed on April 22, 2005, provides for the active management of seams among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The Agreement provides for comprehensive reliability management and congestion relief among the three regions.

- **PJM and Progress Energy Carolinas, Inc. (PEC) Joint Operating Agreement (JOA).**[9] An operating agreement between PJM and PEC, approved by the FERC on September 9, 2005, with an effective date of July 30, 2005, provides for market-to-non market coordination.

PJM TLRs

- The number of transmission loading relief procedures (TLRs) issued by PJM declined after the integration of the AEP and DAY Control Zones. The integration meant that PJM could redispatch generating units to relieve constraints on facilities in the newly integrated areas where PJM had previously relied on TLRs for constraint control. The result was a drop in the number of TLRs called by PJM, particularly in the AEP Control Zone.

Actual Versus Scheduled Power Flows

- Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Loop flows have negative consequences because they constitute unscheduled use of PJM's transmission system, affect real-time system operations and affect the revenue adequacy of Financial Transmission Rights (FTR) because loop flows do not pay congestion costs. Although PJM's total scheduled and actual flows differed by about 4 percent in 2005, there were significant differences for individual interfaces. PJM's method of defining pricing points is designed to provide price signals consistent with the actual power flows and thus to minimize the incentive to create loop flow.

7 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA) (December 31, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (2.73 MB).

8 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) <http://www.pjm.com/documents/downloads/agreements/20050422-jrca-final.pdf> (145 KB).

9 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) < http://www.pjm.com/documents/ferc/documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

Interchange Issues

- **PJM and Midwest ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/MISO interface and at the MISO/PJM interface appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

- **PJM and New York ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/NYIS interface and at the New York Independent System Operator (NYISO) PJM proxy bus appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the NYISO. As in 2004, however, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- **Consolidated Edison and PSEG Wheeling Contracts.** Two contracts governing wheeling of up to 1,000 MW of power through PJM into New York City were the subject of a November 2001 complaint to the FERC. The FERC issued an order on May 18, 2005, defining a protocol to resolve this issue which was implemented in July 2005. Based on early performance of the protocol, Consolidated Edison has formally asked the FERC to require PJM and NYISO to improve operations under the protocol to increase delivery performance, and PJM and NYISO are working to resolve these issues.

- **Ramp and Transmission Reservations.** PJM should consider development of rules that limit a market participant's ability to reserve more ramp than is actually either needed or used in order to facilitate the efficient use of limited ramp capability.

Conclusion

The PJM Market Monitoring Unit (MMU) analyzed the transactions between PJM and neighboring control areas for 2005 including evolving transactions patterns, economics and issues. The location of PJM transactions with external areas has changed significantly as a result of the substantial expansion of the PJM footprint over the last two years. New interfaces dominate export and import activity. In contrast to the first five years of PJM operations, PJM continued the recent pattern of being a net exporter of energy. While exports and imports have historically primarily cleared in the Real-Time Energy Market, transactions in the Day-Ahead Energy Market continued to grow in volume. PJM has entered into a number of agreements with neighboring control areas that govern reliability and economic coordination. As interactions with external areas are increasingly governed by economic redispatch, interface prices and volumes reflect supply and demand conditions and the number of TLRs has declined. PJM continues to face significant loop flows with substantial impacts on PJM for reasons that are not yet well understood. A cooperative analysis with the Midwest ISO would contribute to the understanding that is required before a solution can be designed. The Consolidated Edison/PSEG wheeling contracts are now managed under a FERC-approved protocol that has improved operations and additional improvements are being made. The allocation and management of ramp, the capability to import into or export from PJM, continue to create potential issues and improvements are also required in this area.

Interchange Transaction Activity

Aggregate Imports and Exports (by Phase)

With the integration of the ComEd Control Area and reinforced by the integration of the AEP and DAY Control Zones in Phases 2 and 3, PJM became a systematic net exporter of power for the first time since the introduction of markets. PJM continued to be a net exporter of power in both Phases 4 and 5. (See Figure 4-1 and Figure 4-3.)

Phase 4

During Phase 4, PJM was a net exporter of energy for each month. Total net interchange of -5.0 million MWh during January through April 2005 compares to a net interchange of 7.4 million MWh for the comparable period in 2004. (Note the sign change from the previous year's comparable period.) For these four-month periods, the peak months for net interchange were January in 2005 (-1.8 million MWh) and January in 2004 (2.3 million MWh).

Phase 5

During Phase 5, PJM continued to be a net exporter of energy in each month. Monthly exports averaged 4.2 million MWh and monthly imports averaged 2.7 million MWh for an average monthly net interchange of -1.5 million MWh.

2005 Trends

While PJM market participants have historically imported and exported energy primarily in the Real-Time Energy Market (See Figure 4-1.), that pattern began to change in 2004 and the volume of transactions in the Day-Ahead Energy Market continued to grow in 2005. Although day-ahead volume continues to be smaller by comparison, the difference is decreasing. (See Figure 4-2.) In 2005, import transactions in the Day-Ahead Energy Market were 50 percent of the import volume (27 percent in 2004) in the Real-Time Market while export transactions in the Day-Ahead Market were 50 percent of the gross export volume (39 percent in 2004) in the Real-Time Market.

Import transactions in the Day-Ahead Market were highest at the PJM/OVEC and PJM/FE interfaces during both phases of 2005. In Phase 4, PJM/OVEC accounted for 45 percent and PJM/FE accounted for 27 percent of the average hourly volume. In Phase 5, they were 49 percent and 21 percent, respectively. Export transactions in the Day-Ahead Market were highest at the PJM/MEC and PJM/NYIS interfaces in both phases of 2005. In Phase 4, PJM/MEC accounted for 15 percent and PJM/NYIS accounted for 12 percent of the average hourly volume. In Phase 5, they were 18 percent and 20 percent, respectively. Transactions in the Day-Ahead Market create a financial obligation to deliver in the Real-Time Market and if the obligation is not fulfilled in the Real-Time Market, operating reserve charges will also be incurred.

Figure 4-1 - PJM real-time imports and exports: Calendar year 2005

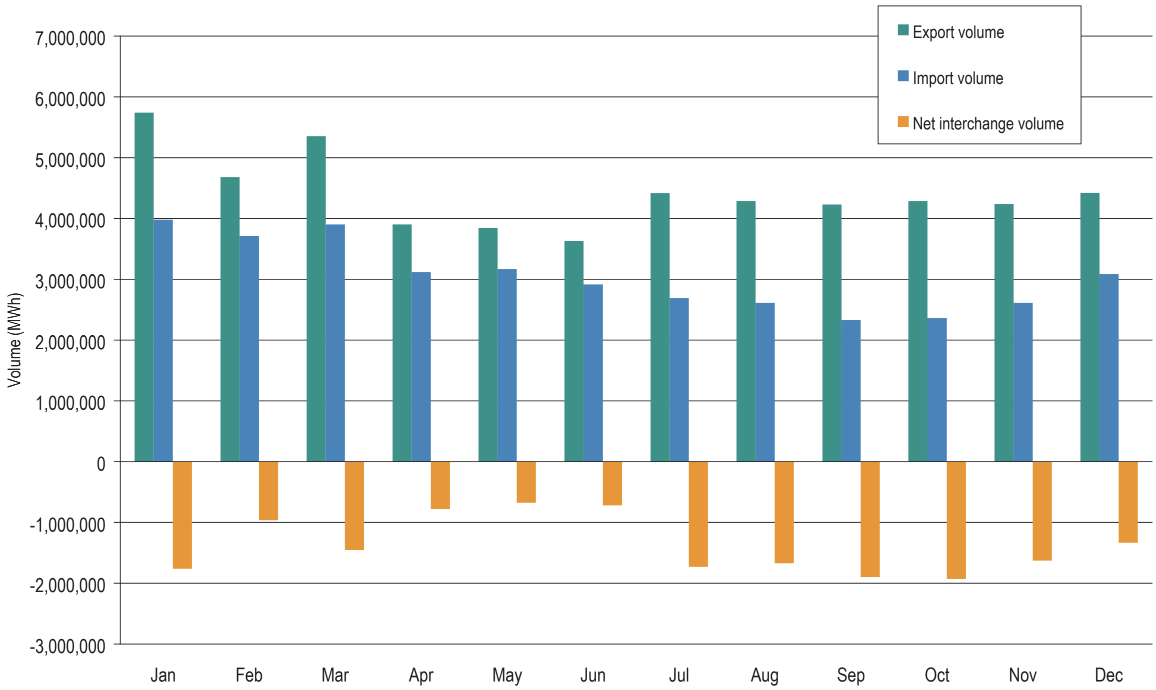


Figure 4-2 - Total day-ahead import and export volume: Calendar year 2005

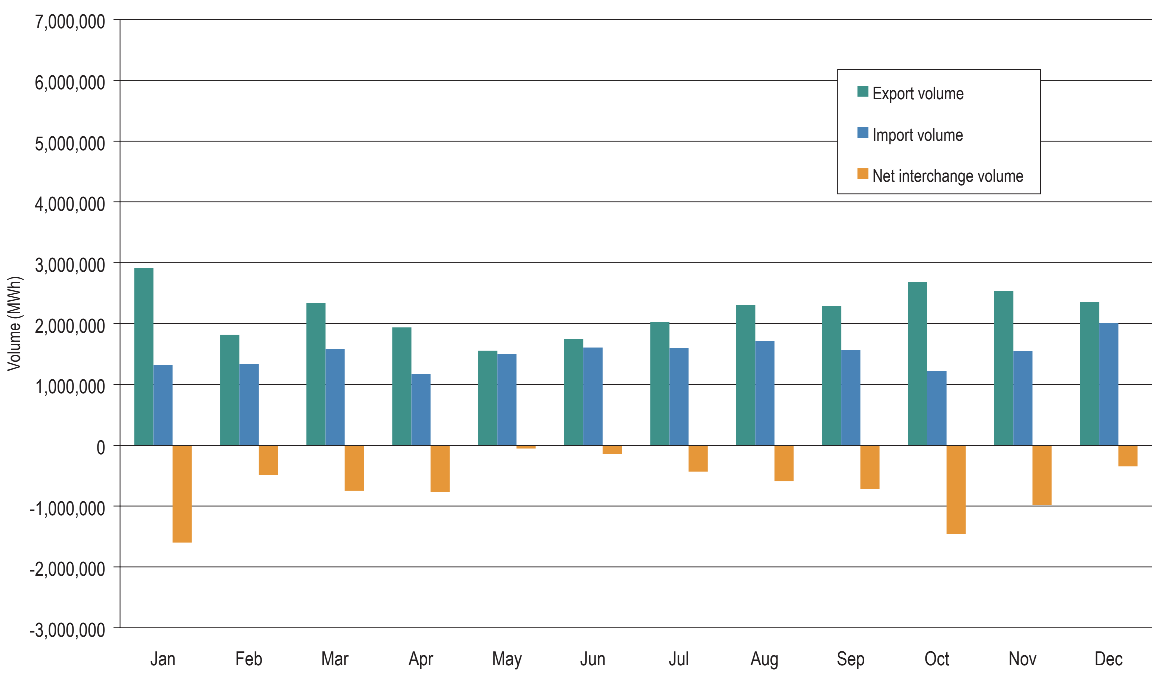
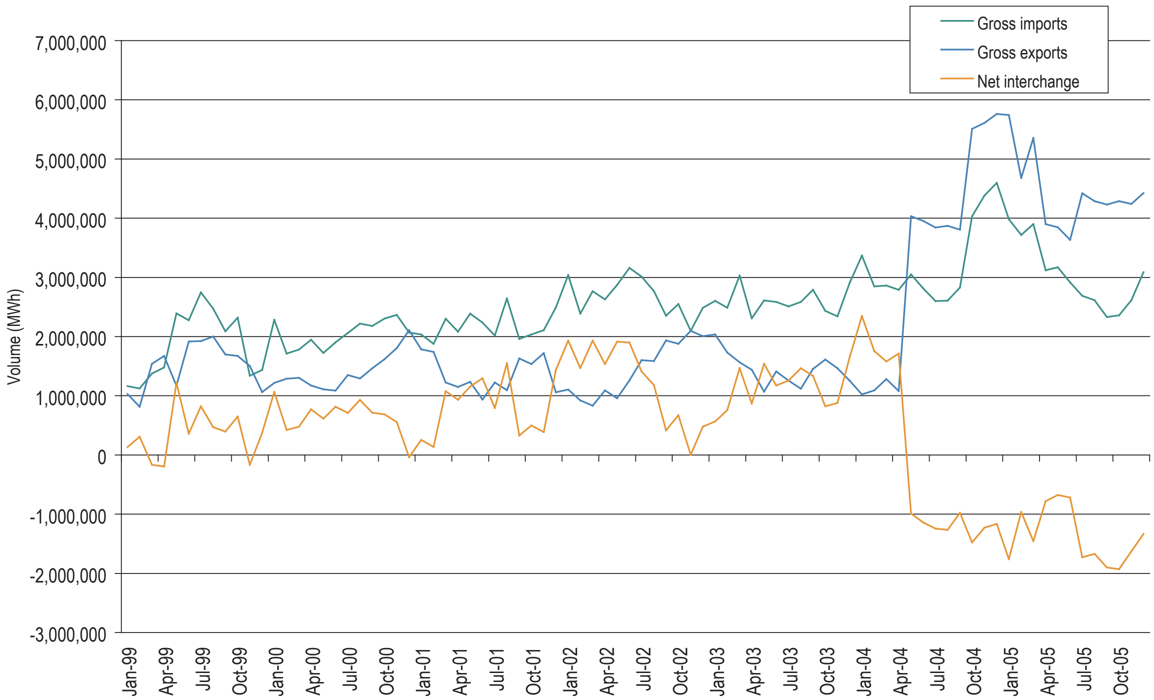


