SECTION 5 - ANCILLARY SERVICE MARKETS

The FERC defined six ancillary services in Order 888: 1) scheduling, system control and dispatch service; 2) reactive supply and voltage control from generation sources service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve - spinning reserve service; and 6) operating reserve - supplemental reserve service.[1] Of these, PJM currently provides regulation and spinning through market-based mechanisms. PJM also provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes). Longer term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Spinning reserve is a form of primary reserve. To provide spinning a generator must be synchronized to the system and capable of providing output within 10 minutes.

Both the Regulation and Spinning Reserve Markets are cleared on a real-time basis. A unit can be selected for either spinning reserve or regulation or neither, but it cannot be selected for both. The Spinning Reserve and Regulation Markets are cleared simultaneously and cooptimized with the Energy Market to minimize the cost of the combined products.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[3] Generation owners are paid according to the FERC-approved reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1**. The four-month period from January 1 through April 30, 2004, when PJM was comprised of 12 zones.[4] Eleven of these [i.e., 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)] comprised the Mid-Atlantic Region. The remaining zone, the Allegheny Power Company Control Zone (AP), comprised the PJM Western Region.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.
3 See "PJM Manual for Scheduling Operations, M-11," Revision 22 (October 19, 2004), p. 71.
4 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The 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 the 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.

- **Phase 2.** 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).[5]

- **Phase 3.** 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.

In Phase 1 of 2004, PJM operated two Regulation Markets: one for the Mid-Atlantic Region and a second for the AP Control Zone. For Phase 2 a third market was added for the ComEd Control Area. For Phase 3, PJM operated two Regulation Markets, one for the Mid-Atlantic Region and one for the Western Region now comprised of the AP, ComEd, AEP and DAY Control Zones.

In Phase 1, PJM operated two Spinning Reserve Markets: one for the Mid-Atlantic Region and a second for the AP Control Zone. For Phase 2, a third market was added for the ComEd Control Area. For Phase 3, PJM operated three Spinning Reserve Markets in three spinning zones: the PJM Mid-Atlantic Region spinning zone, the ComEd spinning zone and the AP-AEP-DAY spinning zone.

Overview

The PJM Market Monitoring Unit (MMU) has reviewed structure, conduct and performance indicators for the identified Regulation Markets and the Spinning Reserve Markets. The MMU concludes that the markets functioned effectively, except for the Regulation Market in the Phase 2 ComEd regulation zone, and produced competitive results during calendar year 2004, in every case including ComEd. The issue in the ComEd regulation zone was inadequate available supply of regulation during some hours. Clearing prices in the ComEd Regulation Market were consistent with a competitive outcome as the market was cleared on the basis of cost-based offers.

Before the Phase 2 integration of ComEd and the Phase 3 integrations of the AEP and DAY Control Zones, PJM operated separate Regulation Markets and the Spinning Reserve Markets in the PJM Mid-Atlantic Region and in the AP Control Zone.[6] The market analysis treats each Regulation Market and each Spinning Reserve Market separately for these periods.

The structure of each of the Regulation and Spinning Reserve Markets has been evaluated and the MMU has concluded that, with the exception of the Regulation Market in the PJM Mid-Atlantic Region, these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these Ancillary Service Markets are operated as markets with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. The conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive.

5 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).
6 The PJM Mid-Atlantic Region is in the Mid-Atlantic Area Council (MAAC) region of the North American Electric Reliability Council (NERC), the AP, AEP and DAY Control Zones of the PJM Western Region are in the East Central Area Reliability Council (ECAR) NERC region, and the ComEd Control Zone is in the Mid-America Interconnected Network, Inc. (MAIN) NERC region. MAAC, ECAR and MAIN have different reliability requirements for the two services. These requirements are documented in the business rules for each market, located in the "PJM Manual for Scheduling Operations, M-11" (October 19, 2004).

The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' price offers during Phases 1, 2 and 3. All suppliers were paid the market-clearing price, which is a function of the supply curve and PJM-defined demand. The supply curve is offered MW and their associated offer price, which is a combination of unit-specific offers plus opportunity cost (OC)[7] as calculated by PJM. The Regulation Market in the AP Control Zone during Phases 1 and 2 was cleared on cost-based offers because, given a single regulation supplier, the market was not structurally competitive. The price of regulation in the AP Control Zone was based on unit-specific, cost-based offers plus unit-specific opportunity cost. The Regulation Market in the ComEd Control Area during Phase 2 was cleared on cost-based offers as the market was not structurally competitive. The cost-based regulation offer prices are defined to be the unit-specific incremental cost of providing regulation plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

The geographic scope of the Regulation Market was redefined for Phase 3 as two Regulation Markets, one for the Mid-Atlantic Region and one for the Western Region comprised of the AP, ComEd, AEP and DAY Control Zones. In Phase 3, the PJM Western Region's Regulation Market was cleared on cost-based offers as the market was not structurally competitive.

During 2004, the Spinning Reserve Markets in the PJM Mid-Atlantic Region and in the ComEd spinning zone were cleared based on cost-based offers because these markets were determined to be not structurally competitive. The cost-based offers for spinning reserve include incremental cost plus a margin and opportunity cost. The price of spinning in the AP Control Zone was based on unit-specific cost-based offers. Prices for spinning in the PJM Mid-Atlantic Region and the ComEd spinning zone were market-clearing prices determined by supply and PJM-defined demand. The cost-based spinning offers are defined to be the unit-specific incremental cost of providing spinning reserve plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

Regulation Market Structure

- **Concentration of Ownership**. During 2004, the PJM Mid-Atlantic Region's Regulation Market had an average Herfindahl-Hirschman Index (HHI) of 1608 which is classified as "moderately concentrated."[8,9] Less than 1 percent of the hours had a single pivotal supplier. During Phases 1 and 2 of the year, there was only one supplier of regulation in the Western Region. In Phase 2, the ComEd Control Area was a separate Regulation Market with an average HHI of 5817, meaning that the market was highly concentrated. In Phase 3, the AP, ComEd, AEP and DAY Control Zones became a single Regulation Market, with an average HHI of 3426. In Phase 3, ownership of regulation in the PJM Western Region's Regulation Market was highly concentrated. There was a single pivotal supplier in 56 percent of the hours.

Regulation Market Performance

- **Price**. The average price per MWh associated with meeting PJM's demand for regulation during 2004 remained about the same as it had been in 2003, approximately $42.75 per MWh. The average cost per MWh in the AP regulation zone during Phases 1 and 2 was $33.71 per MWh, an increase of 34 percent.

7 As used here, the term "opportunity cost" (OC) refers to the estimated lost opportunity cost (LOC) that PJM uses to create a supply curve on an hour-ahead basis. The term, "lost opportunity cost," refers to opportunity costs included in payments to generation owners.
8 See Section 2, "Energy Market" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
9 The HHIs reported in this summary are based on regulation capacity that is both offered to the market and is eligible to provide regulation.

The average price per MWh for regulation in the ComEd Control Area during Phase 2 was $39.22. Intraday regulation prices varied widely in the ComEd Control Area primarily because of insufficient regulation capacity during times of minimum generation and times when the requirement was 300 MW.

For the PJM Western Region regulation zone during Phase 3, the average price per MWh for regulation was $18.36.

- **Availability**. The supply of regulation in the PJM Mid-Atlantic Region was both stable and adequate, with a 2.90 average ratio of hourly regulation supply offered to the hourly regulation requirement. This average ratio was 1.68 for the ComEd Control Area's Phase 2 Regulation Market and 2.12 for the Western Region's Phase 3 Regulation Market.

  While the average ratio of hourly regulation supply offered to the hourly regulation requirement was 1.68, the situation was more complicated in the ComEd Control Area during Phase 2. Regulation capacity was always adequate in the sense that the total reported capability was adequate.[10] However, there was inadequate regulation that was both offered and eligible to participate in the market on an hourly basis to meet the on-peak requirement of 300 MW during May, June and July. This situation was alleviated in August after the regulation certification of additional generating units.

Spinning Reserve Market Structure

- **Concentration of Ownership**. In 2004, market concentration was high in the Tier 2 Spinning Reserve Market. The average spinning market HHI for the PJM Mid-Atlantic Region throughout 2004 was approximately 3100. During Phases 1 and 2 of the year, the AP Control Zone had only one supplier of spinning reserve. During Phases 2 and 3, the Spinning Reserve Market in the ComEd spinning zone had only two suppliers and an HHI of approximately 8181. During Phase 3, the AP-AEP-DAY spinning zone had an HHI of 5648.[11]

Spinning Reserve Market Performance

- **Price**. Average price associated with meeting the PJM system demand for spinning reserve throughout 2004 was about $14.86 per MW, a $0.66 per MW decrease from 2003. The average price in the AP Control Zone for Phases 1 and 2 was $33.37 per MW for a 27 percent increase compared to 2003. This increase was caused by higher fuel costs in the AP Control Zone and was reflected in the cost-based bids of the units. The average price for spinning reserve in the ComEd spinning zone during Phases 2 and 3 was $17.21. The average price for spinning in the AP-AEP-DAY spinning zone during Phase 3 was $12.24.

10 See "Regulation Capacity, Daily Availability, Hourly Supply and Price," in Appendix F, "Ancillary Service Markets," for a definition of capacity, availability and supply.
11 This portion of the Spinning Reserve Market ended the calendar year comprised of the AP, AEP and DAY Control Zones. For clarity, it is referred to herein as the AP-AEP-DAY spinning zone.

Regulation Market

Regulation Market Structure

Demand

Demand for regulation is price inelastic as it does not change with price for regulation. The demand for regulation is set administratively based on reliability objectives. In some PJM Regulation Markets demand varies with overall load, and in other PJM Regulation Markets demand is fixed regardless of market conditions.

The PJM Mid-Atlantic Region has different regulation requirements for on-peak hours and off-peak hours. The regulation requirement for the peak period is 1.1 percent of the peak-load forecast; for the off-peak period, it is 1.1 percent of the valley-load forecast.[12] On October 22, 2004, the PJM Mid-Atlantic Region's regulation requirement was temporarily increased by 175 MW for both on-peak and off-peak periods. On December 16, 2004, the PJM Mid-Atlantic Region's regulation requirement was reduced from this level by 50 MW. During Phases 1 and 2, PJM Mid-Atlantic Region regulation requirements ranged from 215 MW of regulation capability for off-peak periods to 583 MW for on-peak periods. During Phase 3, requirements ranged from 227 MW of regulation capability for off-peak periods to 659 MW for on-peak periods.[13]

In the AP Control Zone, the regulation requirement was 1.0 percent of the peak forecast load and did not vary between on-peak and off-peak periods. During Phases 1 and 2, the requirement ranged from 53 MW to 82 MW.

In the ComEd Control Area during Phase 2, the regulation requirement was 300 MW during weekday hours ending 0000, 0100, 0700, 0800, 0900 and 2300 EPT although it was not possible to actually assign 300 MW of regulation until mid-August 2004 because it was not available. For all other hours, the requirement was 150 MW.

During Phase 3, the PJM Western Region had a regulation requirement of 1 percent of the forecast peak load. On October 22, 2004, the Western Region regulation zone's regulation requirement was increased to 1 percent of the forecast peak load plus 175 MW. In the third week of December, the Western Region regulation zone's regulation requirement was reduced to 1 percent of forecast peak load plus 125 MW. The Western Region regulation zone requirement during Phase 3 ranged from 303 MW to 635 MW.

Regulation obligation is determined hourly for each load-serving entity (LSE) by applying the real-time load ratio share (adjusted for scheduled load responsibility) to the actual amount of regulation assigned for that hour adjusted for any bilaterals and self-supply. The hourly regulation charge for each LSE is equal to the hourly regulation market-clearing price (RMCP) multiplied by the MW of regulation purchased from the market, plus the LSE's percentage share of any opportunity cost incurred by generation owners over and above the RMCP, plus the LSE's percentage share of any unrecovered costs incurred by those units the regional transmission organization (RTO) called on for the sole purpose of providing regulation.

12 See "PJM Manual for Scheduling Operations, M-11," Revision 22 (October 19, 2004), pp. 50 - 51.
13 For additional detail, please refer to Appendix F, "Ancillary Service Markets."

Supply

The supply of regulation can be measured as regulation capability, regulation offered, regulation offered and eligible, or regulation assigned. For purposes of evaluating the Regulation Market, the relevant regulation supply is defined as the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. The level of supply that clears in the market on an hourly basis is assigned regulation.

Regulation capability represents the total volume of regulation capability reported by resource owners based on unit characteristics.

Regulation offered represents the level of regulation capability actually offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers may be submitted on a daily basis and these daily offers may be modified on an hourly basis.

Regulation offered and eligible represents the level of regulation capability actually offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit will be included in regulation offered based on the daily offer and availability status, but that regulation capability will not be eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market software.) As another example, the regulation capability of a unit will be included in regulation offered if the owner of a unit offers regulation, but that regulation capability will not be eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit will be included in regulation offered but that regulation capability will not be eligible if the unit is not operating, unless the unit is a combustion turbine that meets specific operating parameter requirements.

Only those offers which are eligible to provide regulation in an hour are part of supply for that hour, and only those offers are considered for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market-clearing mechanism to provide regulation service for a given hour.

Market Concentration

PJM Mid-Atlantic Regulation Market – Calendar Year 2004

In the 2004 Regulation Market in the Mid-Atlantic Region, the submitted capability[14] was 2,140 MW with an average daily offer[15] volume of 1,543 MW, or approximately 72 percent of the submitted capability. In the 2004 Regulation Market in the Mid-Atlantic Region, the level of regulation resources

14 Submitted capability is defined as the maximum daily offer volume during the period without regard to the actual availability of the resource.
15 Average daily offer volume is defined for the period, includes units offered for the day and excludes resources which are unavailable on a daily basis.

offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the market were lower than the total level of regulation resources offered. In 2004 the average hourly offer level was 1,170 MW for the Mid-Atlantic Region's Regulation Market while the average hourly eligible offer level was 948 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 2.90 for the PJM Mid-Atlantic Region in 2004. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Based upon regulation offered and eligible, this ratio averaged 2.33. The average regulation requirement for the PJM Mid-Atlantic Region during 2004 was 418 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible, and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 2151 to a minimum of 1097 with an average value of 1546. Based upon regulation offered and eligible, HHI values ranged from a maximum of 2770 to a minimum HHI of 1088, with an average value of 1608. Based upon regulation assigned, HHI values ranged from a maximum of 7256 to a minimum HHI of 1226. The average HHI value for regulation assigned was 2511.

Table 5-1 - PJM hourly Regulation Market HHI: Calendar year 2004

	Minimum	Average	Maximum
Offered	1097	1546	2151
Eligible	1088	1608	2770
Assigned	1226	2511	7256

During 2004, there was one supplier with a market share in excess of 20 percent for regulation offered. That market share was 24.5 percent. There was one supplier with a market share of 20 percent based on regulation offered and eligible. There were two suppliers with a market share in excess of 20 percent based on assigned regulation, with the largest market share 27.1 percent.

During 2004, less than 1 percent of the hours had an RSI value less than 1.0 for offered supply. In terms of offered and eligible supply, 3 percent of the hours had an RSI value less than 1.0. An RSI value less than 1.0 indicates that the market had a single pivotal supplier. The offer of a single pivotal supplier is required in order to clear the market and that pivotal supplier therefore has market power. While the RSI is not a bright line test, these results are consistent with multiple pivotal suppliers and a competitive outcome.

Table 5-2 - PJM hourly Regulation Market RSI statistics: Calendar year 2004

	Percent of Hours RSI < 1.10	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Offered	0%	0%	2.18	0.89
Eligible	6%	3%	1.79	0.52

Based on these market structure data, the MMU concludes that the market structure of the PJM Mid-Atlantic Region's Regulation Market is consistent with a competitive outcome. The market in the PJM Mid-Atlantic Region is currently operated by PJM as a competitive market.

ComEd Regulation Market – Phase 2

During the Phase 2 Regulation Market in the Com Ed Control Area, the submitted capability was 487 MW with an average daily offer volume of 296 MW[16] or approximately 60 percent of the submitted capability. The level of resources offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the Regulation Market were lower than the total level of regulation resources offered. During Phase 2, the average hourly offer level was 276 MW while the average hourly eligible offer level was 260 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 1.68 for the Phase 2 ComEd Regulation Market. Based upon regulation offered and eligible, this ratio averaged 1.57. The average regulation requirement for the ComEd Control Area during Phase 2 was 176 MW.[17]

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 10000 to a minimum of 5000 with an average value of 5713. Based upon regulation offered and eligible, HHI values ranged from a maximum of 10000 to a minimum HHI of 5000, with an average value of 5817. Based upon regulation assigned, HHI values ranged from a maximum of 10000 to a minimum HHI of 5000. The average HHI value for regulation assigned was 7195.

Table 5-3 - ComEd Control Area hourly Regulation Market HHI: Phase 2, 2004

	Minimum	Average	Maximum
Offered	5000	5713	10000
Eligible	5000	5817	10000
Assigned	5000	7195	10000

During Phase 2, there were two suppliers with a market share in excess of 20 percent for regulation offered. The largest such market share was 68.4 percent. There were two suppliers with market shares in excess of 20 percent based on offered and eligible regulation. The largest such market share was 69 percent. There were two suppliers with a market share in excess of 20 percent based on regulation assigned. The largest such market share was 77.2 percent.