Figure 4-3 shows import and export volume for PJM from 1999 through 2005. Gross exports exhibited a particularly sharp increase in Phase 2 that was not matched by imports while the increase in gross exports and imports in Phase 3 was more balanced. During Phases 4 and 5, gross imports and exports generally declined while net interchange fluctuated with no clear trend.

Figure 4-3 - PJM import and export transaction volume history: Calendar years 1999 to 2005



Interface Imports and Exports (by Phase)

Total imports and exports are comprised of flows at each PJM interface. Net interchange is shown by interface for each phase of 2005 in Table 4-1 while gross imports and exports are shown by interface for each phase of 2005 in Table 4-2 and Table 4-3.

Phase 4

There were net exports at 15 of PJM's 22 interfaces in Phase 4. Two exporting interfaces accounted for 36 percent of the total net exports, PJM/MECS at 19 percent and PJM/NYIS at 17 percent. Gross exports at four interfaces made up half of gross exports, PJM/NYIS at 16 percent, PJM/MECS at 13 percent, PJM/Cinergy Corporation (CIN) at 11 percent and PJM/MEC at 10 percent.

There were net imports at the remaining seven of PJM's interfaces in Phase 4. Three interfaces accounted for 93 percent of the net import volume, PJM/OVEC with 39 percent, PJM/IP with 38 percent and PJM/DUK with 16 percent of the volume. Gross imports at three interfaces accounted for more than half (54 percent) of gross imports, PJM/IP at 21 percent, PJM/OVEC at 20 percent and PJM/CIN at 13 percent.

Phase 5

There were net exports at 16 of PJM's 21 interfaces in Phase 5. Two exporting interfaces accounted for 51 percent of the total net exports, PJM/TVA with 29 percent and PJM/MEC at 22 percent. PJM/NYIS, which had been PJM's largest net exporting interface prior to the integrations, was the third largest in Phase 5 with 16 percent of the net exporting volume. Gross exports at three interfaces made up 58 percent of gross exports, PJM/NYIS at 21 percent, PJM/TVA at 21 percent and PJM/MEC at 16 percent.

There were net imports at the remaining five of PJM's interfaces in Phase 4. Three interfaces accounted for 92 percent of the net import volume, PJM/OVEC with 57 percent, PJM/IP with 22 percent and PJM/FE with 13 percent of the volume. Gross imports at three interfaces accounted for 60 percent of gross imports, PJM/OVEC at 32 percent, PJM/FE at 14 percent and PJM/NYIS at 14 percent.

Table 4-1 - Net interchange volume by interface (MWh x 1,000): Calendar year 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FE	(343.1)	71.5	5.7	178.2	344.8	122.6	138.2	179.0	174.7	210.5	221.7	205.8	1,509.6
NYIS	(628.4)	(441.5)	(569.2)	(502.1)	(715.4)	(441.4)	(443.2)	(348.0)	(452.3)	(625.9)	(389.7)	(342.9)	(5,900.0)
VAP	(237.5)	(160.4)	(188.2)	(282.7)	NA	NA	NA	NA	NA	NA	NA	NA	(868.8)
ALTE	(112.5)	(145.3)	(169.8)	(106.6)	(114.2)	(141.8)	(166.6)	(109.7)	(105.8)	(109.2)	(106.2)	(109.1)	(1,496.8)
ALTW	(132.2)	(112.8)	(242.3)	(223.2)	(140.8)	(175.5)	(154.7)	(118.0)	(116.6)	(117.4)	(138.3)	(130.8)	(1,802.6)
AMRN	(24.6)	64.0	(3.4)	(173.3)	(91.9)	(185.2)	(179.5)	(168.8)	(171.6)	(188.9)	(161.0)	(126.5)	(1,410.7)
CILC	1.9	7.1	7.4	0.0	0.5	0.9	(1.2)	0.0	0.7	(4.9)	(33.0)	(18.1)	(38.7)
IP	1,019.0	727.5	706.6	394.5	366.8	317.4	319.4	316.1	310.8	328.7	328.8	333.6	5,469.2
MEC	(539.5)	(445.6)	(306.2)	(517.6)	(642.9)	(456.4)	(571.8)	(632.4)	(700.4)	(768.0)	(559.3)	(774.1)	(6,914.2)
NIPS	22.0	41.2	132.7	(4.3)	(0.1)	(0.8)	(0.2)	(0.3)	(15.5)	(0.3)	(1.1)	(0.1)	173.2
WEC	(415.6)	(404.1)	(556.1)	(93.8)	(84.5)	(103.6)	(126.9)	(129.9)	(124.7)	(129.2)	(112.5)	(99.0)	(2,379.9)
MECS	(952.1)	(652.8)	(677.1)	(118.7)	(54.3)	(118.2)	(138.5)	(126.2)	(155.0)	(92.3)	(89.1)	(92.1)	(3,266.4)
CPLE	(161.7)	(165.0)	(123.3)	(174.2)	(91.4)	(150.9)	(216.6)	(209.7)	(203.1)	(71.2)	127.9	148.8	(1,290.4)
CPLW	(72.2)	(67.1)	(72.2)	(71.3)	(50.5)	(71.1)	(73.3)	(67.8)	(70.1)	(74.7)	(20.7)	(73.7)	(784.7)
CIN	(195.0)	(103.7)	(142.5)	219.3	332.7	8.1	(286.9)	(359.6)	(316.0)	(329.6)	(176.6)	(36.3)	(1,386.1)
DUK	250.8	229.3	374.2	335.4	5.5	290.7	207.4	146.9	(117.0)	10.4	(56.1)	143.2	1,820.7
EKPC	(7.3)	(3.3)	(15.3)	(28.6)	(27.6)	14.2	(6.1)	(16.9)	(7.9)	(37.5)	(72.3)	(121.9)	(330.5)
IPL	(14.2)	1.8	4.7	(0.3)	(0.3)	0.2	0.0	0.0	(0.2)	(0.2)	(0.7)	(1.3)	(10.5)
LGEE	71.4	67.1	84.0	36.3	46.3	44.9	48.6	33.9	50.5	(1.1)	33.7	(0.1)	515.5
OVEC	748.8	703.6	743.3	707.6	923.9	859.4	827.1	843.8	831.5	818.8	842.8	849.1	9,699.7
TVA	(38.6)	(176.3)	(447.9)	(356.2)	(681.7)	(531.2)	(904.9)	(904.4)	(711.4)	(730.0)	(1,266.0)	(1,089.2)	(7,837.8)
CWLP	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	(18.7)	0.0	0.0	(18.0)
Total	(1,760.6)	(964.5)	(1,454.5)	(781.6)	(675.1)	(717.7)	(1,729.7)	(1,672.0)	(1,899.4)	(1,930.7)	(1,627.7)	(1,334.7)	(16,548.2)

Table 4-2 - Gross import volume by interface (MWh x 1,000): Calendar year 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FE	334.0	459.1	388.5	422.6	542.5	346.6	337.3	335.9	288.1	342.7	396.1	400.0	4,593.4
NYIS	203.7	231.1	282.2	283.2	219.1	396.6	396.4	477.1	428.2	336.4	371.5	465.8	4,091.3
VAP	28.3	24.6	33.4	16.5	NA	NA	NA	NA	NA	NA	NA	NA	102.8
ALTE	0.1	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.7	1.6	5.0
ALTW	5.5	6.1	9.9	1.4	1.9	1.0	0.0	0.1	0.3	0.2	0.0	0.9	27.3
AMRN	201.8	238.6	138.5	124.3	133.6	59.6	63.1	34.3	40.3	40.8	36.2	56.5	1,167.6
CILC	6.7	8.9	9.6	0.2	0.5	1.0	0.2	0.0	0.7	0.0	1.3	6.4	35.5
IP	1,093.2	783.8	744.9	443.0	389.2	357.3	354.2	338.0	323.9	328.9	328.8	333.8	5,819.0
MEC	42.7	37.5	19.7	15.9	9.1	13.3	10.0	7.0	8.5	12.6	34.6	35.5	246.4
NIPS	44.0	75.4	142.6	0.0	0.8	0.2	0.0	0.0	0.1	0.0	0.0	0.0	263.1
WEC	2.0	0.2	1.5	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.0	0.0	4.0
MECS	30.8	40.9	93.1	20.4	57.3	24.9	39.4	17.7	4.9	24.7	23.9	22.9	400.9
CPLE	136.2	125.9	178.3	84.5	42.0	56.7	59.5	66.4	39.3	115.8	227.3	397.7	1,529.6
CPLW	0.0	0.0	4.2	0.0	0.0	0.0	0.4	0.7	0.0	0.0	0.0	0.0	5.3
CIN	472.5	483.9	486.1	454.4	511.9	298.4	132.0	131.6	108.9	103.4	123.0	203.2	3,509.3
DUK	435.4	389.6	495.0	471.5	249.2	398.0	387.9	290.1	179.0	209.3	186.9	280.3	3,972.2
EKPC	9.1	13.9	15.7	16.4	30.2	33.8	6.9	1.4	6.3	0.7	1.3	0.0	135.7
IPL	7.5	6.6	8.6	0.2	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	23.2
LGEE	74.1	73.2	89.5	42.4	49.6	47.6	49.4	49.1	51.2	0.1	34.9	0.0	561.1
OVEC	759.0	711.4	749.1	715.7	932.8	880.3	849.7	865.6	849.6	839.2	843.2	861.5	9,857.1
TVA	94.7	4.5	8.9	7.0	0.4	0.5	4.5	0.7	0.3	3.6	1.6	22.5	149.2
CWLP	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Total	3,981.3	3,715.5	3,900.2	3,119.6	3,170.1	2,916.2	2,690.9	2,615.7	2,329.6	2,358.7	2,613.3	3,088.6	36,499.7

Table 4-3 - Gross export volume by interface (MWh x 1,000): Calendar year 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FE	677.1	387.6	382.8	244.4	197.7	224.0	199.1	156.9	113.4	132.2	174.4	194.2	3,083.8
NYIS	832.1	672.6	851.4	785.3	934.5	838.0	839.6	825.1	880.5	962.3	761.2	808.7	9,991.3
VAP	265.8	185.0	221.6	299.2	NA	NA	NA	NA	NA	NA	NA	NA	971.6
ALTE	112.6	145.3	170.3	106.6	114.2	141.8	166.6	109.7	105.8	109.3	108.9	110.7	1,501.8
ALTW	137.7	118.9	252.2	224.6	142.7	176.5	154.7	118.1	116.9	117.6	138.3	131.7	1,829.9
AMRN	226.4	174.6	141.9	297.6	225.5	244.8	242.6	203.1	211.9	229.7	197.2	183.0	2,578.3
CILC	4.8	1.8	2.2	0.2	0.0	0.1	1.4	0.0	0.0	4.9	34.3	24.5	74.2
IP	74.2	56.3	38.3	48.5	22.4	39.9	34.8	21.9	13.1	0.2	0.0	0.2	349.8
MEC	582.2	483.1	325.9	533.5	652.0	469.7	581.8	639.4	708.9	780.6	593.9	809.6	7,160.6
NIPS	22.0	34.2	9.9	4.3	0.9	1.0	0.2	0.3	15.6	0.3	1.1	0.1	89.9
WEC	417.6	404.3	557.6	93.8	84.5	103.7	126.9	129.9	124.7	129.4	112.5	99.0	2,383.9
MECS	982.9	693.7	770.2	139.1	111.6	143.1	177.9	143.9	159.9	117.0	113.0	115.0	3,667.3
CPLE	297.9	290.9	301.6	258.7	133.4	207.6	276.1	276.1	242.4	187.0	99.4	248.9	2,820.0
CPLW	72.2	67.1	76.4	71.3	50.5	71.1	73.7	68.5	70.1	74.7	20.7	73.7	790.0
CIN	667.5	587.6	628.6	235.1	179.2	290.3	418.9	491.2	424.9	433.0	299.6	239.5	4,895.4
DUK	184.6	160.3	120.8	136.1	243.7	107.3	180.5	143.2	296.0	198.9	243.0	137.1	2,151.5
EKPC	16.4	17.2	31.0	45.0	57.8	19.6	13.0	18.3	14.2	38.2	73.6	121.9	466.2
IPL	21.7	4.8	3.9	0.5	0.3	0.1	0.0	0.0	0.2	0.2	0.7	1.3	33.7
LGEE	2.7	6.1	5.5	6.1	3.3	2.7	0.8	15.2	0.7	1.2	1.2	0.1	45.6
OVEC	10.2	7.8	5.8	8.1	8.9	20.9	22.6	21.8	18.1	20.4	0.4	12.4	157.4
TVA	133.3	180.8	456.8	363.2	682.1	531.7	909.4	905.1	711.7	733.6	1,267.6	1,111.7	7,987.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.7	0.0	0.0	18.7
Total	5,741.9	4,680.0	5,354.7	3,901.2	3,845.2	3,633.9	4,420.6	4,287.7	4,229.0	4,289.4	4,241.0	4,423.3	53,047.9

2005 Trends

With the integrations of the DLCO and Dominion Control Zones, PJM continued to be a net exporter of power through both integrations. The shift from a net importer to a net exporter of power began with the integration of ComEd in Phase 2 of 2004 and continued through Phases 4 and 5 of 2005. The gross import and export volumes decreased in Phases 4 and 5.

Modified Interfaces and Pricing Points

During 2005, because of the Phase 4 and Phase 5 integrations, PJM retired the DLCO pricing point, the PJM/DLCO interface and the PJM/VAP interface and redefined the Southeast pricing point. When the Midwest ISO market became operational, PJM added the MISO pricing point.

Removal of Interfaces

PJM experienced two integrations in 2005, each of which changed the number of external interfaces. (See Table 4-4.) When the DLCO Control Zone became part of PJM in Phase 4, the external interfaces changed and the PJM/DLCO interface was retired.

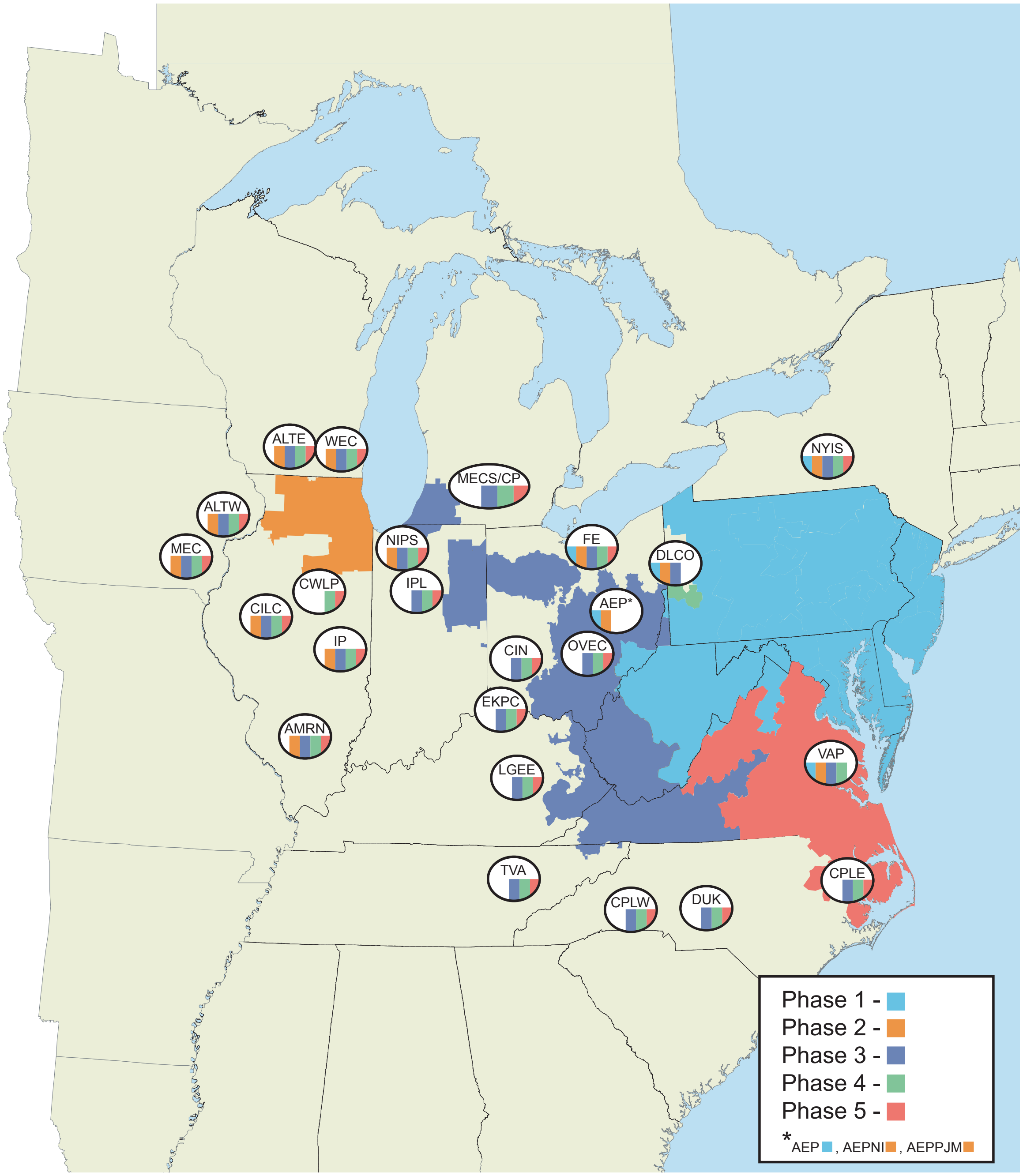
When the Dominion Control Zone became part of PJM in Phase 5, the boundaries shifted again. The number of external interfaces was reduced to 21 and the PJM/VAP interface was retired.

Table 4-4 - Active interfaces: Calendar year 2005

	Phase 4				Phase 5							
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DLCO												
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
VAP	Active	Active	Active	Active								
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMRN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CILC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

The approximate geographic location of these interfaces can be seen in Figure 4-4.

Figure 4-4 - PJM's evolving footprint and its interfaces



Changes to Interface Pricing Points

Interface pricing points differ from interfaces. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[10] PJM establishes prices for transactions with external control areas by assigning interface pricing points to individual areas. Interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically for areas that are both adjacent to and not adjacent to PJM. Transactions between PJM and external control areas need to be priced at the PJM border. A set of external buses is used to create such interface prices.[11] The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and external sources of energy and, therefore, to create price signals that embody underlying economic fundamentals.[12]

Before the DLCO and Dominion Control Zone integrations, the nine PJM interface pricing points had been: NYISO, MICHFE, DLCO, Northern Indiana Public Service Company (NIPSCO), Northwest, Southwest, Southeast, OVEC and the Ontario Independent Electricity System Operator (Ontario IESO).

Interface pricing points were retired, added and modified in 2005. In Phase 4 the DLCO pricing point was retired, reflecting the integration of the Duquesne Light Company control area. No new pricing point was required since all surrounding areas were already accounted for in existing pricing point definitions. On April 1, 2005, the Midwest ISO pricing point was added in response to startup of the Midwest ISO market. In Phase 5, the Southeast pricing point was modified to account for the integration of the Dominion Control Zone. Table 4-5 presents the interface pricing points used during 2005.

Table 4-5 - Active pricing points by interface: Calendar year 2005

	Phase 4				Phase 5							
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DLCO												
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MICHFE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO				Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

10 See Appendix D, "Interchange Transactions," for a more detailed discussion of interface pricing.

11 See "LMP Aggregate Definitions" < http://www.pjm.com/markets/energy-market/downloads/20060103-aggregate-definitions.xls> (1.33 MB).

12 See Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Interchange Transaction Topics

During 2005, four broad topics emerged involving interchange transactions. PJM developed and implemented operating agreements with bordering areas, PJM TLRs were partially displaced by economic dispatch, PJM faced significant loop flow issues and PJM addressed a range of issues emerging from existing interfaces, contracts and technical issues.

Existing and Proposed Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues PJM and its neighbors have developed and continue to work on joint operating agreements. These agreements are in various stages of development and include an implemented operating agreement with Midwest ISO, an executed operating agreement with Progress Energy Carolinas, Inc. and a reliability agreement with TVA.

The PJM/ Midwest ISO Joint Operating Agreement (JOA)

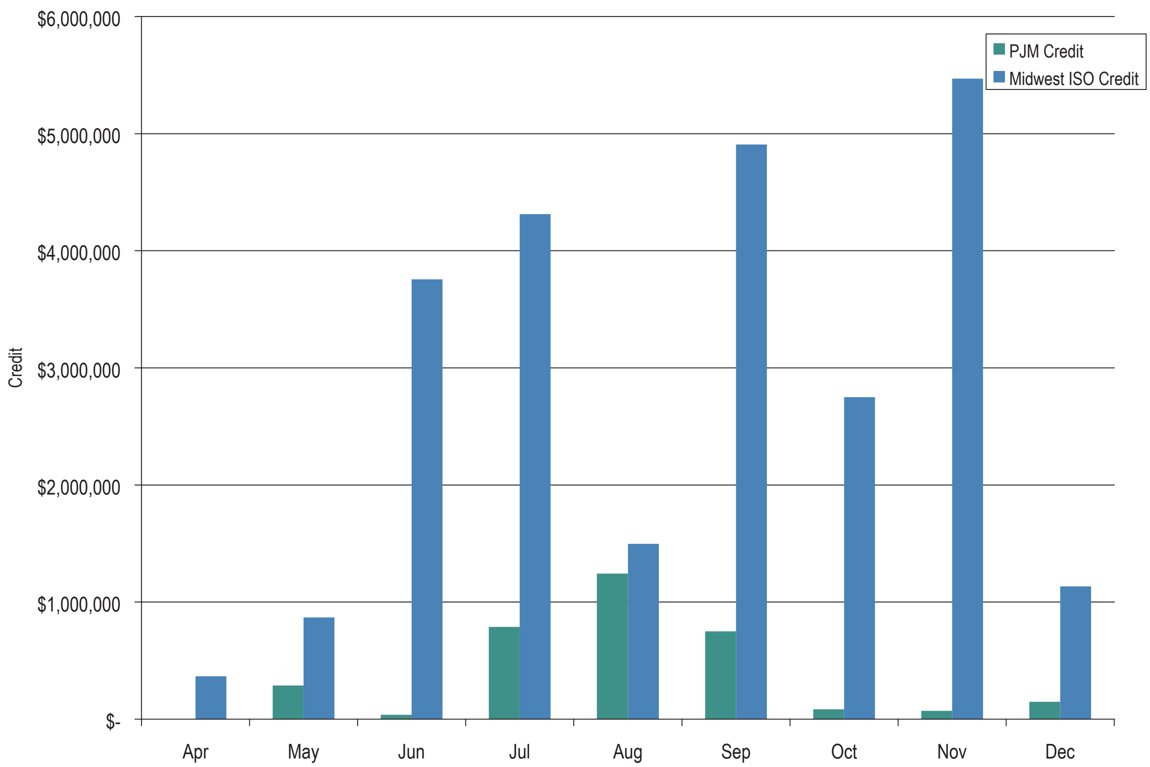
On April 1, 2005, the Midwest ISO market became operational. This triggered the second, market-to-market phase, of the JOA.