During Phase 2, 99.9 percent of the period was characterized by a residual supplier index (RSI) of less than 1.0 for regulation offered and for regulation offered and eligible. An RSI value less than 1.0 indicates that the market was characterized by a single pivotal supplier. The offer of a single pivotal supplier is required in order to clear the market, and that pivotal supplier, therefore, has market power.

16 This level of participation is slightly higher than the 55 percent level reported by the Market Monitor in his October 1, 2004, Declaration (paragraph 46). The Declaration can be found at <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20041004-public-market-based-rates.pdf> (6.8 MB). The calculation in the Declaration was based upon the offer volume as a percentage of the pre-integration stated regulating capability of resources, as provided by the owners, rather than the actual maximum market offer levels used here.
17 See Appendix F, "Ancillary Service Markets," for additional detail on the regulation requirements.

A lack of supply diversity and low offer volume contributed to the concentration levels indicated by the observed HHI and RSI values.

Table 5-4 - ComEd Control Area hourly Regulation Market RSI statistics: Phase 2, 2004

	Percent of Hours RSI < 1.10	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Offered	100%	100%	0.53	0
Eligible	100%	100%	0.49	0

Based on this market structure data, the MMU concludes that the market structure of the ComEd Control Area was not consistent with a competitive outcome. The Regulation Market in the ComEd Control Area was operated by PJM as a cost-based market with market-clearing prices.

PJM Western Region Regulation Market – Phase 3

The PJM Western Region's Regulation Zone during Phase 3 was comprised of the ComEd, AEP, DAY and AP Control Zones. In the Phase 3 Regulation Market in the PJM Western Region, the submitted capability was 1,815 MW with an average daily offer volume of 1,399 MW, or approximately 77 percent of the submitted capability. In the Phase 3 Regulation Market in the PJM Western Region, the level of resources offered on an hourly level and both offered and eligible to participate on an hourly basis in the Regulation Market was lower than the level of regulation resources offered. During Phase 3, the average hourly offer level was 958 MW while the average hourly eligible offer level was 881 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 2.12. Based upon regulation offered and eligible, this ratio averaged 1.93. The average regulation requirement for the PJM Western Region during Phase 3 was 476 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 4318 to a minimum of 2335 with an average value of 3262. Based upon regulation offered and eligible, HHI values ranged from a maximum of 5648 to a minimum HHI of 2283, with an average value of 3426. Based upon regulation assigned, HHI values ranged from a maximum of 10000 to a minimum of 2209. The average HHI value for regulation assigned was 4012.

Table 5-5 - Western Region hourly Regulation Market HHI: Phase 3, 2004

	Minimum	Average	Maximum
Offered	2335	3262	4318
Eligible	2283	3426	5648
Assigned	2209	4012	10000

During Phase 3, there were two suppliers with a market share in excess of 20 percent for offered supply. The largest market share for offered regulation was 47.9 percent. There were two suppliers with market shares in excess of 20 percent for regulation offered and eligible. The largest market share for regulation offered and eligible was 51 percent. There were two suppliers with a market share in excess of 20 percent for regulation assigned. The largest market share for regulation assigned was 47.9 percent.

During Phase 3 in the Western Region, 56 percent of the hours had a residual supplier index (RSI) less than 1.0 for regulation offered. For regulation offered and eligible, 78 percent of the Phase 3 hours had an RSI value less than 1.0.

Table 5-6 - Western Region hourly Regulation Market RSI statistics: Phase 3, 2004

	Percent of Hours RSI < 1.10	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Offered	64%	56%	1.11	0.66
Eligible	86%	78%	0.95	0.59

Based on these market structure data, the MMU concludes that the market structure of the PJM Western Region was not consistent with a competitive outcome. The Regulation Market in the PJM Western Region is currently operated by PJM as a cost-based market with market-clearing prices.

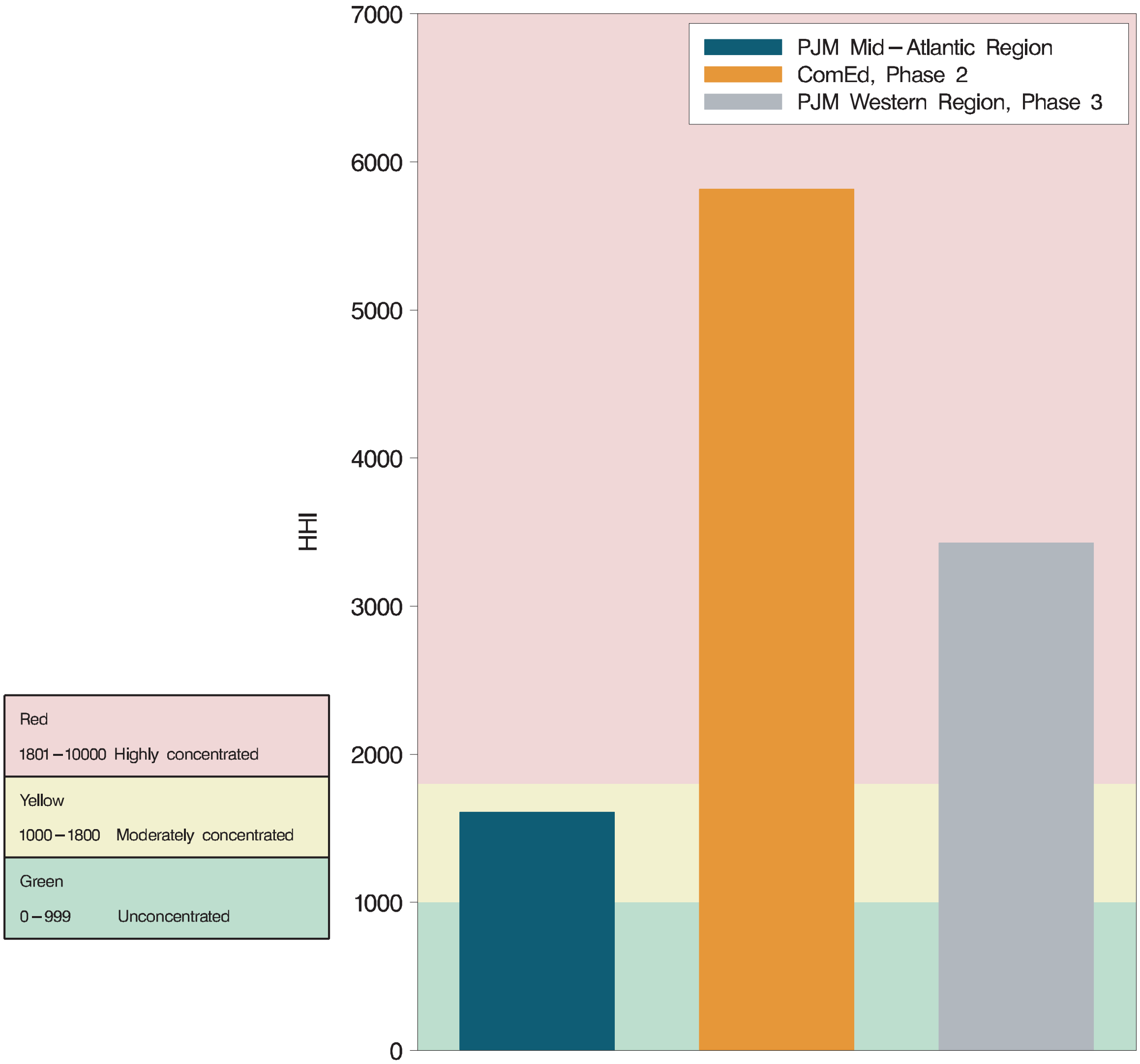
On October 1, 2004, the PJM Market Monitor filed with the FERC a Declaration regarding the expected competitiveness of the Regulation Market in the PJM Western Region. For that analysis, the MMU gathered data on regulation capability from the generators in the Western Region and cross-checked the data against other available sources. The data available at that time reflected the regulation capability reported by generation owners that had not yet been validated in actual market operation within PJM or been subjected to PJM tests of regulation capability. The MMU analyzed the Regulation Market configuration consistent with the Commission's April 14, 2004, order.[18] The data reported in the Declaration indicated a regulation capability in the PJM Western Region of 1,977 MW. It was assumed for purposes of analysis in the Declaration that all regulation capability would be offered to the market.

Actual market regulation capability, regulation offered and regulation offered and eligible during Phase 3 were below the regulation capability reported in the Declaration. The level of market participation in the Western Region during Phase 3 averaged approximately 77 percent of the regulation capability. This is similar to the results during 2004 in the PJM Mid-Atlantic Region's Regulation Market where approximately 72 percent of the total regulation capability was offered into the market. Though the level of participation is similar, different patterns of ownership in the Western Region resulted in higher market concentration levels and lower RSI levels in the Western Region than in the PJM Mid-Atlantic Region.

18 107 FERC¶ 61,018 (2004); see also 107 FERC ¶ 61,026 (2004).

Summary of Market Concentration

Figure 5-1 - PJM system Regulation Market HHI: Calendar year 2004



HHI levels during calendar year 2004 in the PJM Mid-Atlantic Region's Regulation Market were 1608 on average, based on regulation offered and eligible which is at the upper end of the moderately concentrated designation under the FERC "Merger Policy Statement."[19] HHI levels during Phase 2 in the ComEd Control Area's Regulation Market were 5817 on average, based on regulation offered and eligible, or highly concentrated. HHI levels during Phase 3 in the PJM Western Region's Regulation Market were 3426 on average, based on regulation offered and eligible, or highly concentrated. (See Figure 5-1.)

19 See Section 2, "Energy Markets," at "Market Concentration" for a discussion of HHI.

Regulation Market Performance

Regulation Offers

Generators wishing to participate in any of the PJM Regulation Markets submitted regulation offers for specific units by hour 1800 EPT of the day before the operating day. The regulation offer price is subject to a $100 per MWh offer cap in the PJM Mid-Atlantic Region and a cost plus $7.50 per MWh offer cap elsewhere, with the exception of the AP Control Zone during Phases 1 and 2. In the AP Control Zone during Phases 1 and 2, regulation offers were capped at the cost of providing regulation service because there was only one regulation supplier. The AP zone's regulating units were compensated at their individual regulation offer plus LOC rather than at a single market-clearing price.

The offer price is the only component of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status; regulation capability; and high and low regulation limits. The Regulation Market is cleared on a real-time basis, and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made 30 minutes before each operating hour.

The Regulation Market in the PJM Mid-Atlantic Region (calendar year 2004), in the AP Control Zone (Phases 1 and 2), in the ComEd Control Area (Phase 2) and in the PJM Western Region (Phase 3) was cleared hourly, based upon both offers submitted by the units and the hourly opportunity cost of each unit.[20] The effective offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks the units by effective offer price and selects in order until the amount of regulation required for the hour is satisfied at least cost. The price that results in the required amount of regulation is the regulation market-clearing price (RMCP), and the unit that sets this price is the marginal unit.

Regulation Prices

Figure 5-2 shows both the daily average regulation market-clearing price and the opportunity cost for the marginal units in the PJM Mid-Atlantic Region during calendar year 2004. Figure 5-3 shows the same data for the ComEd Control Area's Regulation Market during Phase 2 and for the PJM Western Region's regulation zone during Phase 3. All units chosen to provide regulation in the PJM Mid-Atlantic Region and in the ComEd regulation zone during Phase 2 received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation bid multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[21] Units in the AP Control Zone during Phases 1 and 2 were compensated at the unit's own cost plus the actual lost opportunity cost of the unit while providing that regulation. The AP Control Zone did not have a market-clearing price.

20 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. Opportunity cost is included in the market-clearing price.

21 See "PJM Operating Agreement, Accounting, m28," Revision 27, Section 4, "Regulation Credits" (October 1, 2004), pp. 26-27. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and spinning. Real-time opportunity cost is calculated using real-time LMP.

Figure 5-2 - PJM Mid-Atlantic Region daily average regulation clearing price and estimated opportunity costs: Calendar year 2004

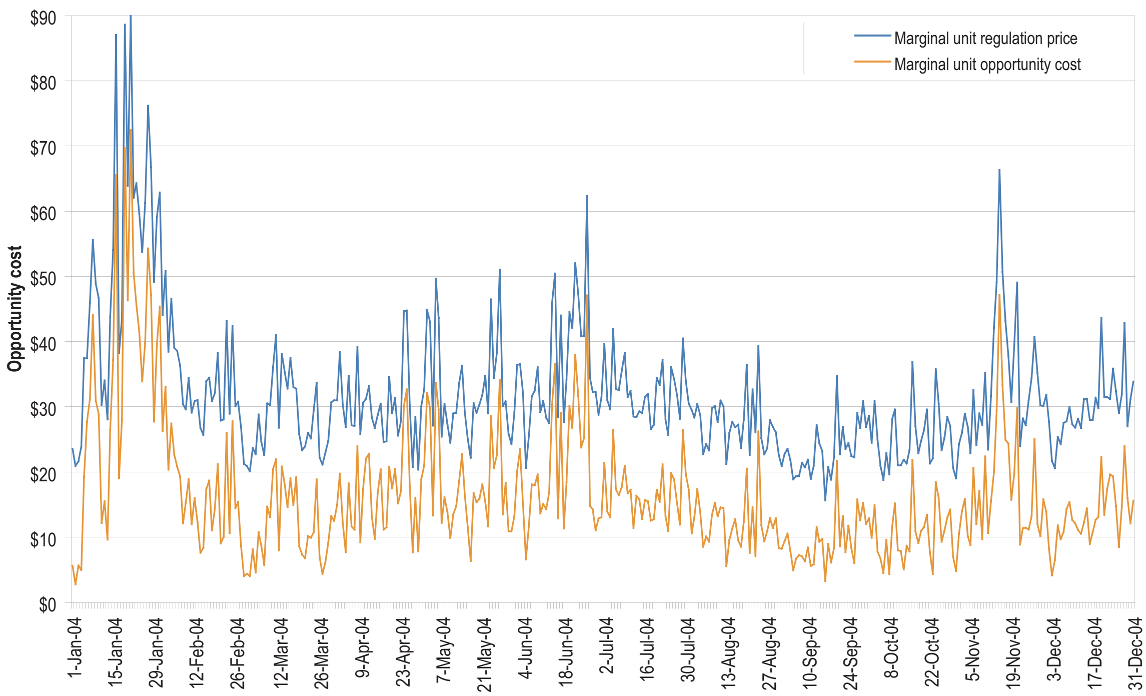
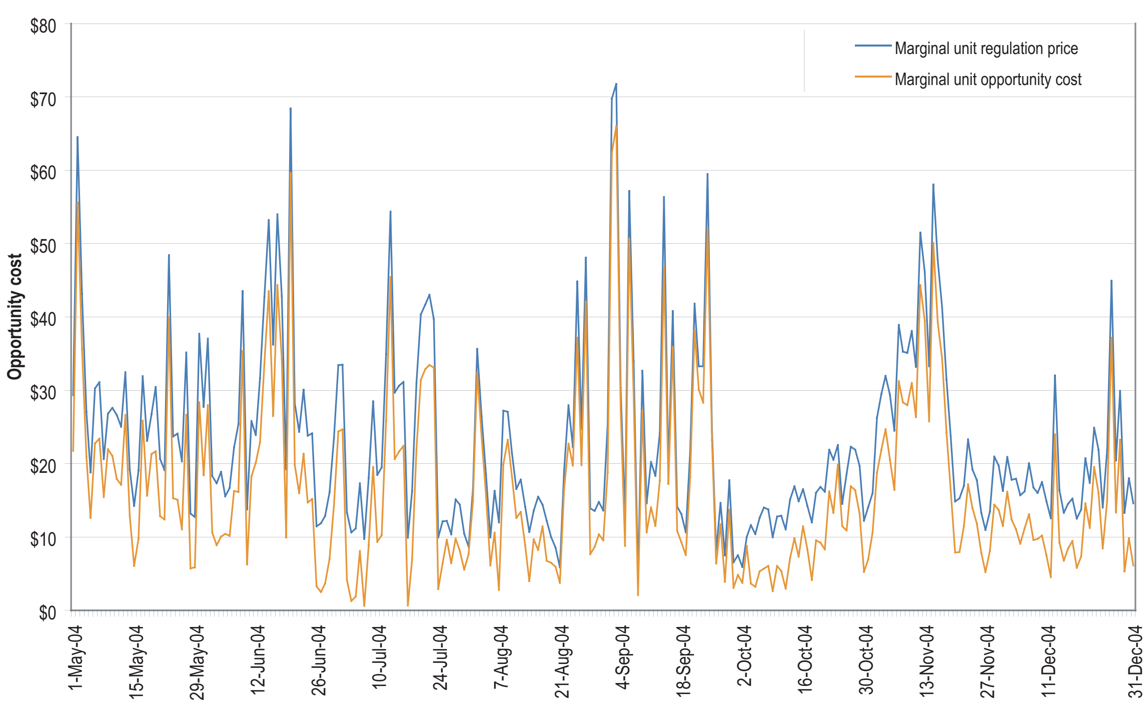


Figure 5-3 - ComEd (Phase 2) / Western Region (Phase 3) daily average regulation clearing price and opportunity costs: Phases 2 and 3, 2004



As Figure 5-4 shows, during calendar years 2003 and 2004, hourly regulation prices in the PJM Mid-Atlantic Region were relatively stable despite several significant, short-term spikes in the price of regulation during February 2004 that resulted from price spikes in the Energy Market affecting the regulation price via the OC.

Figure 5-4 - PJM Mid-Atlantic Region daily regulation MW purchased vs. price per MW: March 1, 2003, to December 31, 2004

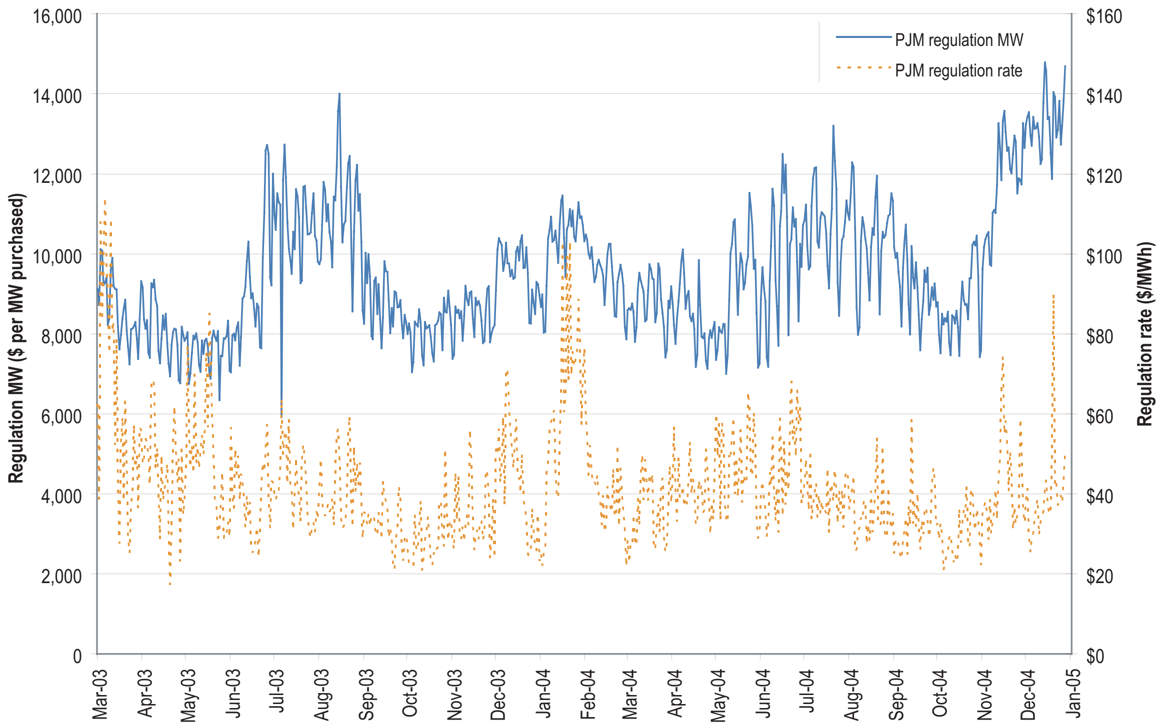
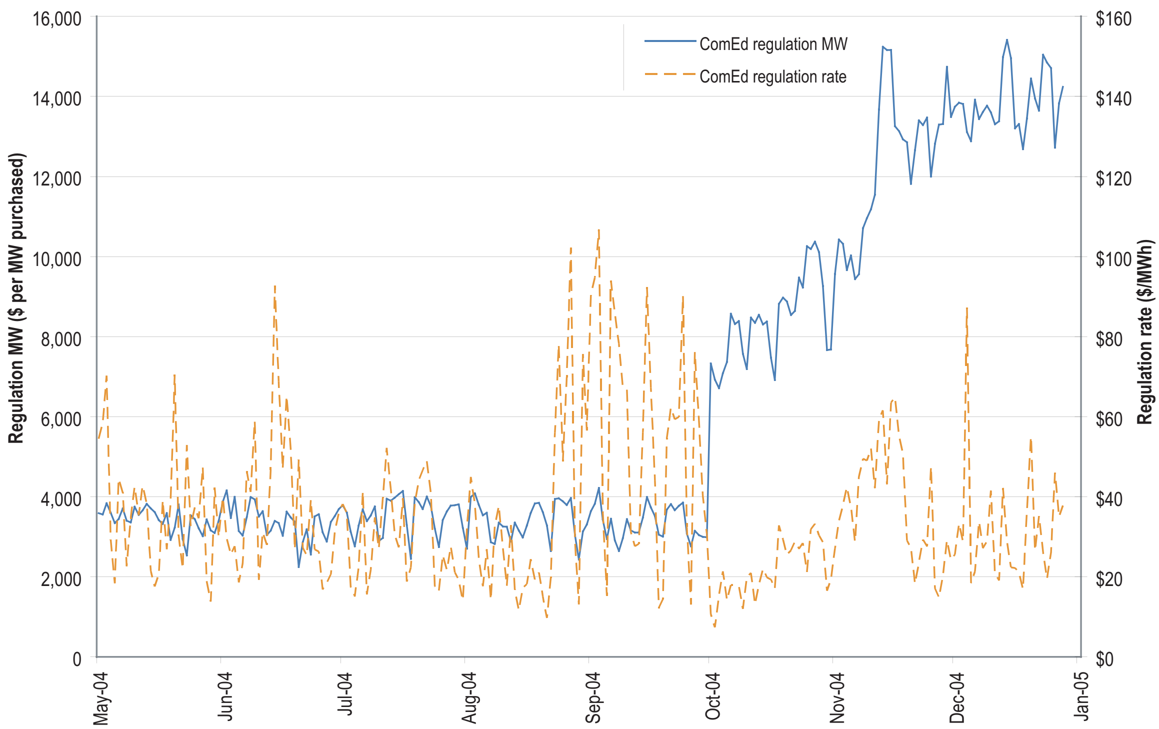


Figure 5-4 compares the regulation price per MWh for the PJM Mid-Atlantic Region to the demand for regulation for the calendar years 2003 and 2004. In the PJM Mid-Atlantic Region, the price of regulation has tended to follow system locational marginal energy price (LMP). Demand for regulation is a linear function of forecasted energy demand. When loads increase, the result is an increase in demand for regulation. System LMP increases with load because higher priced units must be dispatched to meet demand. Increases in system LMP cause the opportunity cost to rise by increasing the spread between LMP and the energy offers of the regulating units. As a result, load, energy prices and regulation prices are highly correlated.

Figure 5-5 compares the regulation price for the ComEd Control Area to the demand for regulation during Phase 2. The graph displays the same data for the newly configured PJM Western Region's Regulation Market during Phase 3. During Phase 2, PJM fixed demand for regulation in the ComEd regulation zone at 300 MW during weekday hours ending 0000, 0100, 0700, 0800, 0900 and 2300 EPT. For all other hours, the requirement was 150 MW. For this reason, in the ComEd regulation zone the relationship between the price of regulation and the price of energy was not the same as in the PJM Mid-Atlantic Region. More important in ComEd were the regulation supply and the cost of supplying regulation. For the first three to four months after becoming part of PJM, the ComEd regulation zone did not have enough regulation available hourly to meet demand. This limitation forced PJM to dispatch additional generation capable of regulation so as to meet demand for regulation. Furthermore, at times of minimum generation, some regulating units had to be taken offline to prevent an overgeneration imbalance. In late August 2004, additional regulation capability was added in the ComEd regulation zone. Overall, the inflexibility of demand and the shortage of available regulating units caused relatively wide price swings in the ComEd Control Area during Phase 2.

Figure 5-5 - ComEd (Phase 2) / Western Region (Phase 3) daily regulation MW purchased vs. cost per MWh: Phases 2 and 3, 2004



The price of regulation for the PJM Mid-Atlantic Region was approximately the same in Phases 1 and 2, 2004 (i.e., $42.75 per MWh) as it had been in 2003 (i.e., $42.30 per MWh). During Phase 3, the price of regulation for the PJM Mid-Atlantic Region was $38.26 per MWh. The average price of regulation in the PJM Mid-Atlantic Region for calendar year 2004 was $41.48 per MWh. In the AP Control Zone during Phases 1 and 2, the price of regulation was 30 percent higher than it had been in 2003 ($33.71 per MWh compared to $25.15 per MWh). The higher regulation prices in AP for 2004 were the result primarily of higher fuel prices. For the ComEd Control Area during Phase 2, the price of regulation was $39.22 per MWh. For the PJM Western Region's Regulation Market during Phase 3, the average price of regulation was $31.14 per MWh.

Regulation Availability

During the market-clearing process, the PJM Market Operations Group assigns all regulation in economic order until the amount of required regulation is satisfied. If there is a lack of capacity because of unit maintenance or unit unavailability, market operations staff can call on units that have not been scheduled for generation in order to satisfy regulation requirements. If regulating MW needed to meet the requirement remain unavailable, market operations reports this condition to PJM dispatching operations and a regulation deficit occurs.

The PJM Mid-Atlantic Region almost never experienced a deficit of regulation during calendar year 2004. In fact, the Mid-Atlantic Region experienced a regulation deficit during only 0.2 percent of all hours during Phases 1 and 2 and during only 3.8 percent of all hours during Phase 3. The AP Control Zone during Phases 1 and 2 had regulation deficits during 6.5 percent of all hours. The ComEd Control Area during Phase 2 had regulation deficits during 19 percent of all hours. These deficits occurred for several reasons, including a shortage of regulation-certified units during the first two months of Phase 2 and unavailable regulation units. Seventy-four percent of these regulation deficits occurred during on-peak hours when regulation demand was higher while 26 percent of these regulation deficits occurred during off-peak hours. In ComEd a relatively large percentage of lower priced generating units were not capable of regulation and, during times of minimum generation, units capable of regulation were not available. By mid-August 2004, additional regulation capability entered the market, alleviating the shortage and increasing regulation prices. The PJM Western Region during Phase 3 had regulation deficits during only 0.2 percent of all hours.

Spinning Reserve Market

Spinning Reserve Market Structure

Supply

Spinning reserve is an ancillary service defined as generation that is synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can, at present, be provided by a number of sources, including steam units with available ramp, condensing hydroelectric units, condensing CTs and CTs running at minimum generation.

All of the units that participate in the Spinning Reserve Market are categorized as either Tier 1 or Tier 2 spinning. Tier 1 resources are those units that are online following economic dispatch and able to respond to a spinning event by ramping up from their present output. All units operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 spinning. Tier 2 resources include units that are backed down to provide spinning capability and condensing units synchronized to the system and available to increase output.

PJM introduced a market for spinning reserve on December 1, 2002. Before the Spinning Reserve Market, Tier 1 spinning reserve had not been compensated directly and Tier 2 spinning reserve had been compensated on a unit-specific, cost-based formula.

Under the Spinning Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed. Tier 1 spinning payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the spinning energy premium less the hourly integrated LMP. The spinning energy premium is defined as the average of the five-minute LMPs calculated during the spinning event plus $50 per MWh.[22] All units called on to supply Tier 1 or Tier 2 spinning have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response. Tier 2 units assigned spinning by market operations are compensated whether or not they are actually called on to supply spinning so they are penalized if their MW output fails to meet their assignment.

There were significant changes to the geographic structure of PJM's Spinning Reserve Markets in 2004. In Phase 1, PJM had two Spinning Reserve Markets: the PJM Mid-Atlantic Region and the AP Control Zone. In Phase 2, the ComEd spinning zone was created, resulting in three separate Spinning Reserve Markets. In Phase 3, AEP and DAY were integrated and PJM was divided into three separate Spinning Reserve Markets: the Mid-Atlantic Region's, ComEd's and the AP-AEP-DAY Western Region's Spinning Reserve Markets.

Under the Spinning Reserve Market rules, Tier 2 spinning resources are paid in order to be available as spinning reserve, regardless of whether the units are called upon to generate in response to a spinning event. The price for Tier 2 spinning resources is determined in a market for Tier 2 spinning resources. Several steps are necessary before the hourly Tier 2 Spinning Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. If spinning requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit order price of the highest price, Tier 2 resource needed to fulfill spinning requirements, the marginal unit. A unit's merit order price is a combination of the unit's spinning offer price, the cost of energy use per MWh of capability and the unit's opportunity cost.[23]

The spinning offer price submitted for a unit can be no greater than the maximum value of the unit's operating and maintenance cost plus a $7.50 per MWh margin.[24,25] The market-clearing price is comprised of the marginal unit's offer price, cost of energy use and opportunity cost. All units cleared in the Spinning Reserve Market are paid the higher of either the market-clearing price or the unit's spinning offer plus the unit-specific LOC and cost of energy use incurred. The Mid-Atlantic Region's Tier 2 Spinning Reserve Market is cleared on cost-based offers because the structural conditions for competition do not exist. The structural issue can be more severe when the Spinning Reserve Market becomes local because of transmission constraints.

22 See "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), pp. 66-67.
23 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price is established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.
24 See "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), p. 58.
25 See PJM Manual 15: Cost Development Guidelines, Rev. 4, (September 1, 2004), p. 31.

The AP-AEP-DAY Western Region spinning reserve zone and the ComEd spinning reserve zone operate under business rules that are similar to those in the Mid-Atlantic Region. The Spinning Reserve Markets in the AP-AEP-DAY Western Region spinning reserve zone and the ComEd spinning reserve zone are cleared on cost-based offers because there are not enough suppliers to support a competitive market for these services.

Demand

Tier 2 spinning requirements are determined by subtracting the amount of Tier 1 spinning available from the total control area spinning reserve requirement for the period. Total spinning reserve requirement is different for each of the three spinning reserve ancillary service markets. For the Mid-Atlantic Region's spinning reserve zone, the requirement is 75 percent of the largest contingency on the PJM system, provided that 25 percent of the largest contingency is available as nonsynchronized, 10-minute reserve. For the ComEd spinning reserve zone, the requirement is 50 percent of ComEd's load ratio share of the largest contingency in the MAIN NERC region. From October 1 to December 3, 2004, this was computed to be 269 MW. After December 3, the ComEd spinning requirement was recomputed to be 216 MW. For the AP-AEP-DAY Western Region spinning reserve zone, the requirement is 1.5 percent of the daily peak-load forecast.

Figure 5-6 - PJM Control Area average hourly required spinning vs. Tier 2 spinning purchased: Calendar years 2003 to 2004

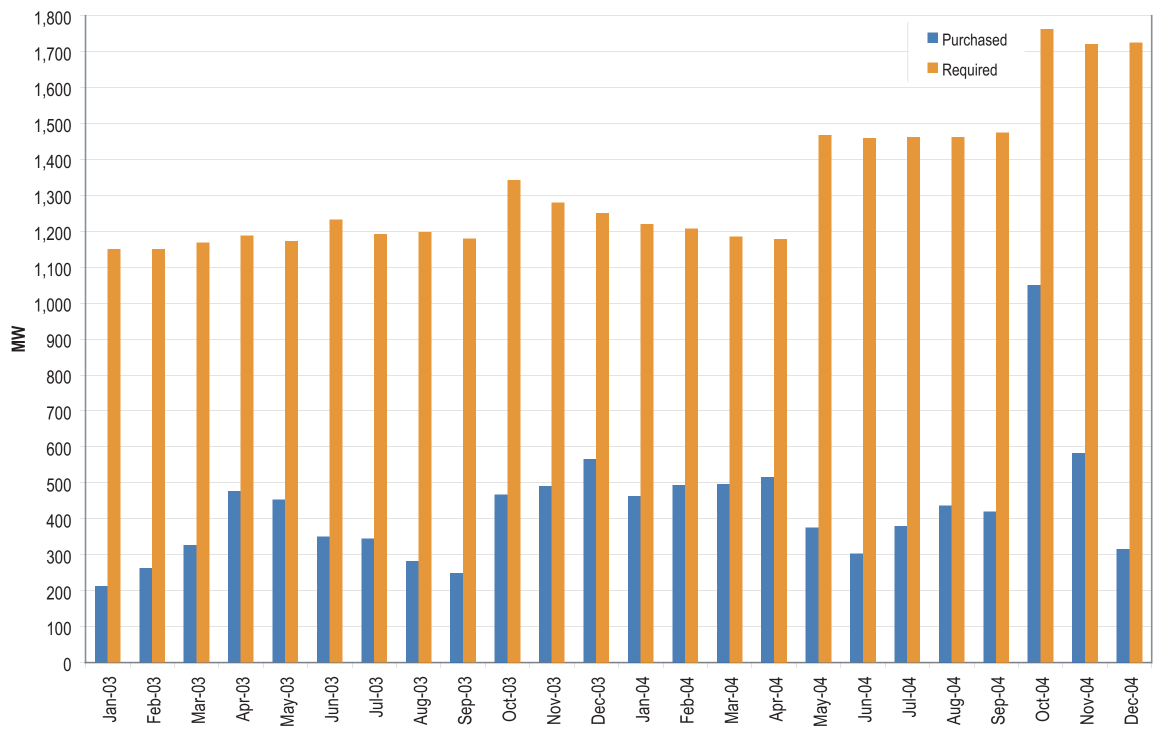
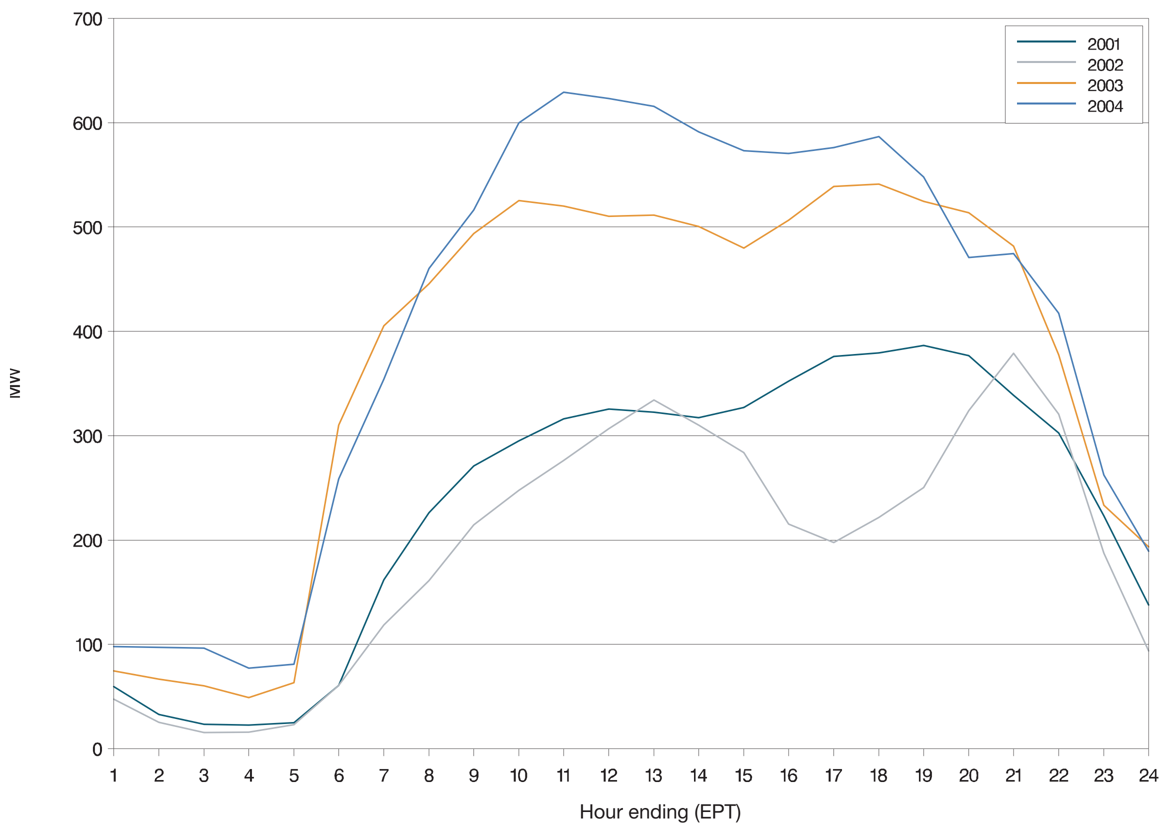