The JOA includes features designed to improve reliability, including provisions governing the sharing of operating information, system models, planning data, outage coordination and emergency planning. The second phase added jointly coordinated, least cost redispatch for congestion control between the two markets.

Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate locational marginal prices (LMPs) for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its computation of the MISO/PJM pricing point.

Since April, the market-to-market operations have resulted both in Midwest ISO and PJM redispatching units to control congestion in the other's area and in the exchange of payments for this redispatch. Figure 4-5 presents the monthly credits each organization has received from redispatching for the other. The largest payments from PJM to Midwest ISO in the April through December period were the result of redispatch by Midwest ISO to relieve congestion on the Eau Clair – Arpin 345 kV line that was the result of PJM dispatch to meet load. Total PJM payments to Midwest ISO were $7.6 million. The largest payments from Midwest ISO to PJM in the April through December period were the result of redispatch by PJM to relieve congestion on the Mt. Storm-Pruntytown 500 kV line that was the result of Midwest ISO dispatch to meet load. Total Midwest ISO payments to PJM were $1.5 million.

Figure 4-5 - Credits for coordinated congestion management: April through December 2005



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The parties share critical operating information, system models and extensive planning data to ensure that all have the best information possible in their day-to-day operations. Information-sharing enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Similar to the JOA between PJM and the Midwest ISO, the JRCA uses coordinated flowgates to address congestion within and across systems. When redispatch by the market-based entity is able to aid congestion management between market and non market systems, the overall cost of the congestion reduction is lower. However, unlike the PJM-Midwest ISO market-to-market agreement, there are no payments among the parties for market-to-non market coordination.

The three organizations also conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. Planning will be conducted in a manner consistent with Midwest ISO and PJM's respective tariffs and the laws and rules pertaining to TVA's status as a regional, non-FERC jurisdictional entity.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The JOA provides for the management of congestion and key points of the agreement include the parties establishing an operating committee, sharing operating data, using coordinated flowgates to address congestion, coordinating scheduled outages, operating jointly during emergencies, coordinating transmission planning studies, maintaining joint checkout procedures and coordinating voltage and reactive power.

Since Progress Energy Carolinas is not a market system, the coordination between PEC and PJM is similar to that between the Midwest ISO and PJM during the first phase of their JOA. PEC and PJM plan to control flows over coordinated flowgates with a combination of redispatch and TLRs. The details are expected to be completed during the first half of 2006.

PJM TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve the issue. TLRs are generally called to control flows related to external control areas as redispatch within an LMP market can generally resolve overloads on internal transmission facilities. PJM called fewer TLRs in 2005, after the integrations of the DLCO and Dominion Control Zones, than had been called in 2004. Total PJM TLRs declined by 24 percent, from 429 during 2004 to 326 in 2005 (See Figure 4-6.) while, as a result of the expanded footprint, the number of unique flowgates for which PJM declared TLRs increased from 55 different flowgates during 2004 to 69 different flowgates in 2005. (See Figure 4-7 for monthly data.) Of the 326 TLRs called by PJM in 2005, four facilities comprised 57 percent of the total. The four facilities were:

- **Wylie Ridge Transformers.** This is a 500 kV substation, located in West Virginia near the Ohio River at the western edge of the AP Control Zone. West–to-east power flows frequently overload one of these transformers on a contingency basis for the loss of the other transformer. (67 TLRs in 2005);

- **Kammer #200 765 to 500 kV Transformer for Loss of Belmont-Harrison 500 kV Line.** This is a 765 to 500 kV transformer located near the border of Ohio and West Virginia. The Belmont-Harrison 500 kV line runs in northern West Virginia near the southwest corner of Pennsylvania. Economic dispatch of lower cost units in the west can cause high flows at Kammer. This constraint is not easily controllable with redispatch because of lack of generation with the necessary impact (50 TLRs in 2005);

- **Roseland-Cedar Grove F 230 kV Line for Loss of Roseland-Cedar Grove B 230 kV Line.** These parallel path lines are located in northern New Jersey. Power transfers to New York and loop flows are the main reasons for TLRs on this line (39 TLRs in 2005); and

- **Cloverdale-Lexington 500 kV Line for Loss of Pruntytown-Mount Storm 500 kV Line.** The Cloverdale-Lexington line is in southern Virginia and the Pruntytown-Mount Storm line runs between West Virginia and Maryland just south of Pennsylvania. Unit operation at the Bath County pumped storage facility, when in the pumping mode, aggravates this constraint. The problem is not easily controllable with redispatch because of lack of generation with the necessary impact (29 TLRs in 2005).

In 2005, the top three facilities for which PJM called TLRs were the same as in 2004 although their share of all TLRs declined. Wylie Ridge, Cloverdale-Lexington and Roseland-Cedar Grove accounted for 41 percent of PJM's TLRs in 2005 and 61 percent in 2004.

During June, an unusually large number of TLRs were called in the ComEd Control Zone, with 13 TLRs called on seven facilities. In most months, very few TLRs are called in the ComEd Control Zone. A combination of high loads in the ComEd Control Zone, outages on the King - Eau Claire line and on the Cherry Valley TR82 transformer, generator retirements in ComEd and the dispatching of new units in Wisconsin caused June's TLR increase.

Figure 4-6 - PJM and Midwest ISO TLR procedures: Calendar years 2004 and 2005

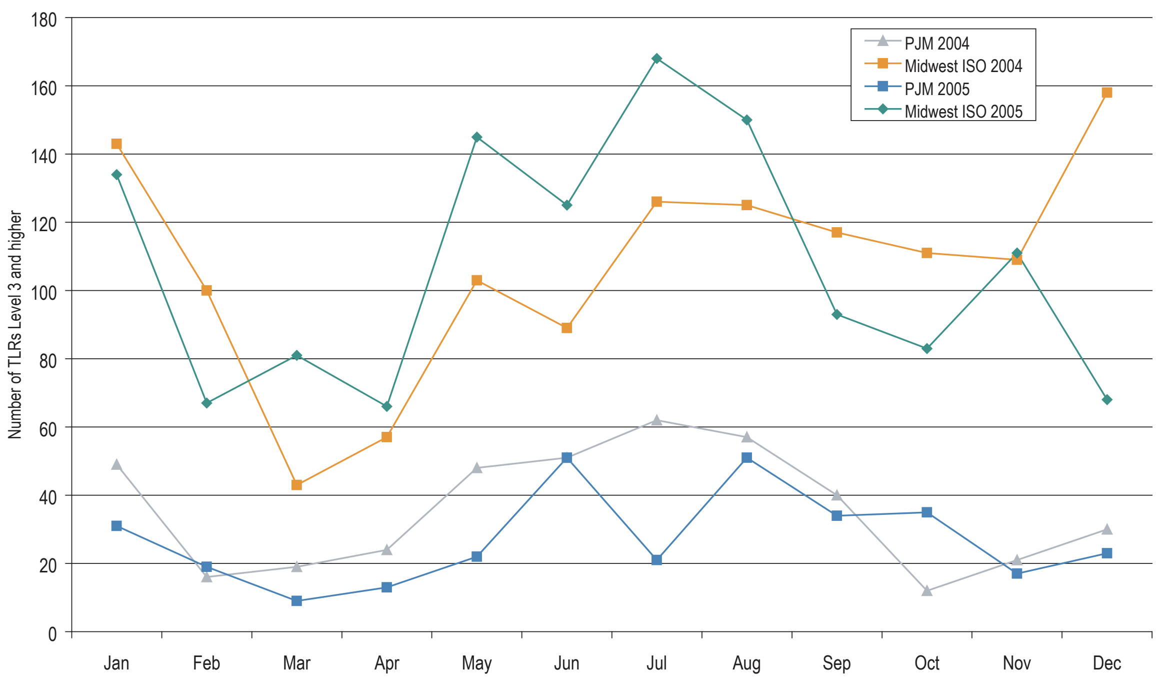
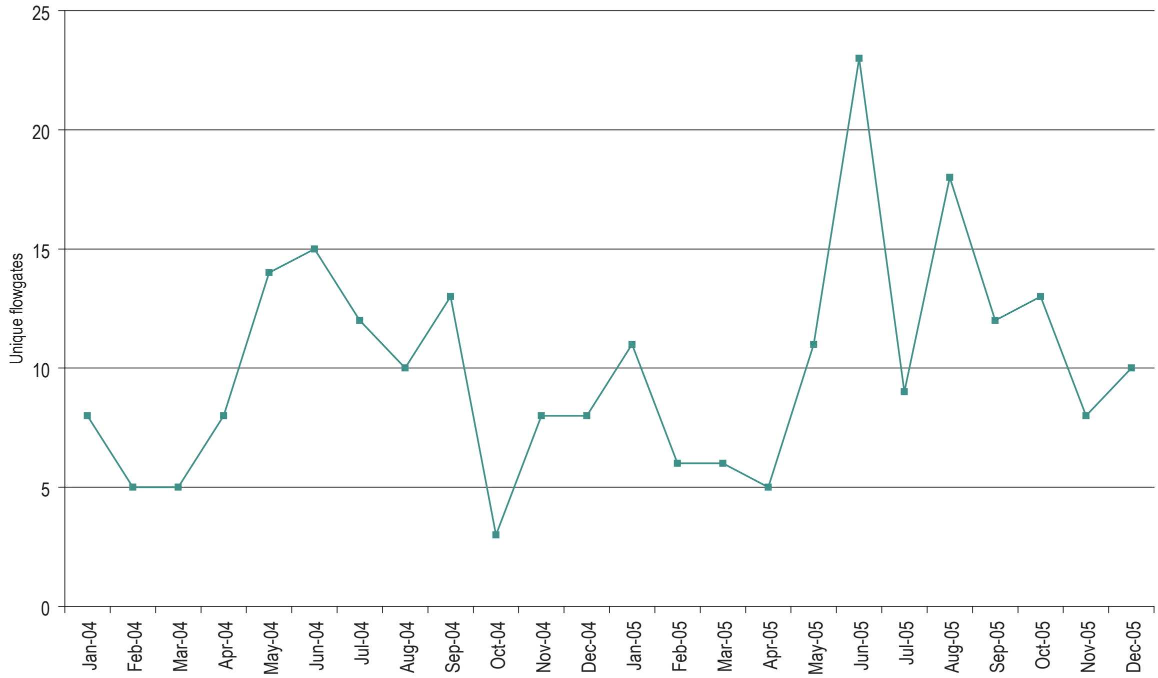


Figure 4-7 - Number of unique PJM flowgates: Calendar years 2004 to 2005



Actual Versus Scheduled Power Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled to flow at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow despite the fact that the actual and scheduled flows could net to a zero difference.

Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path although actual, associated energy deliveries flow on the path of least resistance. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of redispatch and TLR procedures.

The fact that total PJM net actual interface flows were only about 4 percent less than net scheduled interface flows on average for 2005 as a whole is not a useful measure of either net interchange or of loop flow. There were differences between net scheduled and actual interchange for both Phase 4 and Phase 5, although they were in opposite directions in each phase and, more importantly, there were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-6.) PJM tries to balance overall actual and scheduled interchange, but does not attempt to maintain a balance between actual and scheduled interchange at individual interfaces.

During Phase 4, for PJM as a whole, net scheduled and actual interchange differed by approximately 6 percent. Actual system exports were 5.270 million MWh, in excess of the scheduled total exports of 4.961 million MWh by 0.309 million MWh. Flow balance varied at each individual interface. The PJM/TVA interface was the most imbalanced, with net actual imports of 1.486 exceeding scheduled exports of 1.019 by 2.505 million MWh or -246 percent, for an average of 870 MW during each hour of the period. At the PJM/MECS interface, net actual exports exceeded scheduled exports by 2.211 million MWh or 92 percent. At the PJM/IP interface, net scheduled imports exceeded actual imports by 1.903 million MWh or 67 percent. At the PJM/NYIS interface, net actual exports exceeded scheduled exports by 1.550 million MWh or 72 percent. At the PJM/ALTE interface, net actual exports exceeded scheduled exports by 1.481 million MWh or 277 percent.

During Phase 5, for PJM as a whole, net scheduled and actual interchange differed by approximately 9 percent. Actual system exports were 10.523 million MWh, less than the scheduled total of 11.571 million MWh by 1.048 million MWh. Flow balance varied at each individual interface. The PJM/MECS interface was the most imbalanced, with net actual exports exceeding scheduled exports by 7.974 million MWh or 924 percent, for an average of 1,356 MW during each hour. At the PJM/TVA interface, net actual imports of 0.212 exceeded scheduled exports of 6.804 by 7.016 million MWh or 103 percent. At the PJM/CPLE interface actual imports exceeded scheduled exports by 4.550 million MWh or 686 percent. At the PJM/CIN interface actual imports exceeded scheduled exports by 4.087 million MWh or 350 percent.

Table 4-6 - Net scheduled and actual PJM interface flows (MWh x 1,000): Calendar year 2005

	Actual	Net Scheduled	Difference (MW)	Difference
ALTE	(2,015)	(534)	(1,481)	277%
ALTW	(770)	(711)	(59)	8%
AMRN	288	(137)	425	(310%)
CILC	382	17	365	2147%
CIN	772	(222)	994	(448%)
CPLE	595	(624)	1,219	(195%)
CPLW	(453)	(283)	(170)	60%
CWLP	(105)	1	(106)	(10600%)
DUK	252	1,190	(938)	(79%)
EKPC	239	(55)	294	(535%)
FE	(827)	(87)	(740)	851%
IP	945	2,848	(1,903)	(67%)
IPL	1,104	(8)	1,112	(13900%)
LGEE	274	259	15	6%
MEC	(1,206)	(1,810)	604	(33%)
MECS	(4,612)	(2,401)	(2,211)	92%
NIPS	(1,049)	192	(1,241)	(646%)
NYIS	(3,693)	(2,143)	(1,550)	72%
OVEC	3,962	2,905	1,057	36%
TVA	1,486	(1,019)	2,505	(246%)
VAP	(394)	(869)	475	(55%)
WEC	(445)	(1,470)	1,025	(70%)
Phase 4 System	(5,270)	(4,961)	(309)	6%
ALTE	(4,265)	(959)	(3,306)	345%
ALTW	(1,905)	(1,089)	(816)	75%
AMRN	(962)	(1,273)	311	(24%)
CILC	268	(55)	323	(587%)
CIN	2,920	(1,167)	4,087	(350%)
CPLE	3,887	(663)	4,550	(686%)
CPLW	(1,311)	(500)	(811)	162%
CWLP	(425)	(19)	(406)	2137%
DUK	(1,505)	625	(2,130)	(341%)
EKPC	61	(276)	337	(122%)
FE	754	1,584	(830)	(52%)
IP	1,560	2,611	(1,051)	(40%)
IPL	2,159	(2)	2,161	(108050%)
LGEE	441	257	184	72%
MEC	(3,398)	(5,081)	1,683	(33%)
MECS	(8,837)	(863)	(7,974)	924%
NIPS	(710)	(18)	(692)	3844%
NYIS	(7,604)	(3,737)	(3,867)	103%
OVEC	8,046	6,766	1,280	19%
TVA	212	(6,804)	7,016	(103%)
WEC	91	(908)	999	(110%)
Phase 5 System	(10,523)	(11,571)	1,048	(9%)
2005 Total	(15,793)	(16,532)	739	(4%)

The PJM/MECS interface exhibited large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. (See Figure 4-8 and Figure 4-9.) Generally, the PJM/MECS interface is an exporting interface meaning that power flows from PJM to MECS. The actual exports exceed the scheduled exports at that interface by an average of 1,203 MW for those off-peak hours.

Figure 4-8 - PJM/MECS interface average actual minus scheduled volume: Phase 4

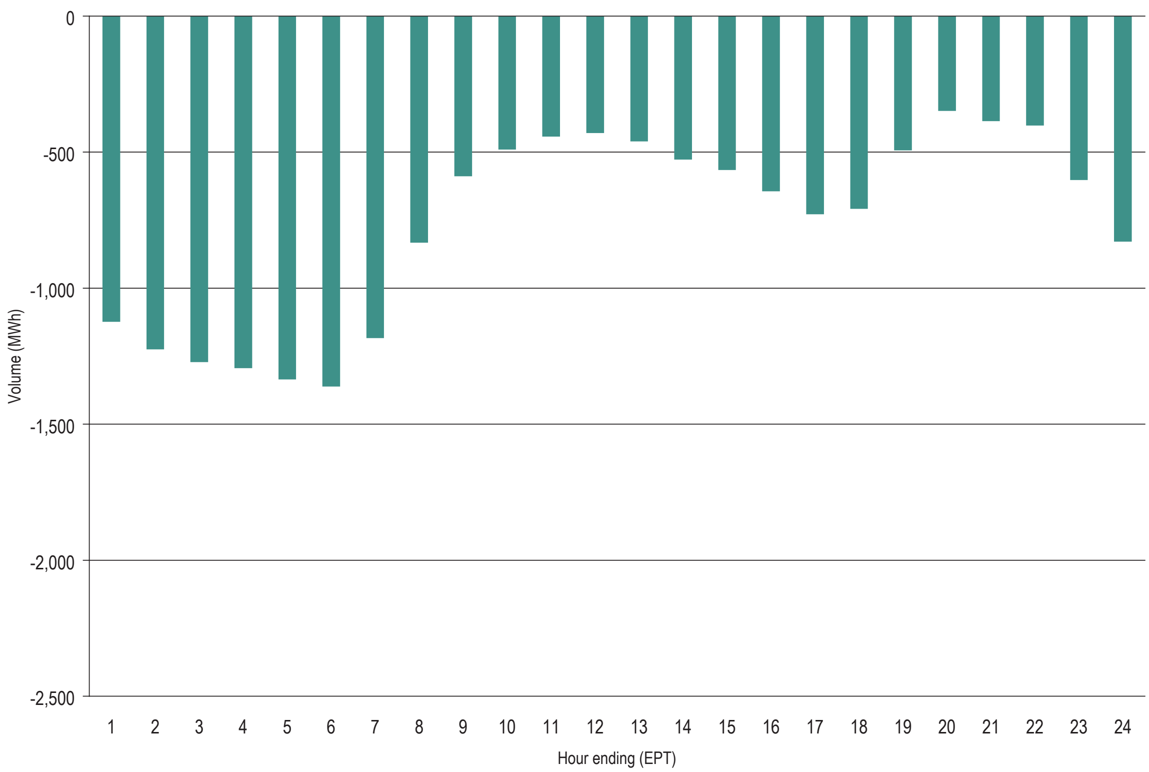
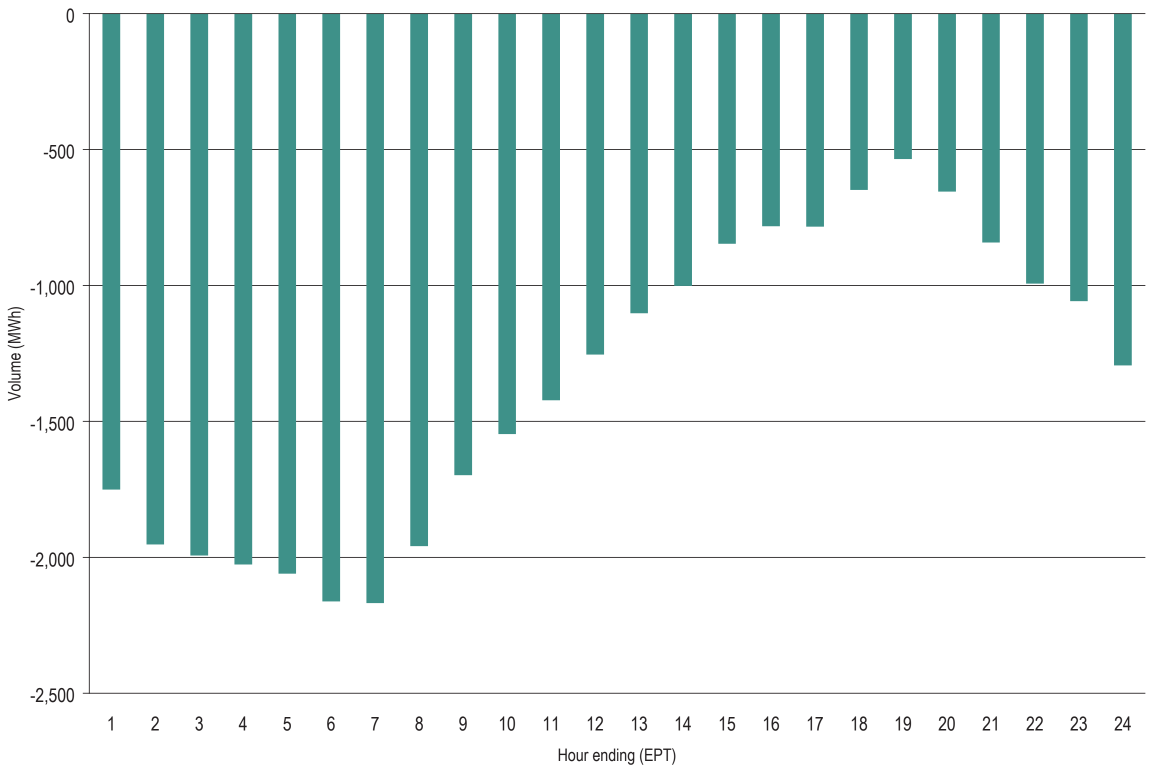


Figure 4-9 - PJM/MECS interface average actual minus scheduled volume: Phase 5



The mismatch became even larger in Phase 5, with the off-peak difference between actual and scheduled flow averaging -1,926 MW compared to -1,203 MW in Phase 4 and the on-peak difference averaging -1,070 MW in Phase 5 compared to -541 MW in Phase 4. The average hourly scheduled exports at the PJM/MECS interface declined from -834 MW per hour in Phase 4 to -147 MW per hour in Phase 5. The actual exports, however, remained relatively unchanged at -1,601 MW per hour in Phase 4 and -1,503 MW per hour in Phase 5. As a result, the difference between actual and scheduled flows increased in Phase 5.

The PJM/TVA interface also exhibited large mismatches between scheduled and actual power flows. The experience at the PJM/TVA interface is different from that at the PJM/MECS interface in that the net difference between scheduled flows and actual flows is imports while the net difference at the PJM/MECS interface is exports. (See Figure 4-10 and Figure 4-11.) Exports are scheduled, but actual flows are imports so the net difference is imports rather than exports. In Phase 4, the average hourly scheduled flow was -354 MW per hour (export) while actual flow was 516 MW per hour (import) for a difference of 870 MW. This general pattern continued in Phase 5, but the difference was larger. In Phase 5 average hourly scheduled flow was -1,157 MW while actual flow was 36 MW, for a difference of 1,193 MW.

The PJM/MECS differences and the PJM/TVA differences are in opposite directions and therefore create loop flow across PJM. The excess of actual over scheduled exports at PJM/MECS is in part met by the excess of actual over scheduled imports at PJM/TVA.