Figure 5-6 shows the annual average hourly Tier 2 spinning MW that PJM purchased during 2003 and 2004 across all spinning zones. Tier 2 spinning MW requirements and purchases were higher in the last quarter of 2003 than they had been during prior years because a disturbance control standard (DCS) violation in July 2003 increased spinning requirements. Tier 2 spinning MW requirements increased in 2004 as the result of the Phase 2 and 3 integrations.

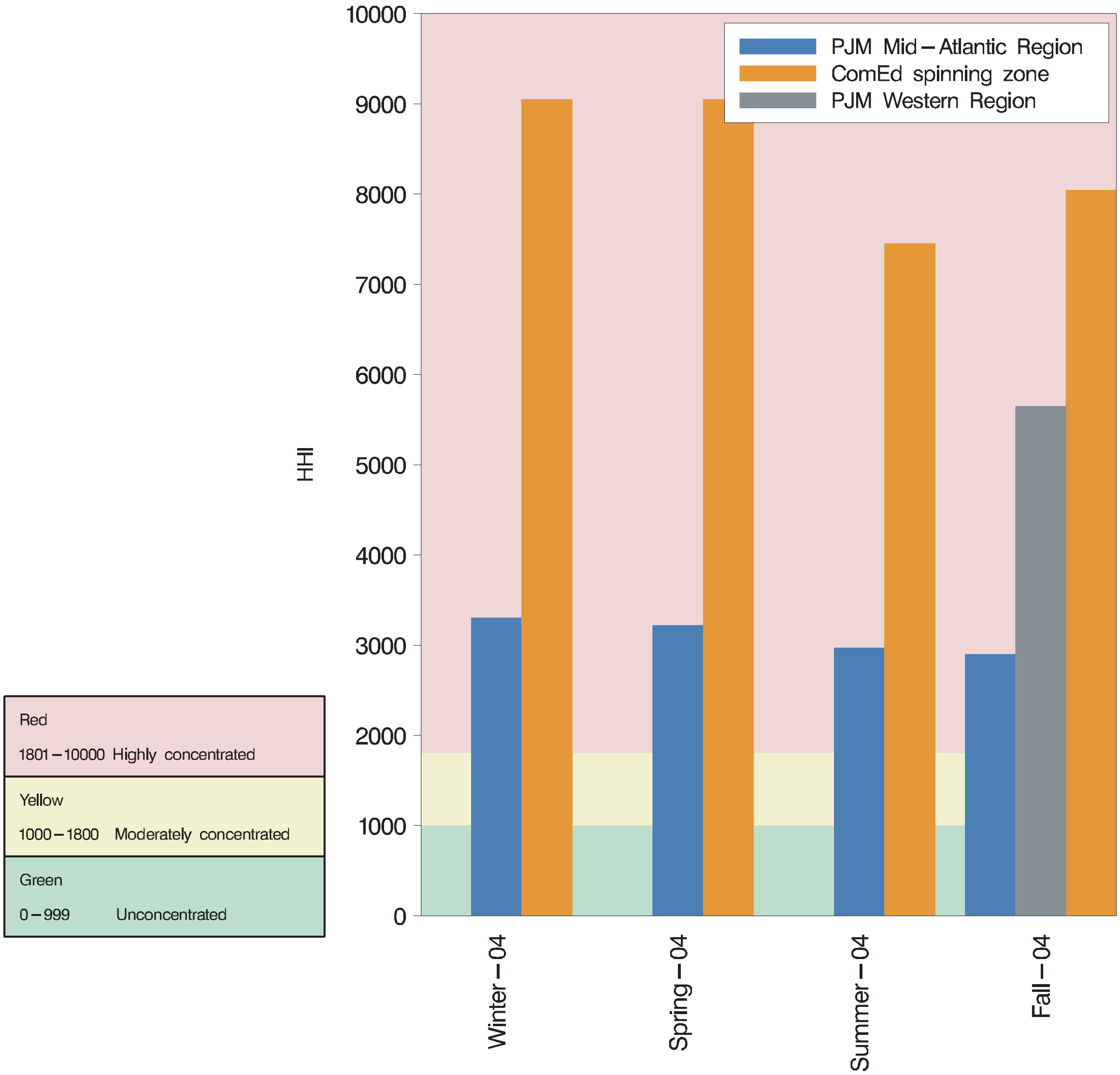
Figure 5-7 - PJM Control Area average hourly Tier 2 spinning MW: Calendar years 2001 to 2004



Market Concentration

Concentration is high in the Tier 2 Spinning Reserve Market in all three geographic markets. (See Figure 5-8.) During calendar year 2004, average HHI for Tier 2 spinning in the Mid-Atlantic Region was 3095 which is highly concentrated. In ComEd, during Phases 2 and 3, the average HHI was 8398. In PJM's AP-AEP-DAY Western Region Spinning Reserve Market during Phase 3 the average HHI was 5648.

Figure 5-8 - PJM system Spinning Reserve Market HHI: Calendar year 2004



Spinning Reserve Market Performance

Spinning Reserve Offers

Figure 5-6 compares average hourly required spinning reserve by month to the average hourly amount of Tier 2 spinning reserve purchased. The average difference was 948 MW.

The PJM spinning requirement is different for each of the three spinning reserve ancillary service territories in the RTO. During calendar year 2004, the monthly average required spinning reserve for the PJM Mid-Atlantic Region varied between 2,300 MW and 863 MW, but averaged approximately 1,100 MW. For the AP Control Zone during Phases 1 and 2, the spinning reserve requirement was between 60 and 124 MW and averaged 99.3 MW. For ComEd during Phase 2, the requirement was always 269 MW. For ComEd in Phase 3, the requirement was 269 MW until December 3, when it was lowered to 216 MW, giving a Phase 3 average of 253 MW. For PJM's AP-AEP-DAY Western Region's Spinning Reserve Market during Phase 3, the hourly spinning reserve requirement was between 242 MW and 494 MW and averaged approximately 370 MW.

Spinning Reserve Prices

Figure 5-9 shows the average price per MW associated with meeting PJM demand for spinning reserve. The average price per MW remained the same in 2004 as it had been in 2003, approximately $15.50 per MWh. There are no price data presented for the Western Region's Spinning Reserve Market because there was almost always adequate Tier 1 spinning reserve to meet the requirements for spinning reserve without clearing the Tier 2 market.

Figure 5-9 - Tier 2 spinning credits per MW: Calendar years 2003 to 2004

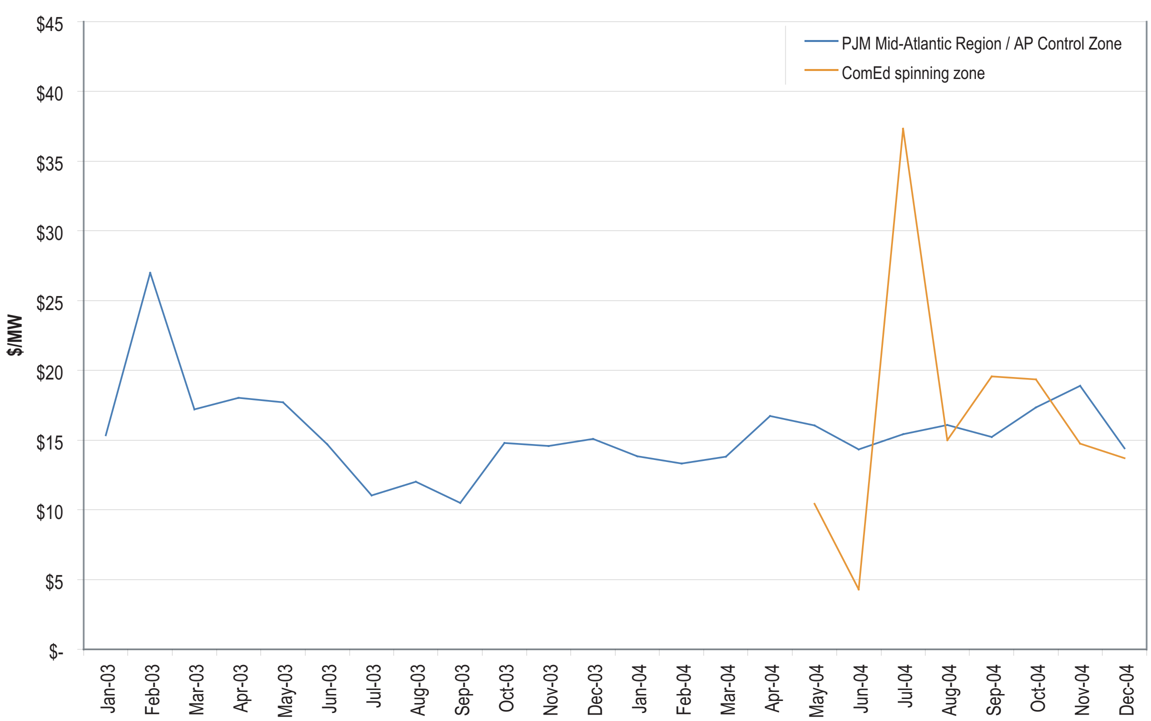


Figure 5-10 displays Tier 2 spinning reserve market-clearing prices (SRMCP) for 2004. Tier 2 spinning reserve prices in the PJM Mid-Atlantic Region were moderate in 2004, averaging $11.01. In ComEd, during Phases 2 and 3, Tier 2 spinning reserve market-clearing prices averaged $15.26. Tier 2 spinning reserve prices spiked in ComEd during July, primarily because of high opportunity costs. As was true in the Regulation Market, these spikes reflected the fact that the marginal units' opportunity costs were relatively high during certain hours because of high energy prices. Offer cost was not a factor in high ComEd SRMCPs. Tier 2 spinning reserve offer prices were capped at $7.50 per MW plus costs and were always less than $10 per MW. The marginal units were needed to meet the spinning requirements for the ComEd spinning zone. The PJM AP-AEP-DAY Western Region's Spinning Reserve Market during Phase 3 almost never had a clearing price because available Tier 1 spinning was always sufficient to cover the spinning requirement. Twice the Tier 2 Spinning Reserve Market was cleared averaging $9.53.

Figure 5-10 - PJM daily average spinning reserve market-clearing prices: Calendar year 2004

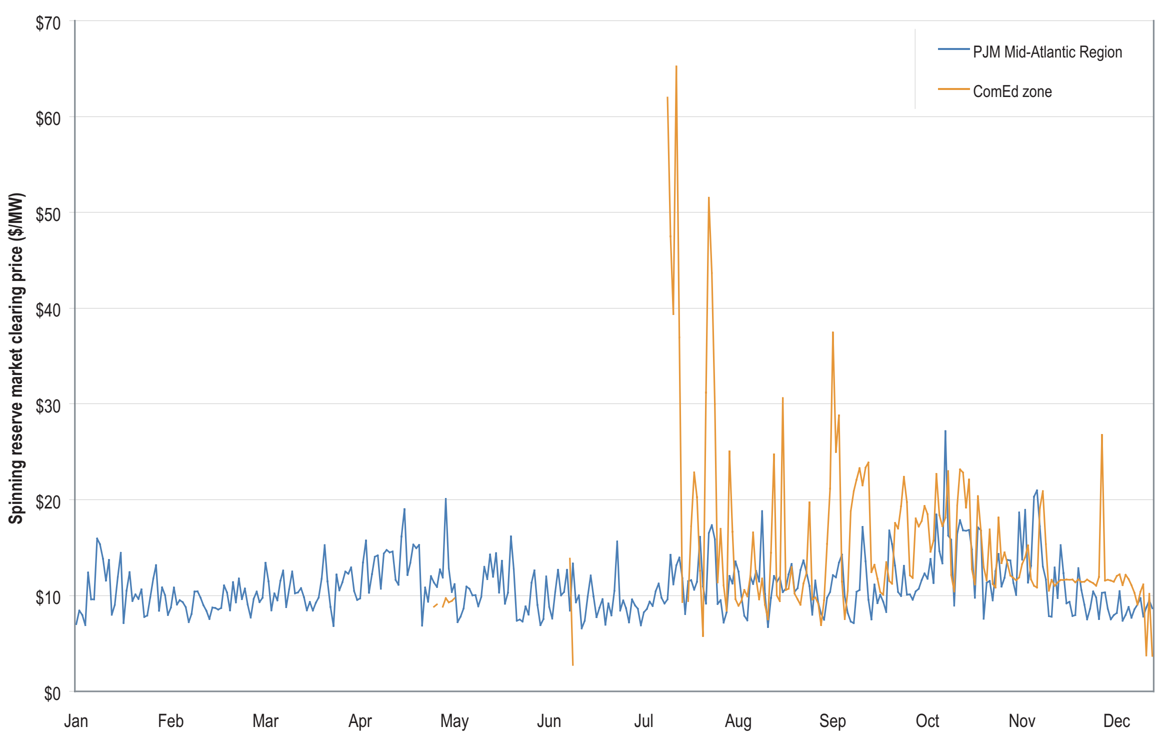


Table 5-7 - Spinning volumes and credits, Tier I and Tier 2: Calendar years 2003 and 2004

	Region	Tier 1 MW	Tier 1 Credits	Tier 2 MW	Tier 2 Credits
2003	PJM Control Area	7,603	$474,490	3,257,908	$50,910,740
2004	ComEd	603	$33,307	390,513	$6,666,075
2004	PJM Mid-Atlantic	5,853	$356,306	3,166,078	$48,487,250
2004	AP-AEP-DAY	626	$34,387	212	$5,125

Table 5-7 shows the level of Tier 1 and Tier 2 spinning reserve purchased from suppliers during calendar years 2003 and 2004. Tier 1 resources are paid only if they respond during spinning events while Tier 2 resources are paid for providing hourly reserve. As a general result, more Tier 2 resources are purchased than Tier 1 resources, and Tier 2 payments are higher than Tier 1 payments. An important exception to this general rule occurred in the PJM AP-AEP-DAY Western Region's Spinning Reserve Market where there is a large baseload of available operating reserves. During October and early November, Tier 1 spinning reserve services were almost always sufficient to cover the spinning requirement so Tier 2 spinning reserve was rarely purchased. During the second week of November, however, when temperatures fell and baseload units were operating higher up their output curves, then an AP-AEP-DAY Western Region Spinning Reserve Market emerged for Tier 2 resources.

Spinning Reserve Availability

A spinning reserve deficit occurs when PJM is not able to assign enough Tier 2 spinning to meet the spinning reserve requirement. Except for two brief periods during the first and third weeks of October when a transmission outage doubled the size of the PJM Mid-Atlantic Region's largest contingency, neither PJM's Mid-Atlantic Region, nor its AP Control Zone, nor its AP-AEP-DAY Western Region, nor its ComEd Spinning Reserve Markets had significant spinning reserve deficits during 2004.