Figure 4-10 - PJM/TVA average flows: Phase 4

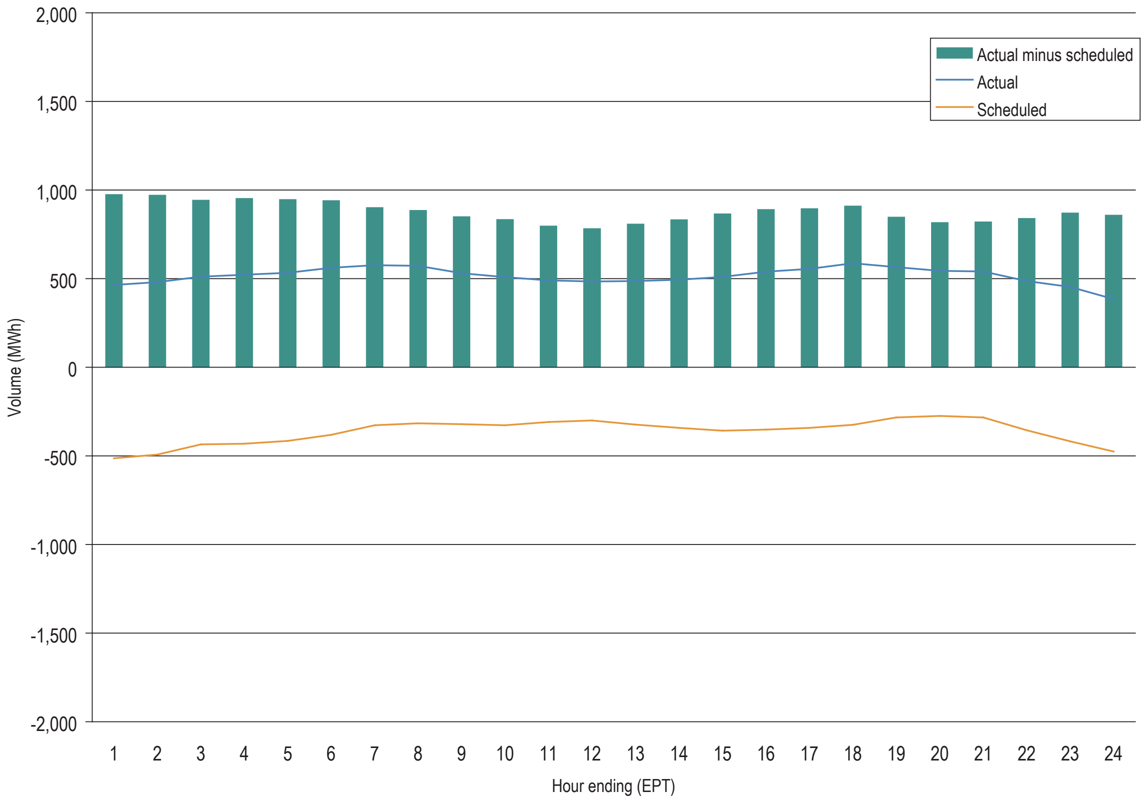
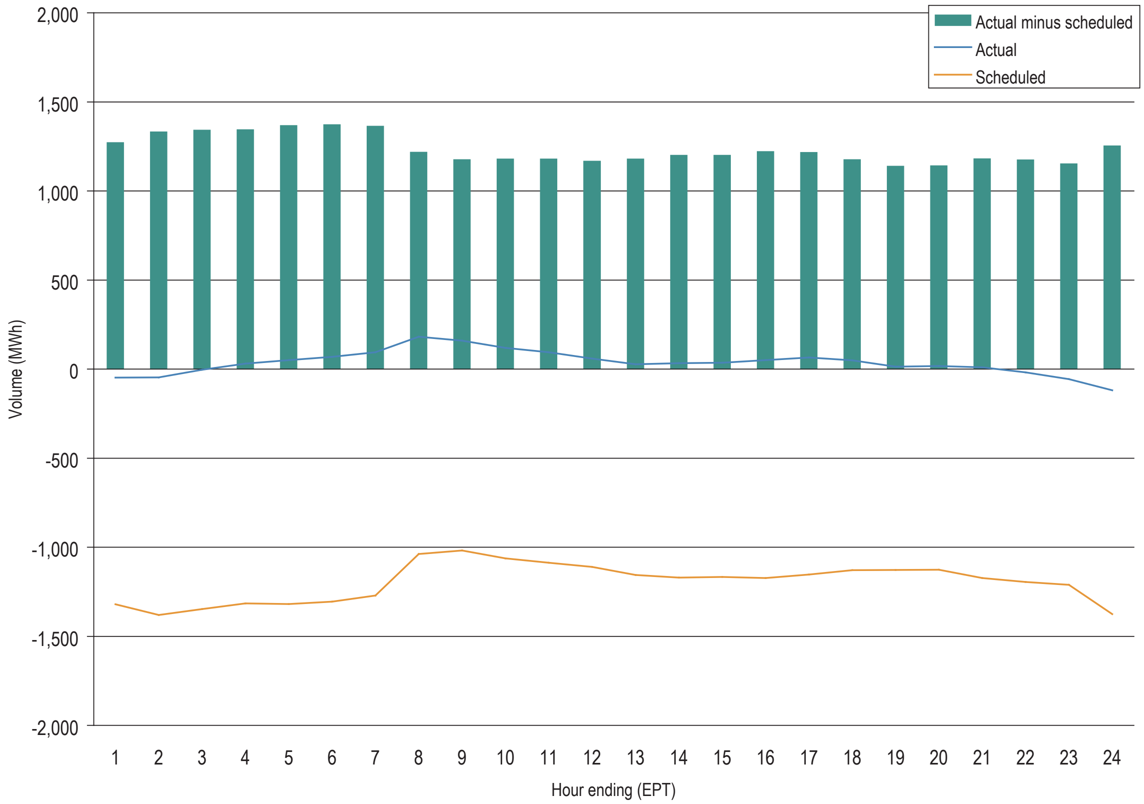


Figure 4-11 - PJM/TVA average flows: Phase 5



The differences between scheduled and actual flows at specific interfaces are a potentially significant concern, constituting unscheduled use of PJM's transmission system, affecting real-time system operations and affecting FTR revenue adequacy because loop flows do not pay congestion costs. The reasons for the identified differences between scheduled and actual flows remain unclear. It would be appropriate for PJM and the Midwest ISO to cooperate in an analysis of the underlying issues in order to identify the sources of loop flow and to create a solution.

Interchange Issues

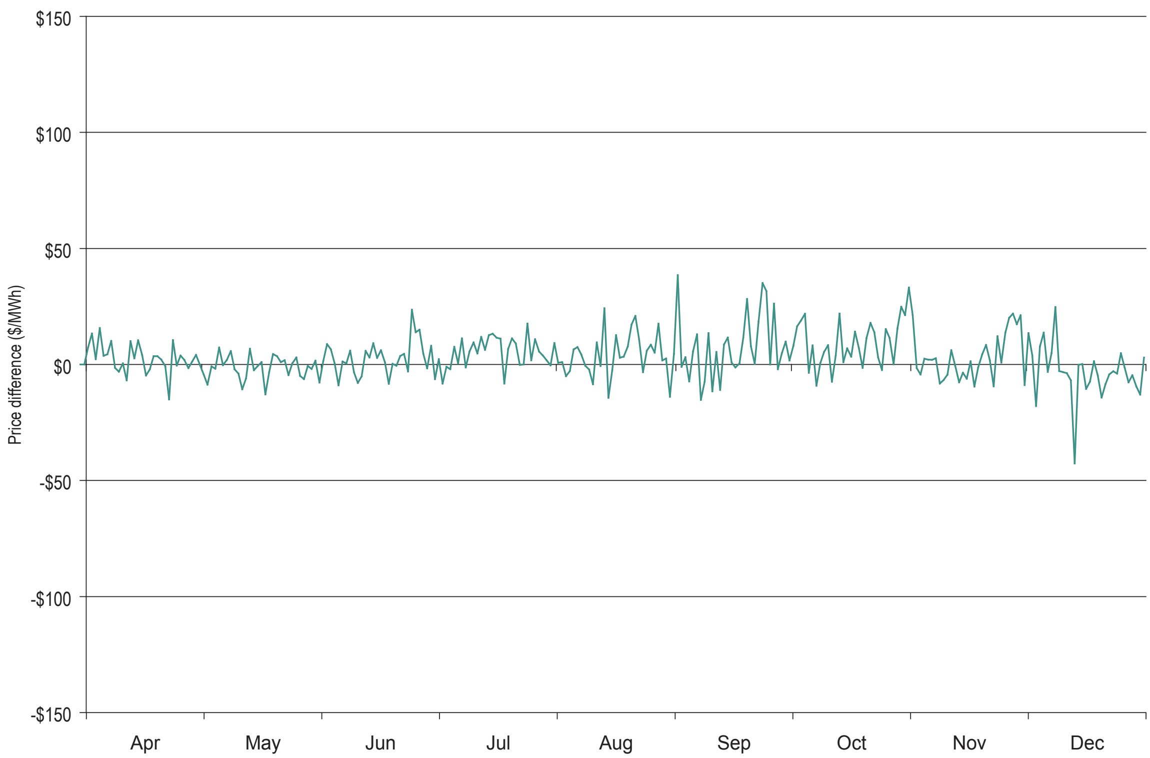
Prices at the borders between PJM and the NYISO and PJM and the Midwest ISO were consistent with competitive pressures. A wheeling contract between New York's Consolidated Edison and New Jersey's PSEG requires involvement from both PJM and NYISO as operators of the relevant transmission facilities. PJM is considering development of rules that would limit a market participant's ability to reserve more ramp than is actually either needed or used to contribute to more efficient use of transmission capability between PJM and surrounding markets.

PJM and Midwest ISO Interface Pricing

On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from Midwest ISO would receive the PJM/MISO price upon entering PJM, while a transaction into Midwest ISO from PJM would receive MISO/PJM price when entering Midwest ISO. PJM and Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[13] within Midwest ISO to calculate the PJM/MISO interface price while Midwest ISO uses all PJM generator buses[14] in its calculation of the MISO/PJM interface price.

The 2005 hourly average prices for PJM/MISO and the MISO/PJM interface price were $48.84 and $52.12, respectively. The simple average difference between the PJM/MISO interface price and the MISO/PJM interface price was $3.28 in 2005, approximately 7 percent of the average PJM/MISO price. (See Figure 4-12.) The MISO/PJM interface price was higher on average than the PJM/MISO price in 2005. The simple average interface price difference does not reflect the underlying hourly variability in prices during 2005.

Figure 4-12 - Daily hourly average price difference (Midwest ISO interface - PJM/MISO): Calendar year 2005



13 See "LMP Aggregate Definitions" <http://www.pjm.com/markets/energy-market/downloads/20060103-aggregate-definitions.xls> (1.33 MB).
14 Based on information obtained from the Midwest ISO Extranet (October 21, 2005) <http://extranet.midwestiso.org/>.

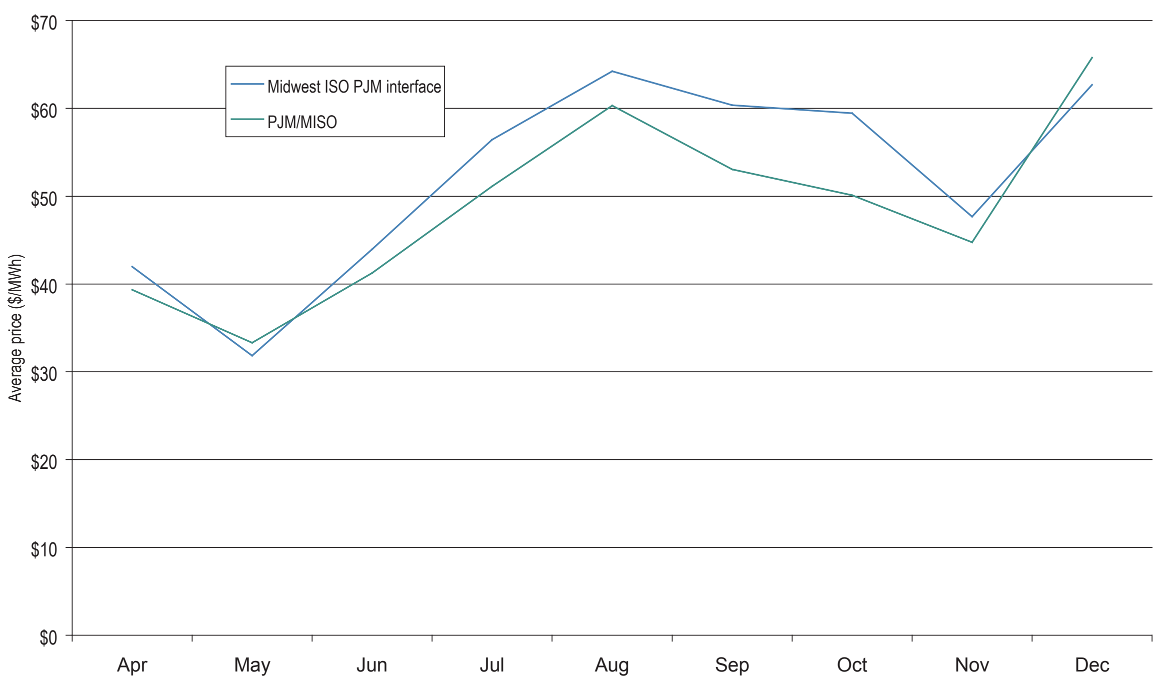
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