SECTION 6 - CONGESTION

Congestion occurs when available, low-cost energy cannot be delivered to all loads because of limited transmission capabilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units must be dispatched in this constrained area to meet that load.[1] The result is that the price of energy in the constrained area is higher than elsewhere because of the transmission limitations. Locational marginal prices (LMPs) reflect the price of the lowest cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way of pricing energy supply when transmission constraints exist. Congestion reflects this efficient pricing.

As PJM integrated new transmission zones during 2004, the patterns of congestion changed, reflecting additional transmission and generation resources with new cost structures, load requirements and transmission system characteristics.

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1.** The four-month period from January 1 through April 30, 2004, when PJM was comprised of 12 zones.[2] Eleven of these [i.e., 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)] comprised the Mid-Atlantic Region. The remaining zone, the Allegheny Power Company Control Zone (AP), comprised the PJM Western Region.

- **Phase 2.** 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).[3]

- **Phase 3.** 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.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

2 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The 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 the 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.

3 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

- **Total Congestion.** Congestion costs have ranged from 6 to 9 percent of PJM annual total billings since 2000. Congestion costs increased from 7 percent of total billings in calendar year 2003 to 9 percent of total billings in calendar year 2004, a 28 percent increase. Total congestion costs were $808 million in calendar year 2004, a 62 percent increase from $499 million in calendar year 2003. The total PJM billing for 2004 was approximately $8.7 billion, a 26 percent increase over the approximately $6.9 billion billed in 2003.

- **Hedged Congestion.** Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $16 million of the deficiencies for the 17-month planning period that ended May 31, 2004.[4] This means that Financial Transmission Rights (FTRs) were paid at 98 percent of the target allocation level for that period. FTRs through December 31, 2004, of the planning period ending May 31, 2005, have been paid at 97 percent of the target allocation level.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2004, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

- **Zonal Congestion.** To provide an approximate indication of the geographic dispersion of congestion costs, LMP differentials were calculated for control zones in the PJM Mid-Atlantic and Western Regions as they existed at year end. The data show new overall congestion patterns during calendar year 2004.

- **Congested Facilities.** Congestion frequency increased in calendar year 2004 as compared to 2003. During 2004, there were 11,205 congestion-event hours as compared to 9,711 congestion-event hours during 2003. Included in the 2004 total are 2,512 congestion-event hours associated with the Pathway that existed during Phase 2. The Pathway, which was comprised of transmission service reservations through AEP, linked the PJM and the ComEd Control Areas. The management of Pathway constraints through redispatch procedures and reductions in capability limits from transmission loading relief procedures (TLRs) effectively regulated west-to-east flow into PJM. As a result of this limiting behavior, facilities prone to congestion because of west-to-east flow through PJM saw a reduction in loading and thus experienced lower congestion frequency in 2004. This characteristic, combined with a relatively mild summer season, tended to reduce facility loadings in PJM's Mid-Atlantic Region and further contributed to reduced congestion. Excluding Pathway congestion, interfaces, transformers and lines experienced overall decreases in congested hours during 2004 as compared to 2003.

- **Local Congestion.** In calendar year 2004, the PSEG Control Zone experienced 1,784 congestion-event hours, the most of any control zone, but only a 2 percent increase over the 1,751 congestion-event hours the PSEG Control Zone had experienced in 2003. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg

4 PJM accounts for congestion costs and the FTRs and related financial instruments intended to hedge them on a planning period basis. Normally, the planning period will be 12 months long and run from June 1 to May 31 of the following year. For the transition from a calendar to a planning year, the planning period was 17 months long, running from January 1, 2003, until May 31, 2004.

number 1 and number 2 transformers because of a deteriorating condition identified during an inspection. The result was a large increase in congestion-event hours on the Branchburg 500/230 kV transformers. However, a combined decrease of 1,044 congestion-event hours attributable to the Branchburg-Readington 230 kV, Edison-Meadow Road 138 kV and Cedar Grove-Roseland 230 kV facilities, offset the 1,005 hours of congestion on the Branchburg transformers. The Branchburg transformer constraint affected prices across a large geographic area. Prices were increased by this constraint in the PSEG, JCPL and AECO zones, while prices in the remainder of PJM experienced downward pressure as a result of congestion on this facility. The Erie West and North Meshoppen transformers experienced 624 fewer hours of congestion during 2004 and drove the 67 percent reduction in congestion frequency in the PENELEC Control Zone. The DPL Control Zone showed a continued decrease in congestion-event hours of operation, resulting from completion of transmission reinforcements in the southern part of the territory.

- **Post-Contingency Congestion Management Program.** During calendar year 2003, PJM developed, tested and implemented a protocol resulting in less frequent out of merit dispatch than had previously been the case. Under this post-contingency congestion management protocol, a facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start capability or switching to respond to the loss of a facility.

  On August 19, 2004, the United States Federal Energy Regulatory Commission (FERC) accepted PJM's post-contingency congestion management plan.[5] The program was implemented on September 1, 2004, and PJM continues to evaluate candidate facilities for inclusion under this protocol.

Persistent congestion in areas within PJM and the overall level of congestion costs suggest the importance of PJM's continuing efforts to improve the sophistication of its congestion analysis. Congestion analysis is central to implementing the FERC order to develop an approach identifying areas where investments in transmission would relieve congestion where that congestion might enhance generator market power and where such investments are needed to support competition.[6]

In an order dated December 19, 2002, granting PJM full regional transmission organization (RTO) status, the FERC directed PJM to revise its regional transmission expansion planning protocol (RTEPP) to "more fully explain [...] how PJM's planning process will identify expansions that are needed to support competition" and to "provide authority for PJM to require upgrades both to ensure system reliability and to support competition."[7] The FERC approved implementing changes to the PJM Tariff and to its Operating Agreement, expanding PJM's regional transmission planning protocol to include economic planning. The program commenced retroactively with the regional planning cycle that had already begun on August 1, 2003. PJM will, when appropriate, initiate upgrades or expansions of the transmission system to enhance the economic and operational efficiency of wholesale electricity markets in PJM. PJM's economic planning process identifies transmission upgrades needed to address unhedgeable congestion. PJM defines unhedgeable congestion as the cost of congestion attributable to the portion of load affected by a transmission constraint that cannot be supplied by economic generation or hedged with available FTRs.[8] First, market forces are relied upon through the opening of a one-year market window during which

5 108 FERC ¶ 61,196 (2004).
6 96 FERC ¶ 61,061 (2001).
7 101 FERC ¶ 61,345 (2002).
8 104 FERC ¶ 61,124 (2003).

merchant solutions are solicited through the introduction of incentives and the posting of relevant market data. If market forces do not resolve unhedgeable congestion within an appropriate time period, PJM will determine, subject to cost-benefit analysis, transmission solutions that will be implemented through the RTEPP. To date, 54 facilities have experienced sufficient levels of unhedgeable congestion to trigger the opening of a market window to solicit merchant solutions to relieve congestion.

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Markets. Separate accounting settlements are performed for each market. The day-ahead market settlement is based on scheduled hourly quantities and on day-ahead hourly prices. The real-time settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour.

Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by using FTRs which are accounted for on a planning period basis. Real-time congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.

Total congestion charges are the sum of the implicit and explicit day-ahead and balancing congestion charges, plus the day-ahead and balancing congestion charges implicitly paid in the Spot Market, minus any negatively valued FTR target allocations.

- **Implicit Congestion Charges.** These charges are incurred by network service customers in delivering their generation to their load and equal the difference between a participant's load charges and generation credits, less the participant's spot market bill. In the Day-Ahead Energy Market, load charges are calculated as the sum of the demand at every bus times the bus LMP. Demand includes load, decrement bids and sale transactions. Generation credits are similarly calculated as the sum of the supply at every bus times the bus LMP, where supply includes generation, increment bids and purchase transactions. In the Real-Time Energy Market, load charges and generation credits are calculated the same way, using the differences between day-ahead and real-time demand and supply and valuing congestion using real-time LMP.

- **Explicit Congestion Charges.** These charges are incurred by point-to-point service transactions and are equal to the product of the transacted MW and LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Real-Time Energy Market explicit congestion charges are equal to the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time LMP at the transactions' sources and sinks.

- **Spot Market Congestion Charges.** These charges are equal to the difference between total spot market purchase payments and total spot market sales revenues.

Total Calendar Year Congestion

Congestion costs have ranged from 6 to 9 percent of annual total PJM billings since 2000. Congestion costs increased from 7 percent of total billings in calendar year 2003 to 9 percent of total billings in calendar year 2004, a 28 percent increase. Table 6-1 shows total congestion by year from 2000 through 2004. Total congestion costs were $808 million in calendar year 2004, a 62 percent increase from $499 million in calendar year 2003. The increased size of the total PJM Energy Market contributed to the increase in total congestion charges. The total PJM billing for 2004 was approximately $8.7 billion, a 26 percent increase over the approximately $6.9 billion billed in 2003.

The integration of ComEd and then of AEP and DAY contributed to the measured increase in total congestion during 2004. Congestion during the combined Phases 2 and 3 of the year was twice that of the comparable eight-month period in 2003, with 38 percent of this occurring during the five-month, Phase 2 period.

Even though 2004 saw a moderating of congestion frequency on the PJM Western Interface, on the Doubs and Kammer transformers, and on the Cedar Grove-Roseland 230 kV line (Table 6-5), increases in congestion frequency on the Branchburg Transformer, Wylie Ridge transformer and Bedington-Black Oak line (an interface between AP and the PJM Mid-Atlantic Region) offset the effects of these decreases.

Table 6-1 - Total annual PJM congestion [Dollars (millions)]: Calendar years 1999 to 2004

	Congestion Charges	Percent Increase	Total PJM Billing	Percent of PJM Billing
1999	$53	N/A	N/A	N/A
2000	$132	149%	$2,300	6%
2001	$271	105%	$3,400	8%
2002	$430	59%	$4,700	9%
2003	$499	16%	$6,900	7%
2004	$808	62%	$8,700	9%
Total	$2,193	N/A	N/A	N/A

Hedged Congestion

Table 6-2 lists congestion charges, FTR target allocations and credits, payout ratios, and congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. In 2003, however, when the congestion accounting period was changed from a calendar year to a planning period, the accounting period was extended on a one-time basis through May 31, 2004. The transitional period was, therefore, a 17-month period that began on January 1, 2003, and ended on May 31, 2004. PJM is currently in a 12-month planning period that began on June 1, 2004, and will end on May 31, 2005.

Table 6-2 - Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period

		Congestion Charges	FTR Target Allocations	Congestion Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Planning Period 2003 to 2004	Jan-03	$66	$94	$66	70%	$29	$0
	Feb-03	$14	$18	$14	77%	$4	$0
	Mar-03	$52	$42	$42	100%	$0	$10
	Apr-03	$27	$23	$23	100%	$0	$4
	May-03	$27	$41	$27	67%	$14	$0
	Jun-03	$52	$57	$52	90%	$6	$0
	Jul-03	$96	$85	$85	100%	$0	$10
	Aug-03	$59	$53	$53	100%	$0	$6
	Sep-03	$42	$44	$42	95%	$2	$0
	Oct-03	$32	$33	$32	97%	$1	$0
	Nov-03	$18	$17	$17	100%	$0	$1
	Dec-03	$15	$13	$13	100%	$0	$2
	Jan-04	$57	$54	$54	100%	$0	$3
	Feb-04	$22	$16	$16	100%	$0	$6
	Mar-04	$21	$18	$18	100%	$0	$3
	Apr-04	$23	$25	$23	92%	$2	$0
	May-04	$59	$62	$59	95%	$3	$0
	Total	$680	$696	$635	91%	$60	$45
	Values After Excess Congestion Charges Distributed						
		$680	$696	$680	98%	$16	$0
Planning Year 2004 to 2005 (through December 31, 2004)	Jun-04	$64	$67	$64	95%	$3	$0
	Jul-04	$116	$114	$114	100%	$0	$1
	Aug-04	$121	$128	$121	94%	$7	$0
	Sep-04	$47	$47	$47	99%	$0	$0
	Oct-04	$46	$39	$39	100%	$0	$7
	Nov-04	$74	$81	$74	91%	$7	$0
	Dec-04	$160	$150	$150	100%	$0	$9
	Total	$627	$627	$609	97%	$18	$18

Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $16 million of the deficiencies for the 17-month period that ended May 31, 2004. FTRs were paid at 98 percent of the target allocation level during that period. For the first seven months of the planning period ending May 31, 2005 (June 1 through December 31, 2004), FTRs have paid at 97 percent of the target allocation level. This payout ratio may change for the full planning period depending on whether there are net excess revenues at the end of the planning period.

Although aggregate FTRs provided a hedge against 98 percent of the target allocation level during the 17-month period that ended May 31, 2004, all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

Monthly Congestion

Table 6-3 shows monthly congestion charge variations by planning period. During the 17-month period that ended May 31, 2004, monthly congestion charges ranged from a maximum of $96 million in July 2003 to a minimum of $14 million in February 2003. For the balance of 2004, monthly congestion charges ranged from a high of $160 million in December 2004 to a low of $46 million in October 2004.

Table 6-3 - Monthly PJM congestion revenue statistics [Dollars (millions)]: By planning period

	Maximum	Mean	Median	Minimum	Range
2003 to 2004	$96	$40	$32	$14	$82
2004 to 2005*	$160	$90	$74	$46	$114

*The 2004 to 2005 period is presented on a planning period-to-date basis through December 31, 2004.

Approximately 32 percent of all congestion occurring in the 17-month period that ended May 31, 2004, occurred during the summer and winter peak-demand months of July and January.[9] The $686 million in congestion charges during Phases 2 and 3, 2004 were over twice the $340 million during the comparable 2003 period. The increased size of the total PJM Energy Market from the three integrations during Phases 2 and 3 contributed significantly to this increase.

Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions as well as subareas. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones, and subareas consist of portions of one or more zones. At the end of 2004, PJM was comprised of two regions. The PJM Mid-Atlantic Region with 11 control zones and the PJM Western Region with four control zones: the AP, ComEd, AEP and DAY Control Zones.

LMP differentials were calculated for each PJM control zone to provide an approximate indication of the geographic dispersion of congestion costs. LMP differentials for control zones are presented in Figure 6-1 for calendar years 2001 through 2004, and were calculated as the difference between zonal LMP and the Western Hub LMP. The Western Hub was chosen as the unconstrained reference price because it reasonably represents the unconstrained price of energy in the PJM Mid-Atlantic Region.

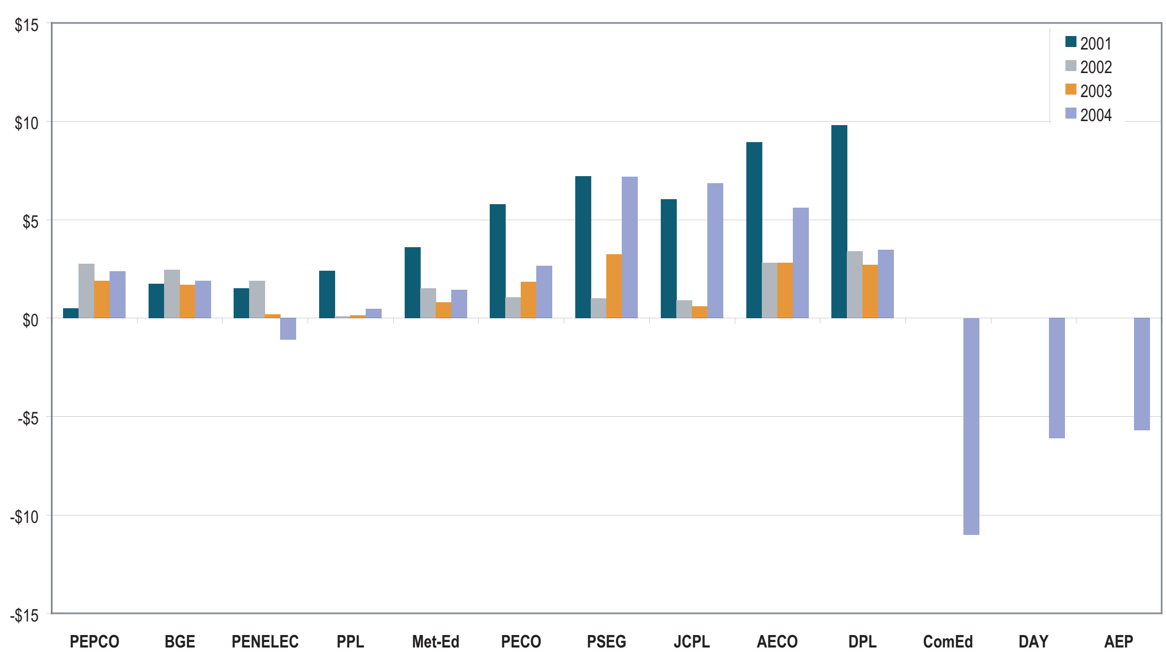
Figure 6-1 shows some new overall congestion patterns in 2004. The historically positive price differential for the PENELEC zone, which was nearly zero in 2003, became slightly negative during

9 The 17-month planning period ended May 31, 2004, included one July summer-peak month and two January winter-peak months.