During 2005, the difference between the PJM/MISO interface price and the MISO/PJM interface price fluctuated between positive and negative about nine times per day. The standard deviation of hourly price was $31.09 in 2005 for the PJM/MISO price, and $33.25 in 2005 for the MISO/PJM interface price. The standard deviation of the difference in interface prices was $23.30 in 2005. The average of the absolute value of the hourly price difference was $15.49 in 2005. Absolute values reflect price differences regardless of whether they are positive or negative.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between monthly average hourly PJM and Midwest ISO interface prices during the 2005 period. Figure 4-13 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-13 - Monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: Calendar year 2005



PJM and NYISO Interface Pricing

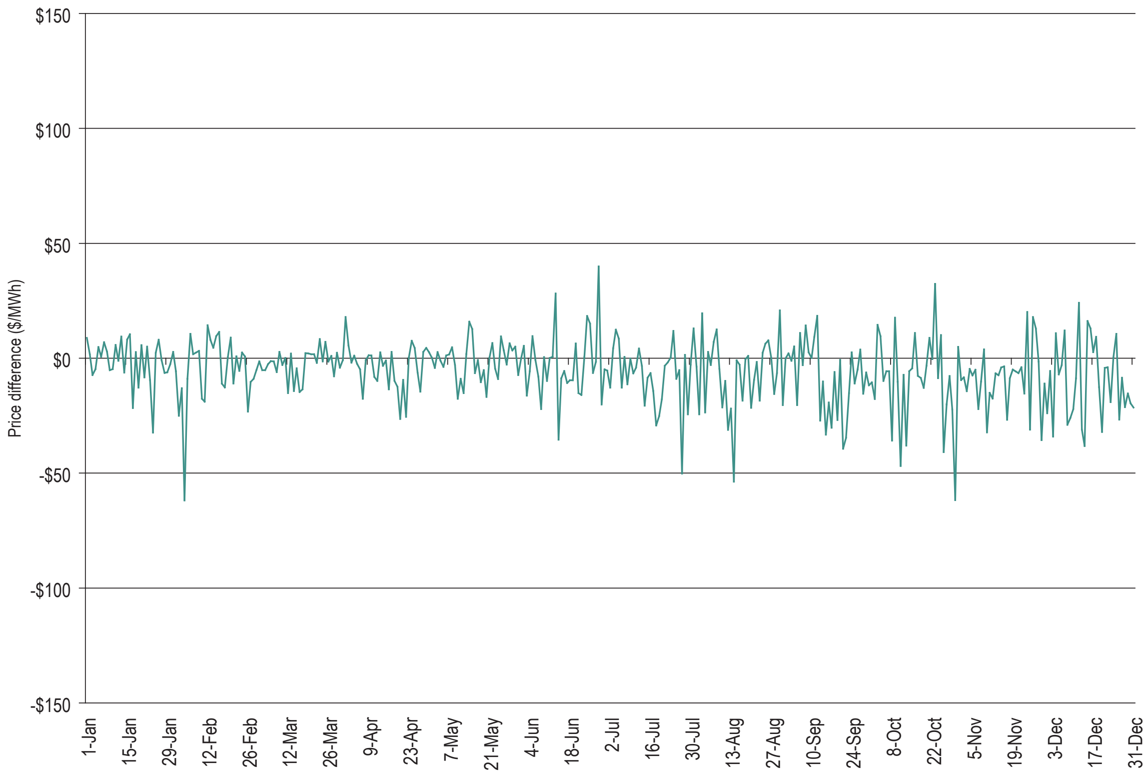
If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[15]

PJM's price for transactions with the NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM market. PJM defines its NYIS pricing point using two buses.[16] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as price-capped load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2005 hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $67.15 and $61.83, respectively. The simple average difference between the PJM/NYIS interface price and the NYISO/PJM proxy bus price increased from -$2.39 per MWh in 2004 to -$5.32 per MWh in 2005 and the variability of the difference also increased. (See Figure 4-14.) The fact that PJM's net export volume to New York for 2005 is 39 percent lower than the four-year, 2001-to-2004 average is at least partially consistent with the fact that the PJM/NYIS price is greater than the NYISO/PJM price and that the difference increased in 2005. The simple average interface price difference does not reflect the continuing, substantial underlying hourly variability in prices during 2004 and 2005.

15 See also the discussion of these issues in the *2003 State of the Market Report*, Section 3, "Interchange Transactions."
16 See PJM's LMP Aggregate Definitions < http://www.pjm.com/markets/energy-market/downloads/20060103-aggregate-definitions.xls> (1.33 MB).

Figure 4-14 - Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2005



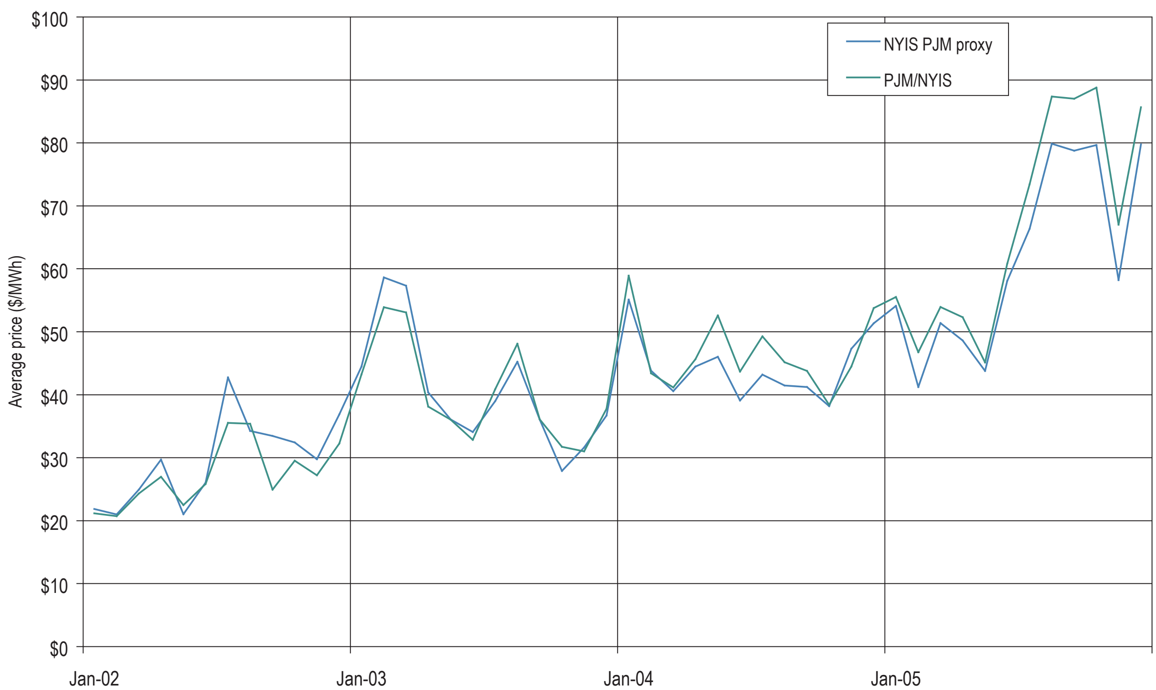
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the PJM/NYIS interface price and the NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2005 as it did in 2003 and 2004. The standard deviation of hourly price was $25.00 in 2003, $23.64 in 2004 and $42.93 in 2005 for the PJM/NYIS price and $37.72 in 2003, $30.00 in 2004 and $41.57 in 2005 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $36.21 in 2003, $29.55 in 2004 and $40.22 in 2005. The average of the absolute value of the hourly price difference was $16.13 in 2003, $14.01 in 2004 and $23.44 in 2005. Absolute values reflect the price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface prices is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.

There is a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2005. Figure 4-15 shows this correlation between hourly PJM and NYISO interface prices.

Figure 4-15 - Monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2005



As previously noted,[17] institutional difference between PJM and NYISO markets partially explain observed differences in border prices. The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market each hour based on hourly bids.[18] Import transactions to NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers, each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. It is a function of time lags built into the functioning of the real-time commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no less than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of NYISO, the price the participants are willing to pay. The required lead-time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

PJM operating practices provide that market participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[19] The duration of

17 See *2003 State of the Market Report*, pp. 105-107; and *2004 State of the Market Report*, pp. 138-140.
18 See "NYISO Transmission Services Manual, Version 2.0" (February 1, 2005) < http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (462 KB).
19 See "PJM Manual 11: Scheduling Operations" (November 9, 2005) < http://www.pjm.com/contributions/pjm-manuals/pdf/m11v26.pdf > (448 KB).

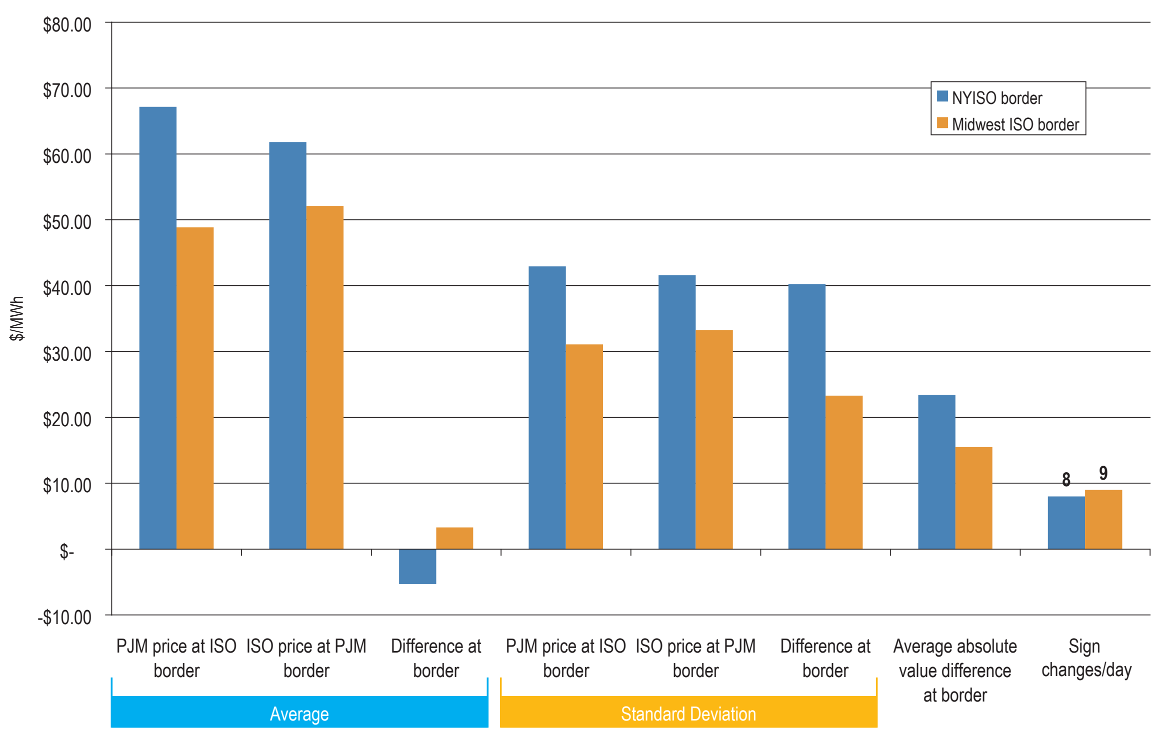
the requested transaction can vary from a single hour to an unlimited amount of time. Generally PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 1 percent of all transactions submit an associated price. Transactions are accepted in order of submission based on whether PJM has the capability to import or export the requested MW. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Market. As in the NYISO, the required lead-time means that participants must make offers to buy or sell MW based on expected prices, but the lead-time is substantially shorter in the PJM market.