2004. PENELEC is generally not affected by constraints on major interfaces and its congestion has been predominately local, particularly on the Erie West and the Erie South transformers. The installation of additional transformers at Erie West and Erie South alleviated the area's chronic congestion. Congestion on the Branchburg transformer in the PSEG zone had a downward effect on prices in the PENELEC zone and is responsible for the negative price differential observed relative to the Western Hub in 2004. The Branchburg transformer had a more significant effect on the prices in the PSEG, JCPL and AECO zones. Unlike zones located west of the constraint, the PSEG, JCPL and AECO zones experienced upward pressure on prices resulting from congestion on Branchburg. Further increasing prices in the AECO zone was congestion on AECO zone facilities such as the Cedar interface, Laurel-Woodstown and the Sheildalloy-Vineland line.

The three new zones integrated into PJM during Phases 2 and 3 of 2004 exhibited a negative price differential relative to the Western Hub. Overall, the ComEd Control Zone, during the eight months from its May 1, 2004, integration until the end of the calendar year, exhibited an average differential of approximately $11 per MWh. During Phase 2, Pathway congestion occurred most frequently in a direction from ComEd into the PJM Mid-Atlantic Region, indicating that the price of the marginal resource in PJM was higher than the price in the ComEd Control Area. The resultant price separation tended to make the ComEd Control Area price lower than the price in the PJM Mid-Atlantic Region and consequently at the Western Hub. The AEP and DAY Control Zones, which were integrated during Phase 3, also exhibited lower prices than the PJM Western Hub during the three months of Phase 3. The AEP and DAY Control Zones each exhibited an average differential of approximately $6 per MWh relative to the PJM Western Hub during the final three months of 2004, driven in large part by congestion on the Wylie Ridge transformer.

Figure 6-1 - Annual zonal LMP differences (Reference to Western Hub): Calendar years 2001 to 2004



Congested Facilities

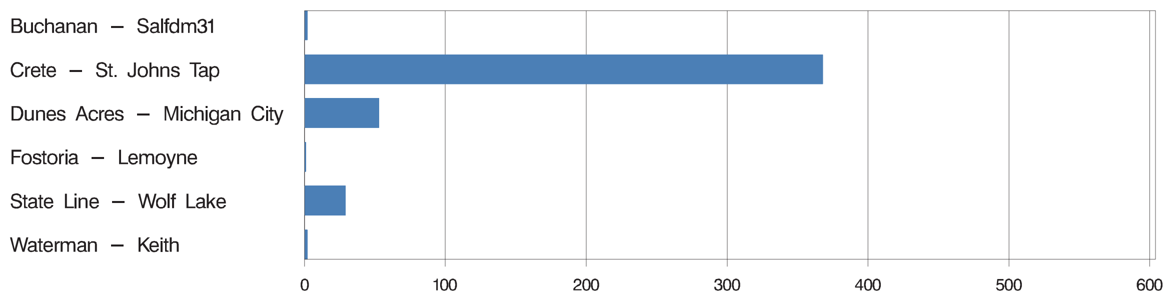
A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. Congestion-event hours refer to the total number of congestion hours for a particular facility. This differs from a constraint hour which refers to any hour during which one or more facilities are congested. Constraints are often simultaneous and, therefore, total congestion-event hours can exceed the number of hours in a year. During calendar year 2004, 185 monitored facilities were constrained, 11 more than had been constrained during 2003. In 2004, there were 11,205 congestion-event hours, a 15 percent increase from 9,711 in 2003. Included in the total for 2004 were 2,512 congestion-event hours associated with the Phase 2 transmission Pathway between PJM and the ComEd Control Area before the integration of the AEP and DAY Control Zones in Phase 3.

The existence of the Pathway during Phase 2 served to reduce congestion on certain PJM facilities. While the throughput capability of the AEP system did not change as a result of the introduction of the Pathway, the congestion management procedures relating to service associated with the Pathway did. Historically, TLR procedures were used to curtail transactions and to address reliability issues. With the incorporation of the Pathway into PJM redispatch procedures, LMP became the mechanism for addressing congestion. Consequently when the Pathway was constrained, PJM would redispatch the system to relieve the limit violation. When the Pathway was constrained from ComEd to PJM, redispatch resulted in the raising of generation in the PJM Control Area relative to that in the ComEd Control Area. Of the Pathway's 2,512 congestion-event hours during 2004, 2,183 hours, or 87 percent, were in the direction from ComEd to PJM. This had the effect of reducing west-to-east flow into the PJM Control Area and raising the prices in the PJM Control Area relative to ComEd. Therefore, as a result of controlling Pathway flow through redispatch, other constraints benefited from the corresponding reduction in flow from the west. Reductions in congestion-event hours associated with the PJM Western and Central Interfaces are examples of constraints which benefited from reduced west-to-east flows during Phase 2. This dynamic also contributed to prices in the PJM Western Region control zones having a lower average value as compared to the PJM Western Hub price. In addition, average temperatures during the summer across the expanded RTO footprint were relatively mild, further reducing loads.

Before Phase 2 integration began, PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) had developed a "Joint Operating Agreement"[10] (JOA) which defines a coordinated methodology for congestion management. This protocol establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by both operators. A flowgate is a single or group of transmission elements intended to model MW flow impact relating to transmission limitations and transmission service usage.[11] PJM models these coordinated flowgates and controls for them in their security-constrained economic dispatch. To date, the most significant of these has been the Crete–St. Johns Tap line located near the southern tip of Lake Michigan. The Crete–St. Johns Tap line accounted for 368 of the 455 congestion-event hours caused by Midwest ISO flowgates during 2004. Midwest ISO flowgates accounted for 4 percent of the total PJM congestion-event hours during 2004. Figure 6-2 shows the number of hours during which PJM took dispatch action to control various Midwest ISO flowgates during calendar year 2004.

10 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM" (March 1, 2004). The agreement is referred to here as the JOA.
11 See NERC Operating Manual, "Flowgate Administration Reference Document," Version 1 (March 21, 2002).

Figure 6-2 - Midwest ISO flowgates impacting PJM dispatch: Calendar year 2004

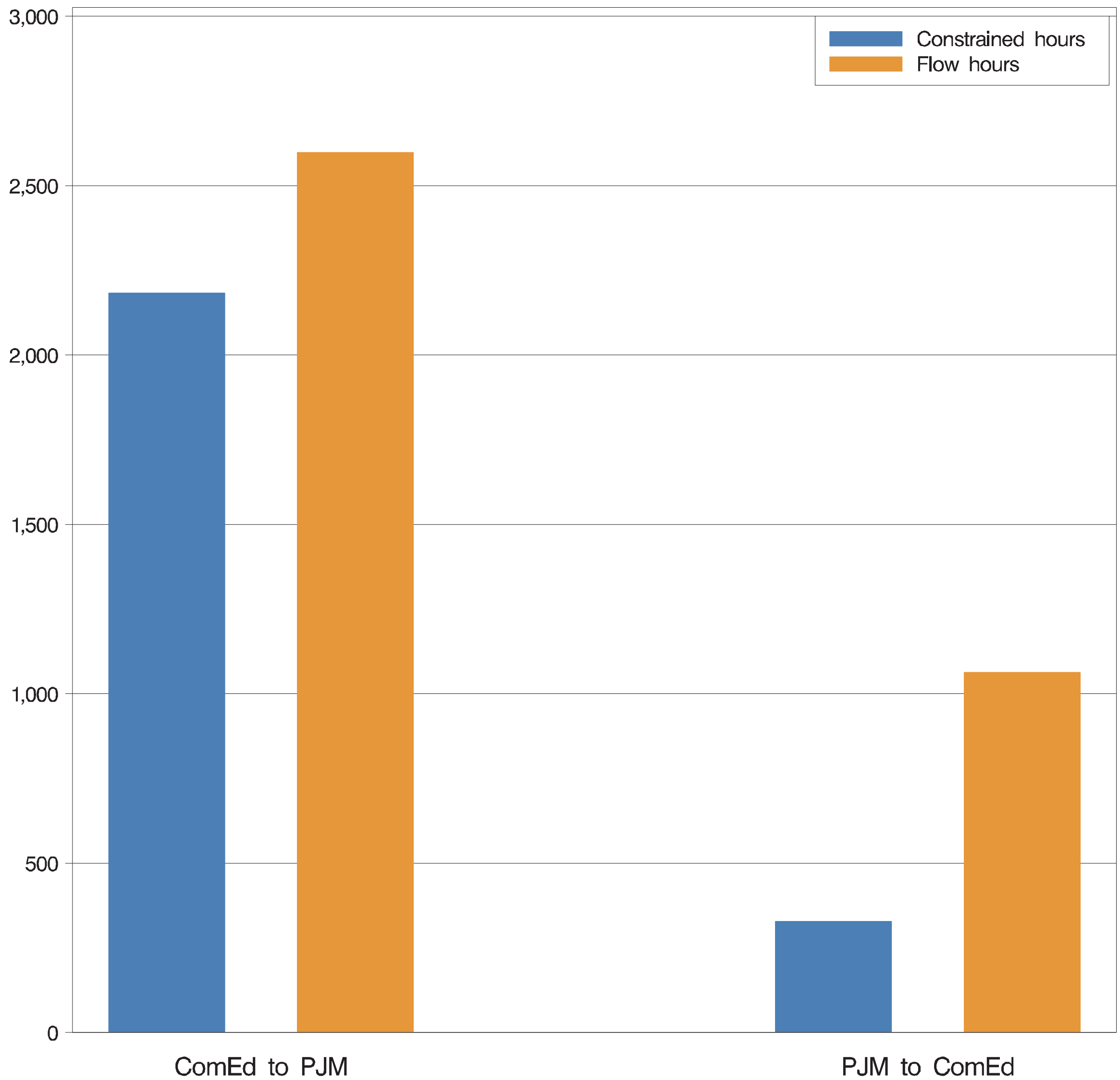


Pathway Congestion during Phase 2

With the integration of the ComEd Control Area on May 1, 2004, PJM instituted a Pathway connecting the PJM Control Area (i.e., the Mid-Atlantic Region and the AP Control Zone) with the ComEd Control Area.[12] This Pathway was an approximately 500-MW, bidirectional, transmission Pathway comprised of transmission service through the AEP Control Zone before its integration into PJM at the beginning of Phase 3.[13] The Pathway's purpose was to facilitate coordinated economic dispatch across its two control areas: the Mid-Atlantic Region plus the AP Control Zone and the new ComEd Control Area. With regard to security-constrained economic dispatch, the Pathway was treated as a closed interface and subject to redispatch procedures to maintain flows within prescribed limits. When Pathway flow was within its limits, the two control areas were dispatched as a single energy market. When Pathway flow was at a directional limit, price separation could occur between the control areas, reflecting a constraint across the Pathway. The Pathway experienced 2,512 hours of congestion during Phase 2, comprising 22 percent of the total PJM congestion-event hours during calendar year 2004. Figure 6-3 shows the directional flow and congestion-event hours for the Pathway.

12 106 FERC ¶ 61,253 (2004).
13 See PJM Internal Audit Department, "Special Investigation ComEd Integration Pathway Issue, Final Report" (June 8, 2004) < http://www.pjm.com/documents/ downloads/ferc/ 2004docs/june/20040625-ferc-pathway-internal-audit-report-redacted.pdf > (121 KB).

Figure 6-3 - Pathway directional flows and hours of congestion: Phase 2, 2004



Pathway flow was predominately into the PJM Control Area reflecting the fact that marginal prices were typically higher in the PJM Control Area than in the ComEd Control Area. When North American Electric Reliability Council (NERC) TLRs were initiated for which Pathway flow had significant impact, the directional limit was adjusted to reduce flow on the constrained facility. Table 6-4 summarizes the number of hours when the Pathway limit was reduced into the ComEd and into the PJM Control Areas.

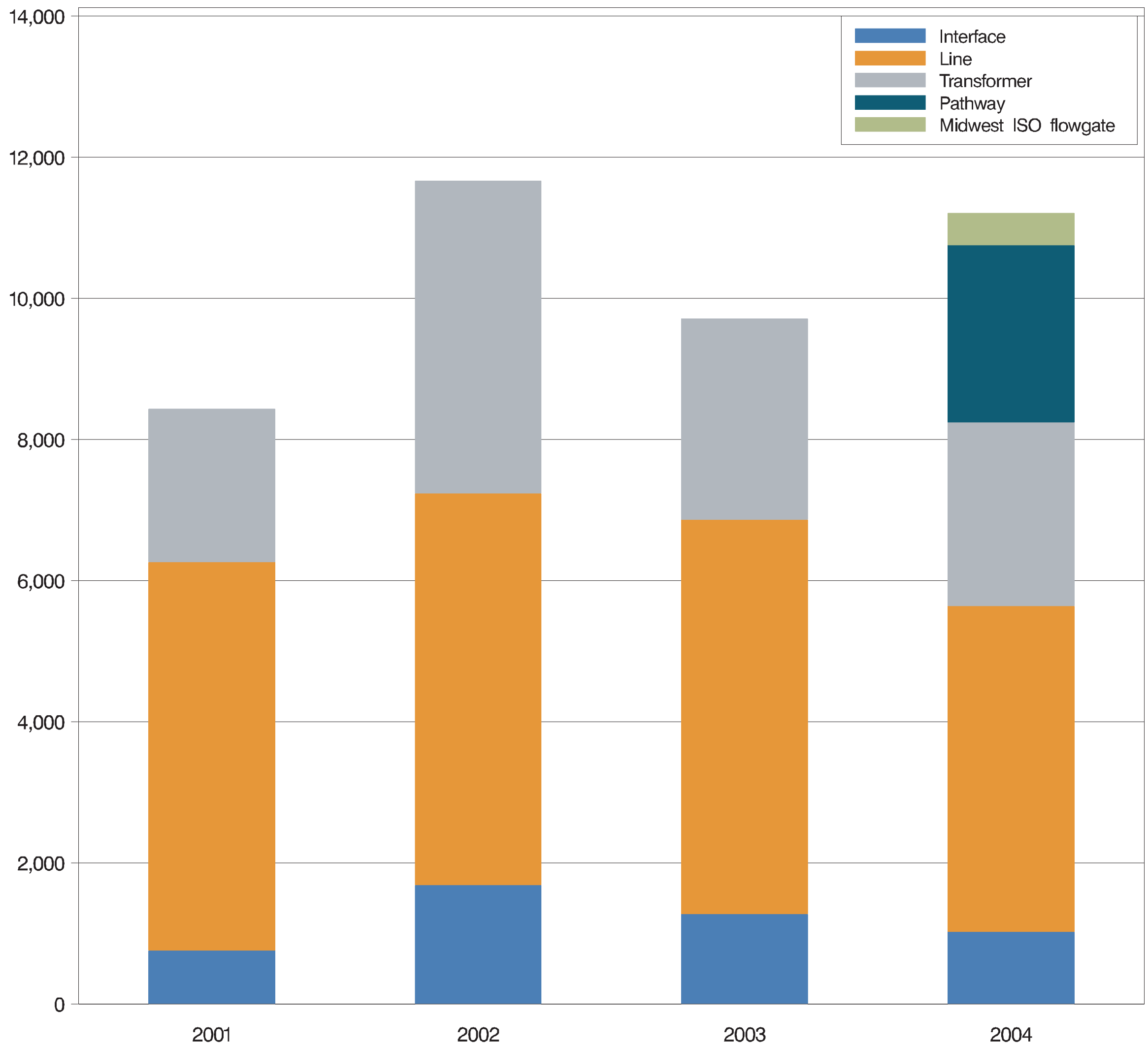
Table 6-4 - Pathway capability limits: Phase 2, 2004

Pathway Capability Limit	ComEd to PJM	PJM to ComEd
0 to 99 MW	203	25
100 to 199 MW	415	119
200 to 299 MW	141	15
300 to 399 MW	138	20
400 to 500 MW	2,775	3,493

Congestion by Facility Type

Figure 6-4 provides congestion-event hour subtotals comparing calendar year results by facility type: line, transformer and interface. Newly included in 2004 is a category for Midwest ISO flowgates for which PJM instituted out of merit order dispatch of generation to control congestion. Midwest ISO flowgates accounted for 455 hours, or 4 percent of total PJM congestion-event hours in 2004. Also included in 2004 is a depiction of congestion associated with the Phase 2 transmission Pathway between the PJM and the ComEd Control Areas. The total number of PJM congestion-event hours increased by about 15 percent to 11,205 hours in 2004 from 9,711 hours in 2003. The 2004 increase in congestion-event hours was attributable to the Pathway and to the Midwest ISO flowgates, which together constituted 26 percent of total PJM congestion-event hours during 2004. Of the Midwest ISO flowgates, the Crete-St. Johns Tap was the most frequently constrained, with 368 hours during 2004. Congestion frequency on transformers, lines and interfaces all showed declines as compared to 2003 levels.

Figure 6-4 - Congestion-event hours by facility type: Calendar years 2001 to 2004



Transformer constraints occurred during 249 fewer hours in calendar year 2004 than in 2003. The largest decreases in congestion occurred on the North Meshoppen, Kammer and Doubs transformers. These three facilities together experienced 882 fewer hours of congestion during 2004 than 2003. Of these, the North Meshoppen transformer had the largest reduction in constrained operation. In sharp contrast to its 442 congestion-event hours during 2003, the North Meshoppen transformer was never constrained during 2004. This improvement was the result of a second transformer and series reactors having been installed at North Meshoppen during 2003. Reduced congestion on the Doubs transformer was the result of a new 500/230 kV transformer installed by Dominion Virginia Power at the Pleasant View station. Conversely, the Branchburg 500 kV transformer located in northern PSEG was constrained for 1,005 hours during 2004 and was the second most frequently constrained facility in PJM during 2004.[14] By comparison, the

14 Bedington – Black Oak was the most frequently constrained facility in PJM during 2004 with 1,131 congestion-event hours.

Branchburg transformers were constrained for 41 hours during 2003. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg number 1 and number 2 transformers as the result of a deteriorating condition identified during an inspection. On May 25, 2004, a special protection scheme (SPS) was installed at Branchburg to reduce congestion impacts of derated facilities. A third transformer is scheduled to be installed at Branchburg by June 30, 2005, to relieve this constraint. The number 1 and number 2 transformers at Branchburg are scheduled to be replaced by June 2007.

Interface constraints occurred during 256 fewer hours in 2004 than in 2003. Interfaces are typically defined by a cross section of transmission paths and are used to represent the flow into or through a wider geographic area. The largest improvements were on the PJM west 500[15] and PJM Western Interfaces. Combined, these two interfaces accounted for a 305-hour decline in congestion-event hours during 2004. The PJM Eastern Interface experienced 221 congestion-event hours in 2004 as compared to 203 hours during 2003. During December 2004, the PJM Eastern Interface experienced 160 hours, or 72 percent of its annual total congestion-event hours because of generation outages at the Salem and Hope Creek stations. Of all the interfaces, the Cedar interface in the AECO Control Zone experienced the largest increase in congestion versus 2003. The 605 hours of congestion on this interface constituted a 53 percent increase over 2003, and triggered the opening of a market window under the PJM economic planning process for new or upgraded transmission facilities.[16] The Cedar interface accounted for 5 percent of total PJM congestion-event hours during 2004.

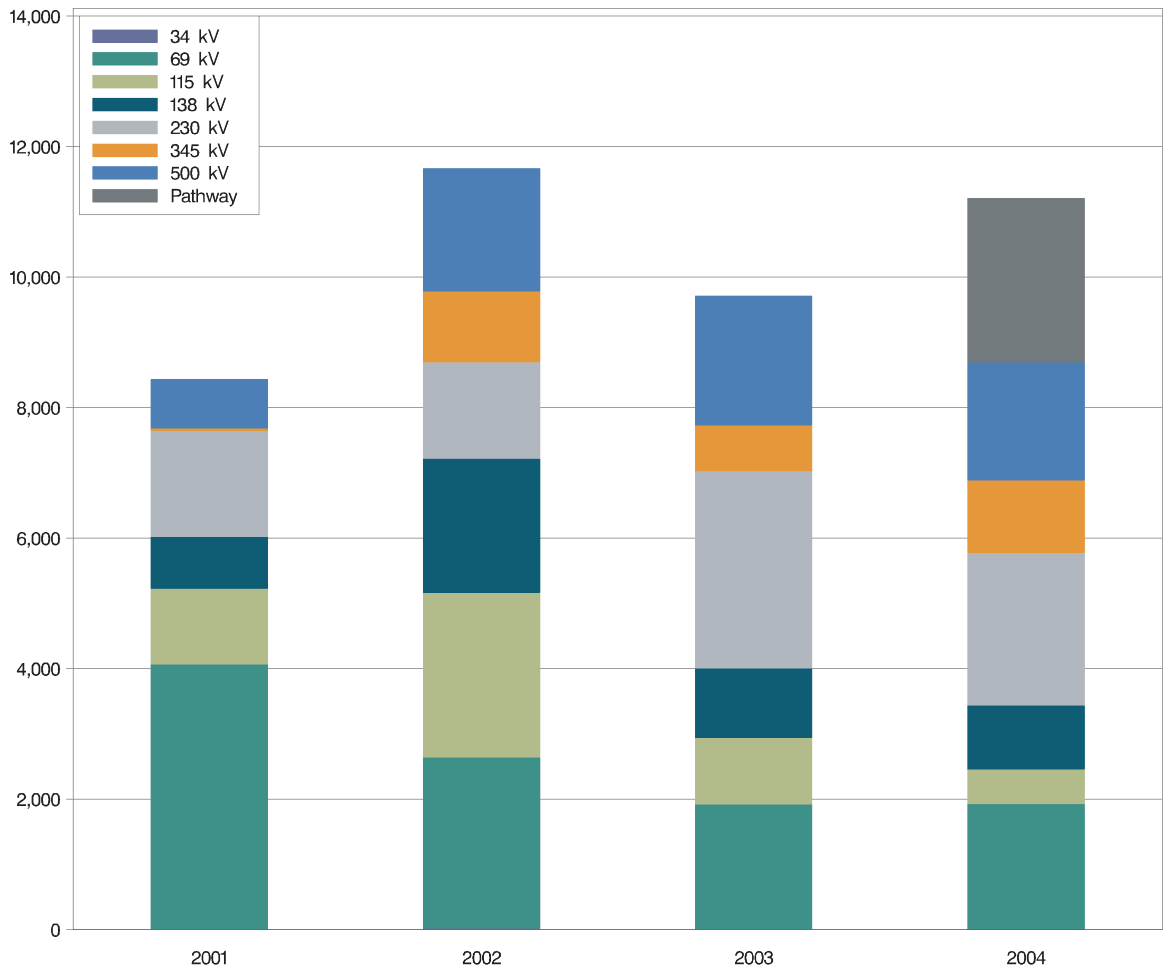
Thermal transmission line limits accounted for 41 percent of all congestion-event hours experienced in 2004. The 4,622 hours of transmission line congestion in 2004 constituted a 968-hour decrease from 2003 levels. Cedar Grove-Roseland had the largest reduction in congestion with 150 hours as compared to the 719 hours experienced during 2003. Also significantly reduced were the Hummelstown-Middletown Junction 230 kV, Branchburg-Readington 230 kV, Edison-Meadow Road 138 kV and Laurel-Woodstown 69 kV lines which together experienced 907 fewer congestion-event hours than they had in 2003. The Shieldalloy-Vineland 69 kV line located in southern New Jersey had the largest increase in congestion with 444 hours during 2004, nearly five times the 2003 level. The Bedington-Black Oak line with 1,131 congestion-event hours was the single most constrained facility in PJM during 2004. Both the Shieldalloy-Vineland and Bedington-Black Oak 500 kV lines were among 54 facilities which experienced enough unhedgeable congestion during 2004 to trigger the opening of a market window under the PJM economic planning process.

Figure 6-5 depicts congestion-event hour subtotals by facility voltage class. Congestion on the Phase 2 transmission Pathway between the PJM and the ComEd Control Areas is depicted as a separate item. Congestion-event hours on 230 kV class facilities were down 676 hours from 2003, with the largest reduction in this class coming from the Cedar Grove-Roseland 230 kV line in PSEG. Contributing to this 569-hour decrease in congestion was the presence of the Branchburg transformer constraint, which limited the flow of power into the northern PSEG area, effectively reducing the occurrence of the Cedar Grove-Roseland 230 kV constraint. There were 484 fewer congestion-event hours on 115 kV facilities in 2004 as compared to 2003. The largest reduction in congestion among 115 kV class facilities was the North Meshoppen transformer in PENELEC. During 2003, a second transformer was installed at North Meshoppen along with series reactors

15 The PJM west 500 interface constraint is used in response to simultaneous post-contingency voltage problems caused by high transfers across the western, central and/or eastern PJM Mid-Atlantic system, and the southern portion of the PJM Mid-Atlantic system.
16 See Appendix H, "Glossary," for definitions of the voltage threshold levels relevant to triggering economic planning activity.

resulting in a 442-hour reduction in congestion in 2004 as compared to 2003. Congestion on 500 kV class facilities occurred for 176 fewer hours as compared to 2003. The Kammer transformer, PJM west and PJM west 500 kV interfaces together contributed 525 hours toward this reduction. Congestion on 345 kV class facilities increased by 410 hours as compared to 2003. This increase was driven by congestion on the Wylie Ridge transformer which was constrained 642 hours during 2004 as compared to 537 hours during 2003.

Figure 6-5 - Congestion-event hours by facility voltage: Calendar years 2001 to 2004



Constraint Duration

Table 6-5 lists calendar year 2003 and 2004 constraints that affected more than 10 percent of PJM load or that were most frequently in effect and shows changes in congestion-event hours between the years.[17]

17 Constrained-hour data presented here use the convention that if congestion occurs for 20 minutes or more in an hour, the hour is congested.

Constraints 1 through 8 are the primary operating interfaces. For this group, the number of congestion-event hours decreased from 2,376 to 2,235 hours between 2003 and 2004, a 6 percent drop. The AP Control Zone facilities, items number 1, 2, 7 and 8, were constrained 1,870 hours in 2004, an 11 percent increase in frequency compared to 2003. This increase was driven by increased congestion frequency on the Bedington-Black Oak line and the Wylie Ridge transformer. The PJM Mid-Atlantic Region facilities, items number 3 to 6, were constrained 365 hours, a 47 percent decrease versus 2003.

Table 6-5 - Congestion-event summary: Calendar years 2003 to 2004

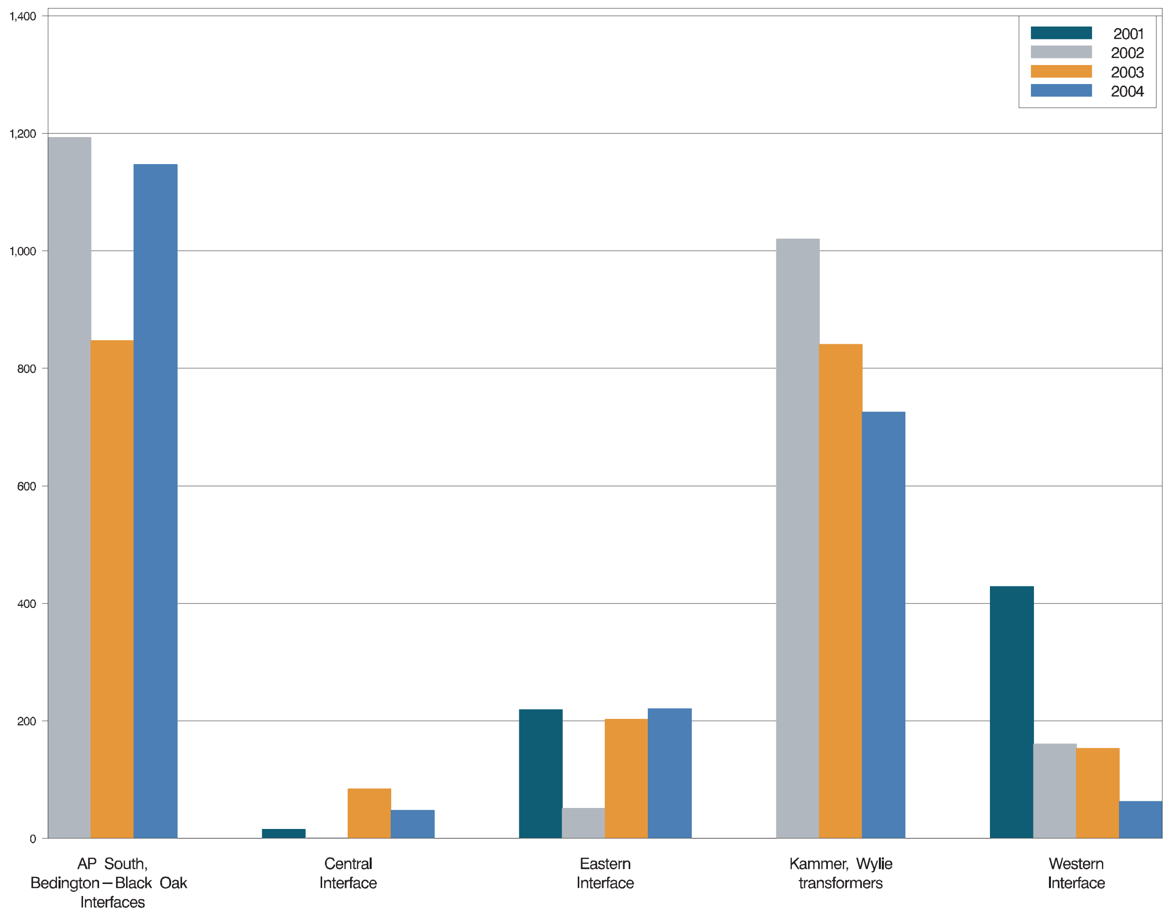
No.	Constraint	Congestion-Event Hours			Percent of Annual Hours		
		2003	2004	Change	2003	2004	Change
1	Kammer Transformer	304	84	-220	3%	1%	-3%
2	Wylie Ridge Transformer	537	642	105	6%	7%	1%
3	Western Interface	153	63	-90	2%	1%	-1%
4	PJM West 500	248	33	-215	3%	0%	-2%
5	Central Interface	84	48	-36	1%	1%	-0%
6	Eastern Interface	203	221	18	2%	3%	0%
7	AP South Interface	32	13	-19	0%	0%	-0%
8	Bedington - Black Oak	815	1,131	316	9%	13%	4%
9	Doubs Transformer	305	85	-220	3%	1%	-3%
10	Branchburg - Readington	242	108	-134	3%	1%	-2%
11	Cedar Grove - Roseland	719	150	-569	8%	2%	-7%
12	Branchburg Transformer	41	1,005	964	0%	11%	11%
13	Shieldalloy-Vineland	89	444	355	1%	5%	4%
14	Keeney AT5N Transformer	194	102	-92	2%	1%	-1%
15	Crete - St. Johns Tap	N/A	368	N/A	N/A	4%	N/A
16	Cedar Interface	396	605	209	5%	7%	2%
17	Lewis-Motts - Cedar	245	128	-117	3%	1%	-1%
18	Laurel - Woodstown	597	401	-196	7%	5%	-2%
19	Jackson Transformer	45	231	186	1%	3%	2%
20	Wye Mills AT2 Transformer	7	128	121	0%	1%	1%
21	North Meshoppen Transformer	442	0	-442	5%	0%	-5%
22	Kanawah-Matt Funk	N/A	51	N/A	N/A	1%	N/A
23	Cloverdale-Lexington	N/A	31	N/A	N/A	0%	N/A

During 2004, constraint frequency on the main operating interfaces affecting large amounts of PJM load was reduced considerably.

Congestion-Event Hours by Facility

Constraints that affected regions during calendar years 2001 through 2004 are presented in Figure 6-6. The Bedington-Black Oak line and the Wylie transformers were the most significant regional constraints, and together comprised 16 percent of total PJM congestion-event hours. Congestion on the Bedington-Black Oak line and on the Wylie transformers increased by 316 hours and 105 hours, respectively, versus 2003 levels. The Kammer transformer and the PJM Western Interface were constrained considerably less often than in 2003, down 72 percent and 59 percent, respectively. The ability to dispatch resources to the west of these constraints resulting from the integration of the ComEd, AEP and DAY Control Zones provided better control and reduced the occurrence of congestion.

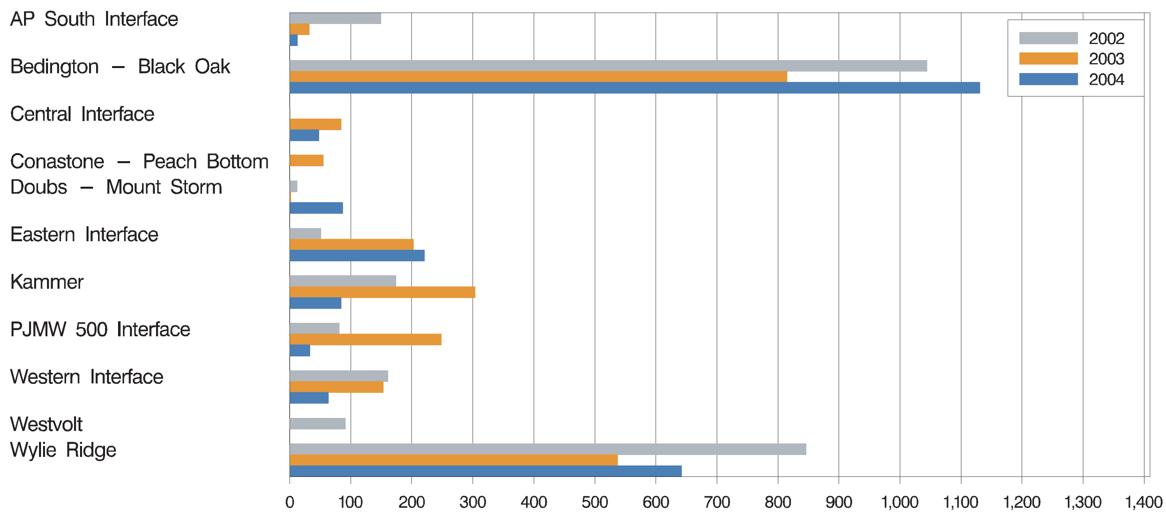
Figure 6-6 - Regional constraints and congestion-event hours by facility: Calendar years 2001 to 2004



Congestion-Event Hours for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Figure 6-7 shows the occurrences of 500 kV constraints. The Wylie Ridge 500/345, Kammer 765/500, Bedington-Black Oak and the AP south interfaces were constrained a combined total of 1,870 congestion-event hours in 2004 as compared to 1,688 hours in 2003, an increase of 182 hours or about 11 percent. In the PJM Mid-Atlantic Region, the Western, Central and Eastern Interfaces were constrained a total of 332 hours, a 52 percent reduction over the 688 hours experienced during 2003.