The NYISO rules provide that RTC results should be available 45 minutes before the operating hour. Thus winning bidders have 25 minutes from the time when RTC results indicate that their transaction will flow until the time when they must get their transaction cleared with PJM to meet the 20-minute requirement. To get a transaction cleared with PJM, the market participant must have a valid North American Electric Reliability Council (NERC) Tag, an Open Access Same-Time Information System (OASIS) reservation, a PJM schedule and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead-times in both markets could be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-16 including average prices and measures of variability.

Figure 4-16 - PJM, NYISO and Midwest ISO border price averages: Calendar year 2005



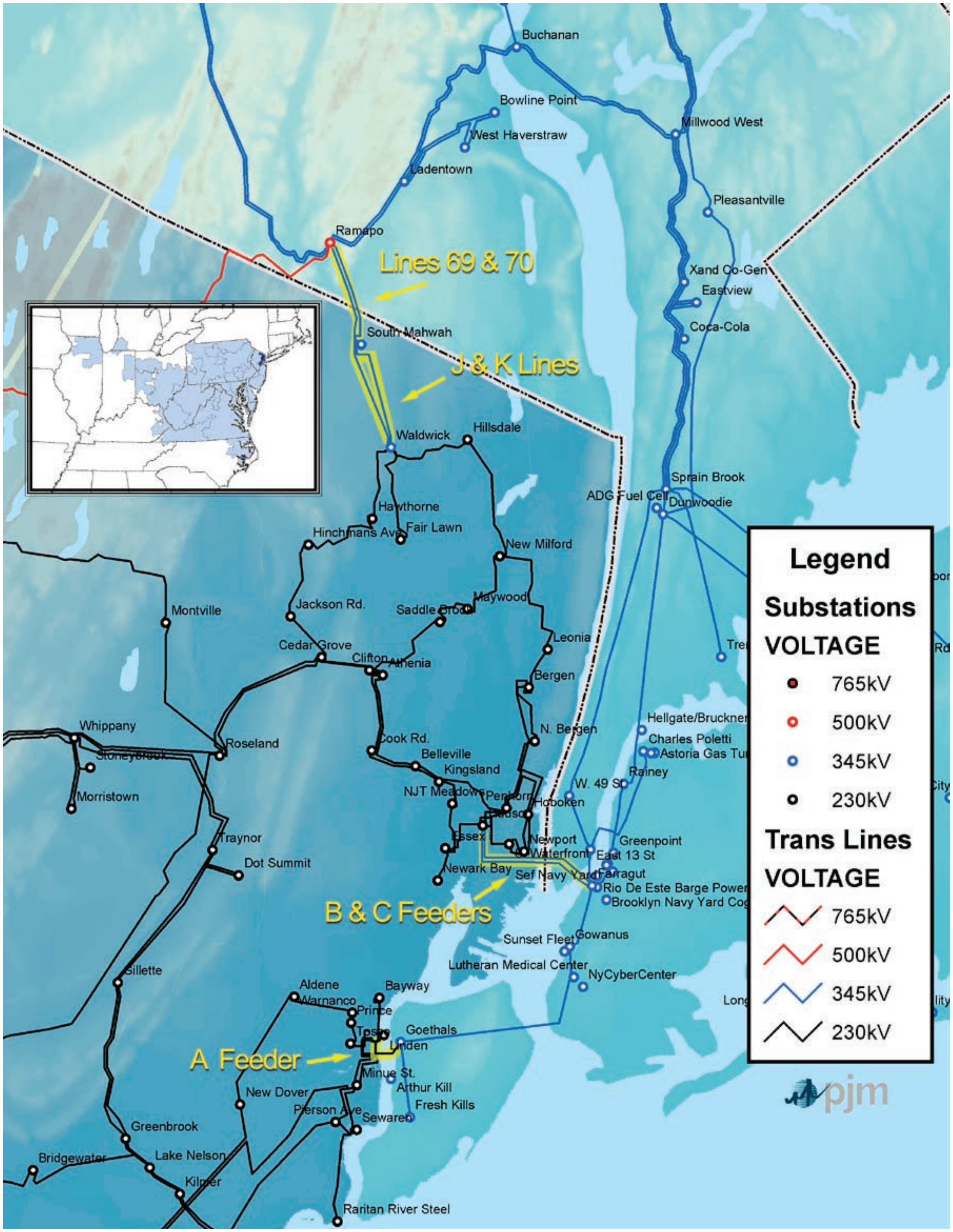
Consolidated Edison Company and PSEG Wheeling Contracts

To help meet the demand for power in New York City, Consolidated Edison Company uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. The Consolidated Edison/PSEG contracts governing the New Jersey path evolved during the 1970s and were the subject of a Consolidated Edison complaint to the FERC in 2001. In July 2005, a FERC-approved protocol was implemented to resolve the matter. Based on the experience to date, Consolidated Edison has made formal recommendations to increase delivery performance.

Background

The contracts provide for the delivery of up to 1,000 MW of power from Consolidated Edison's Ramapo Substation in Rockland County, New York to PSEG at its Waldwick Switching Substation in Bergen County, New Jersey. PSEG then wheels the power across its system and delivers it back to Consolidated Edison across lines connecting directly into the city. (See Figure 4-17.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSEG's Waldwick Switching Station (New Jersey) then to New Milford Switching Station (New Jersey) via the J line and ultimately from Linden Switching Station (New Jersey) to Goethals Substation (New York) and from Hudson Generating Station (New Jersey) to Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Consolidated Edison alleged that PSEG had underdelivered on the agreements and asked the FERC to resolve the issue.

Figure 4-17 - Consolidated Edison and PSEG wheel



In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[20] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Consolidated Edison to elect up to the contracted flow under each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSEG to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Consolidated Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSEG is assigned FTRs associated with the 600 MW contract. The PSEG FTRs are treated like all other FTRs. For the six-month period, PSEG's FTR revenues were less than the associated congestion charges by $2.1 million because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Consolidated Edison receives credits on an hourly basis for up to the amount of its congestion charges associated with its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. For the six-month period, Consolidated Edison's congestion credits were less than the associated congestion charges by $8.2 million. (See Table 4-7.)

20 111 FERC ¶ 61,228 (2005).

Table 4-7 - Consolidated Edison and PSEG wheel settlements data: July through December 2005

		Consolidated Edison			PSEG		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
July	Congestion Charge	$1,170,519.50	$9,347.11	$1,179,866.61	$1,843,902.00		$1,843,902.00
	Congestion Credit			$500,826.79			$1,805,338.00
	Net Charge			$679,039.82			$38,564.00
August	Congestion Charge	$810,156.00	($344.54)	$809,811.46	$1,215,234.00		$1,215,234.00
	Congestion Credit			$487,697.85			$1,204,398.08
	Adj. (July)						($7,229.66)
	Net Charge			$322,113.61			$18,065.58
September	Congestion Charge	$2,185,169.20	($6,757.30)	$2,178,411.90	$3,524,946.00		$3,524,946.00
	Congestion Credit			$477,322.41			$3,010,261.74
	Adj. (August)						$82.65
	Net Charge			$1,701,089.49			$514,601.61
October	Congestion Charge	$3,589,016.12	$386,018.03	$3,975,034.15	$5,668,896.00	$28,576.01	$5,697,472.01
	Congestion Credit			$341,601.81			$4,639,686.70
	Adj. (September)						$1,140.07
	Net Charge			$3,633,432.34			$1,056,645.24
November	Congestion Charge	$697,700.00	$282,714.23	$980,414.23	$1,088,712.00		$1,088,712.00
	Congestion Credit			$143,173.40			$856,827.21
	Adj. (October)			($17,330.68)			($26,088.71)
	Net Charge			$854,571.51			$257,973.50
December	Congestion Charge	$1,143,544.00		$1,143,544.00	$1,715,316.00		$1,715,316.00
	Congestion Credit			$159,398.53			$1,492,410.30
	Adj. (November)						$365.50
	Net Charge			$984,145.47			$222,540.20
Total	Congestion Charge	$9,596,104.82	$670,977.53	$10,267,082.35	$15,057,006.00	$28,576.01	$15,085,582.01
	Congestion Credit			$2,110,020.79			$13,008,922.03
	Adj.			($17,330.68)			($31,730.15)
	Net Charge			$8,174,392.24			$2,108,390.13

The Real-Time Energy Market Process

Under the terms of the protocol, Consolidated Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. As a general matter, this has not occurred.

Market Monitoring

The FERC order asked the market monitors for both PJM and NYISO to evaluate their ability to perform investigations ensuring that neither gaming nor abuse of market power occur. The PJM MMU has seen nothing during the protocol's initial six-month period that would require the MMU to gather data outside the bounds of the order.

In addition, the MMU has evaluated conduct under the protocol and has not identified the exercise of market power by either participant.

Consolidated Edison Company September 2005 Status Report

On September 30, 2005, in compliance with the May 2005 FERC order, Consolidated Edison filed a status report with the FERC in which it criticized PJM and NYISO for performance under the protocol, but expressed a willingness to work with both to address areas of concern. PJM has increased operator training, PJM and NYISO hold weekly meetings to review protocol performance and to discuss operational issues and any open items and system software improvements are under development that will aid in the operation of the protocol.

Ramp and Transmission Reservation Issues

PJM limits the amount of change in net interchange, or ramp, between 15-minute intervals in order to ensure compliance with NERC performance standards. Any market participant wishing to initiate (or change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first come, first served basis, up to the ramp limit.

There are several issues associated with ramp rules. Ramp rules do not appear to provide adequate time to submit transactions to replace transactions that have been forced to expire. As a more general matter, ramp rules do not appear to provide adequate incentives for the efficient use of ramp. Ramp rules also permit the submission of transactions solely to create ramp room in the opposite direction. While these issues have arisen and been addressed on a case by case basis, neither PJM nor the MMU have assessed the overall extent or impact of the identified issues.

While ramp limits may be modified by PJM depending on system conditions, the limit is generally 1,000 MW for imports and exports for all hours. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions is -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15-minute period did not exceed 1,000 MW in either direction.

Market participants at times request and receive ramp reservations that are not used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations. This behavior can reflect attempts to manipulate PJM prices, to disadvantage competitors or simply mistakes by participants. To help ensure efficient use of available ramp, PJM rules force unused ramp reservations to expire 30 minutes before they are scheduled to flow if they are not backed up with an actual energy transaction. This leaves only 10 minutes for another participant to request the ramp because PJM rules require that transactions be submitted only up to 20 minutes prior to the scheduled start time for hourly transactions.[21] While this rule contributes to the efficient use of ramp, given that it requires time to assemble the components of a transaction, the existing rules may free unused ramp when it is too late for other market participants to make effective use of it. In other words, ramp reservations become available with little time for others to use them and can effectively block other participants from the market.

It is possible for participants to hold transmission service reservations for relatively long periods without using it, making it unavailable for efficient use. Market participants may make OASIS reservations for daily firm transmission at the earliest possible time allowed under PJM rules (i.e., by 1400 hours three business days before the start date) and hold such a reservation without taking any action to create a corresponding transaction. As the participant does not have to pay for the reservation, there is no incentive to release it.

PJM rules permit the artificial creation of ramp room using a ramp reservation in the opposite of the desired direction. This approach may be used to create apparent ramp room in the desired direction. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp. The participant would also request an import reservation. Ultimately, the import transaction would flow and the export reservation would not be used to export energy, expiring 30 minutes prior to flow.

These problems can be addressed by modifications to PJM rules. A possible solution to the expiration timing rules would be to set different time limits for reservations. For example, if less than 24 hours remain between the times when a reservation is requested and when the transaction will flow, then a reservation not backed up by a scheduled transaction could have a shortened time limit between time of request and automatic expiration. The time period could be extended for requests made more than 24 hours in advance. Such a procedure would require market participants to either complete their transaction or make the ramp available to other participants.

21 See "PJM Manual 11: Scheduling Operations" (November 9, 2005), p. 99 < http://www.pjm.com/contributions/pjm-manuals/pdf/m11v26.pdf > (448 KB).