Figure 6-7 - 500 kV zone congestion-event hours by facility: Calendar years 2002 to 2004



Congestion-Event Hours for the Bedington-Black Oak and AP South Interfaces

The AP extra-high-voltage (EHV) system is the primary conduit for energy transfers from the AP and midwestern generating resources to southwestern PJM and eastern Virginia load, and, to a lesser extent, to central and eastern PJM. Two AP reactive interface constraints, Bedington-Black Oak and AP south, often restrict west-to-east energy transfers across the AP EHV system. During Phase 3, Bedington-Black Oak and AP south were constrained 341 hours and 12 hours, respectively. During this same period in 2003, Bedington-Black Oak and AP south were constrained 78 hours and 15 hours, respectively. By comparison during Phases 1 and 2 combined, Bedington-Black Oak and AP south were constrained 790 hours and one hour, respectively. With 1,131 congestion-event hours, Bedington-Black Oak was the most frequently constrained facility in PJM during calendar year 2004. Bedington-Black Oak experienced sufficient unhedgeable congestion during 2004 to trigger the opening of a market window under the PJM economic planning process. The PJM Market Monitoring Unit concluded that the AP Control Zone's south interface constraint was competitive enough to be exempted from offer-capping procedures and recommended this modification in an August 26, 2004, filing to the FERC.[18] Prior to the integration of the AP Control Zone into PJM on April 1, 2002, the primary controlling action for these constraints had been for AP to restrict energy transfers through its system, including transfers from western resources to PJM and Dominion Virginia Power (VAP). This action had the effect of raising the overall PJM dispatch rate higher than it would have been if the transactions had not been curtailed. The result was increased energy prices for the entire PJM Mid-Atlantic Region, regardless of location. There was no impact on measured congestion because the entire PJM system was affected.

After the AP Control Zone was integrated into the PJM market and the redispatch of PJM generation was used to control AP transmission facilities, a significant change in price impacts occurred. Rather than simply restricting relatively low-cost energy transfers, higher cost generating units

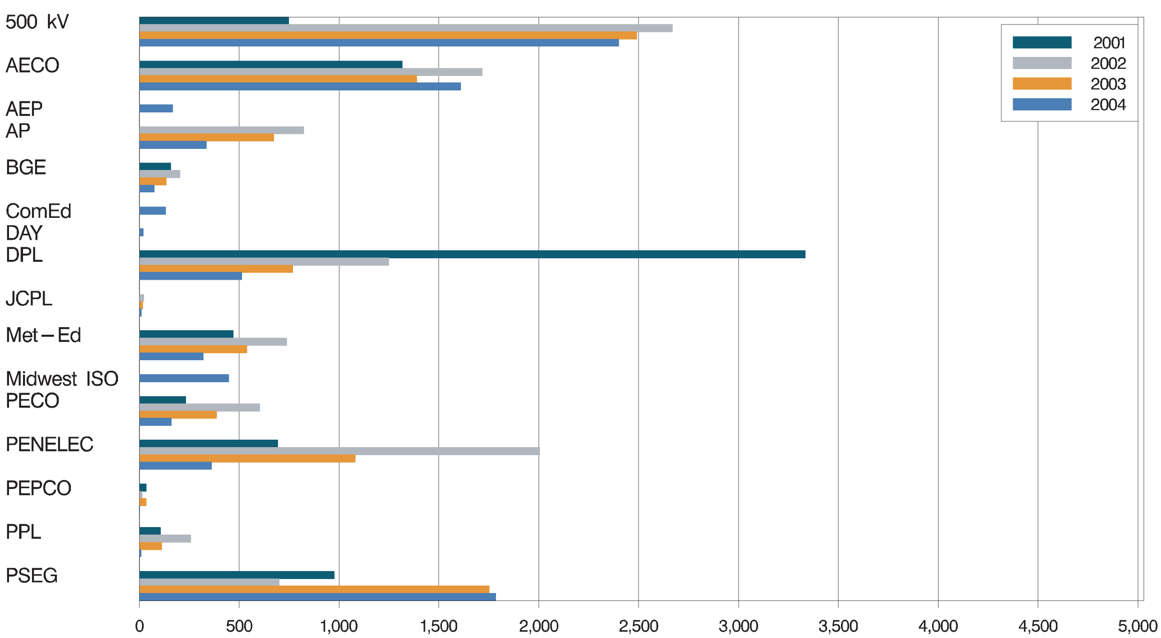
18 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket Nos. ER04-539-001, 002 and ER04-121-000 (October26, 2004), Report of the PJM Market Monitor, paragraph 17.

were dispatched out of merit order (redispatched) in order to serve load in the transmission-constrained areas. As a result, the price of energy in the constrained areas was higher than elsewhere and congestion occurred. Higher LMPs resulted only at those locations directly limited by a constrained facility while lower LMPs occurred elsewhere. The PEPCO Control Zone was the most directly affected by these constrained facilities, followed by the BGE Control Zone.

Local Congestion

Constraints within specific zones from calendar years 2001 through 2004 are presented in Figure 6-8 which compares the frequency of constraints that occurred in each zone and on the 500 kV system. In 2004, the PSEG Control Zone had 1,784 congestion-event hours, a 2 percent increase versus 2003. Significant decreases in constrained operation on the PSEG system attributable to the Branchburg-Readington 230 kV, Edison-Meadow Road 138 kV and Cedar Grove-Roseland 230 kV facilities offset the 1,005 hours of congestion on the Branchburg transformers. The Erie West and North Meshoppen transformers experienced 624 fewer hours of congestion during 2004 and drove the 67 percent reduction in congestion in the PENELEC Control Zone. Congestion-event hours in the AECO Control Zone increased by 221 hours, or 16 percent, in 2004 versus 2003. This was driven by increased congestion frequency on the Shieldalloy-Vineland line and the Cedar interface, which combined experienced 1,049 hours of congestion during 2004.

Figure 6-8 - Congestion-event hours by zone: Calendar years 2001 to 2004



Zonal and Subarea Congestion-Event Hours and Congestion Components

Figure 6-9 through Figure 6-36 present constraints by control zones and subareas, and demonstrate the influence of individual constraints on zonal prices during calendar year 2004. Constraints can have wide-ranging effects, influencing prices across multiple zones. To illustrate this, the figures depict the congestion component of each zone's annual average LMP. The effects of each constraint during calendar year 2004 are expressed as a percent of the control zone's annual average LMP. The top 10 constraints affecting zonal LMP are depicted in the congestion component graphs.

Figure 6-9 illustrates AECO Control Zone constraints. In particular, the very small Cedar subarea, consisting of just two 69 kV substations, Motts Farm and Cedar, continued to be frequently constrained and accumulated enough unhedgeable congestion to trigger the opening of a market window under the PJM economic planning process. Cedar subarea congestion comprised 7 percent of all PJM congestion-event hours during 2004. Also significant was the Laurel-Woodstown 69 kV line in southern New Jersey (SNJ), which comprised 25 percent of the total congestion-event hours in the AECO Control Zone during 2004. The Shieldalloy-Vineland 69 kV line, also located in SNJ, experienced 444 hours of congestion during 2004, or 28 percent of the total hours for the AECO zone. Both the Laurel-Woodstown and Shieldalloy-Vineland 69 kV lines triggered the opening of a market window through the PJM economic planning process during 2004.

Figure 6-9 - AECO Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

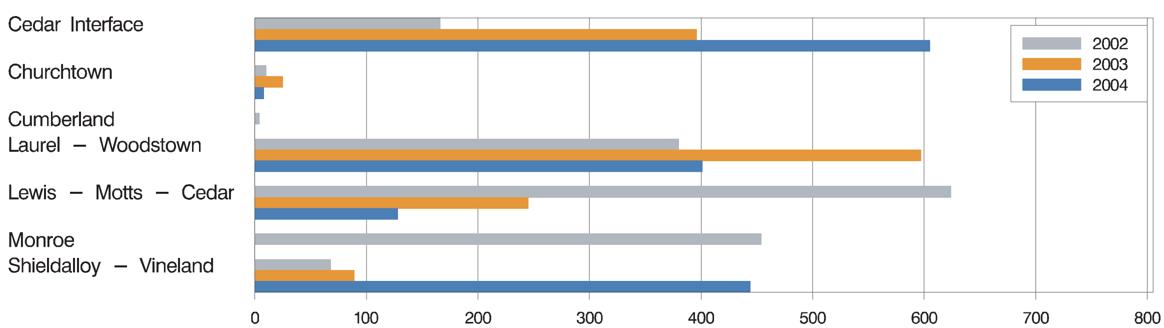


Figure 6-10 depicts the congestion components of AECO zone LMP. The Bedington-Black Oak and Shieldalloy-Vineland constraints caused the greatest increase in prices within the AECO zone. The Cedar Grove-Roseland constraint caused the greatest decrease in prices in the AECO zone.

Figure 6-10 - AECO Control Zone congestion components: Calendar year 2004

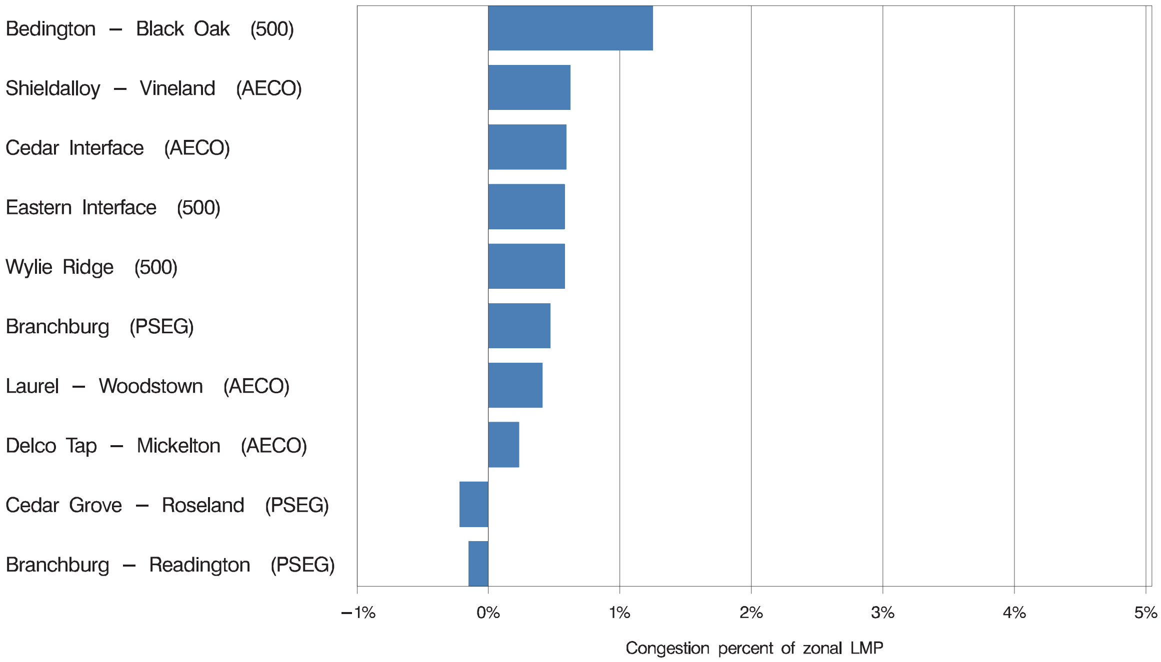


Figure 6-11 illustrates the AP Control Zone constraints. Congestion-event hours in the AP zone were reduced considerably from 2003 levels, down a total of 266 hours or 21 percent. Driving this improvement was a reduction in congestion on the Doubs 500/230 kV transformer which experienced 220 fewer congestion-event hours during 2004 than it had in 2003. This reduction is attributable in part to the installation by Virginia Power of a new 500/230 kV transformer at the Pleasant View station.

Figure 6-11 - AP Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

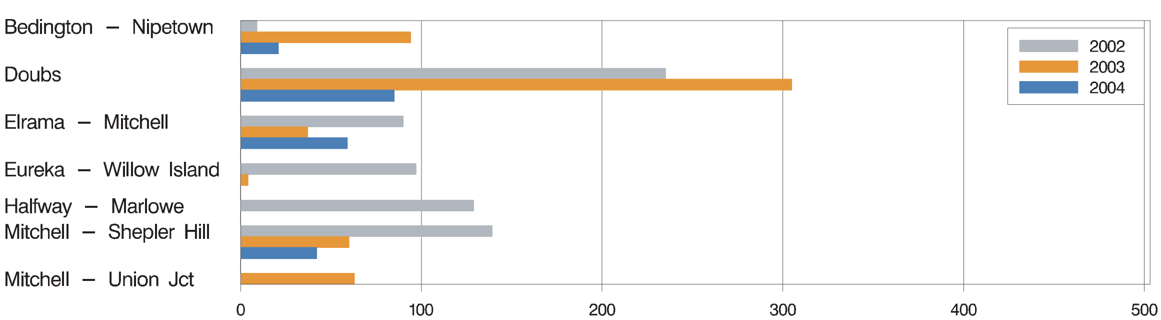


Figure 6-12 depicts the congestion components of the AP Control Zone LMP. The Bedington-Black Oak constraint caused the greatest increase in prices while the Branchburg transformer constraint in PSEG caused the greatest decrease in prices in the AP zone.

Figure 6-12 - AP Control Zone congestion components: Calendar year 2004

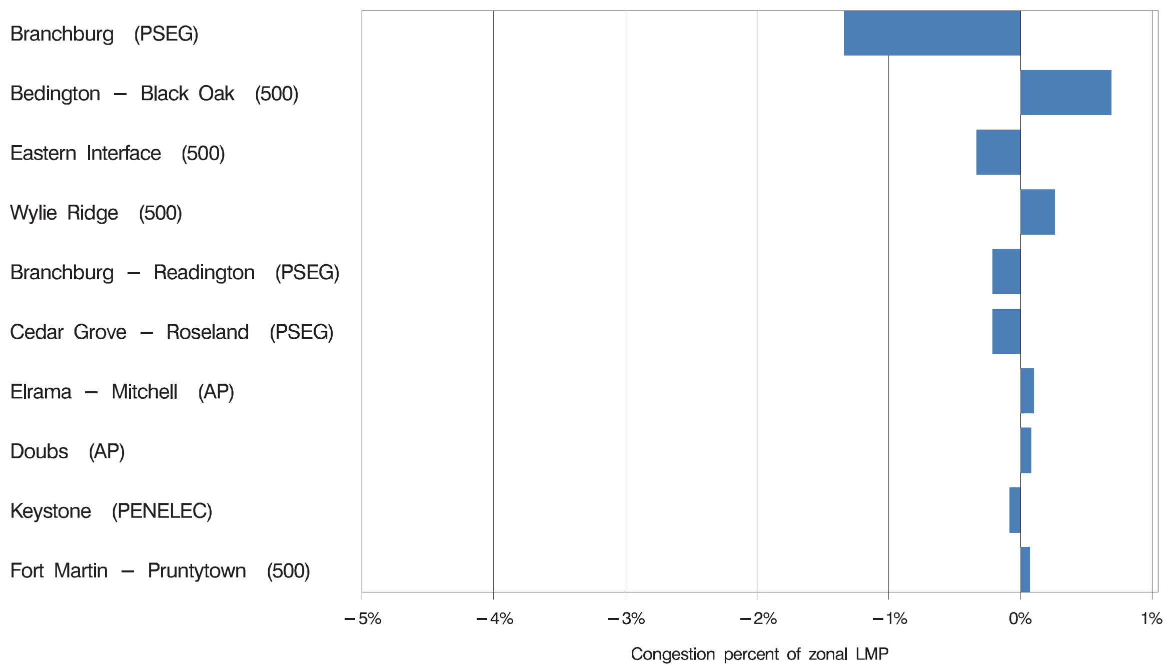


Figure 6-13 illustrates the BGE Control Zone constraints. With 74 congestion-event hours, the BGE Control Zone comprised less than 1 percent of the total PJM congestion-event hours in 2004. One facility, the Brandon Shores-Riverside 230 kV line, had been significantly constrained during 2003, but experienced only 25 hours of congestion during 2004.

Figure 6-13 - BGE Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

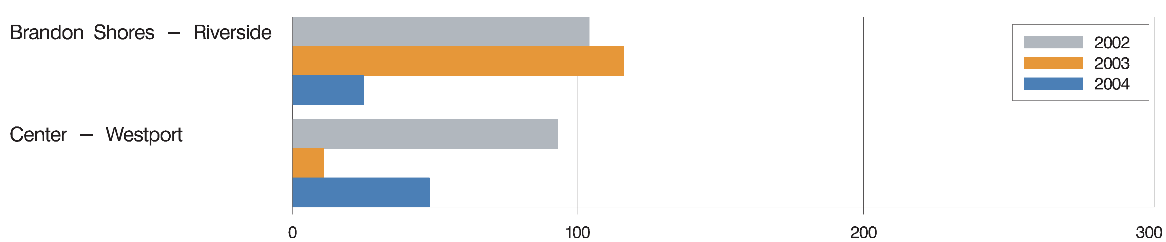


Figure 6-14 depicts the congestion components of the BGE Control Zone LMP. The Bedington-Black Oak constraint caused the greatest increase in prices while the Branchburg transformer constraint in PSEG caused the greatest decrease in prices in the BGE zone.

Figure 6-14 - BGE Control Zone congestion components: Calendar year 2004

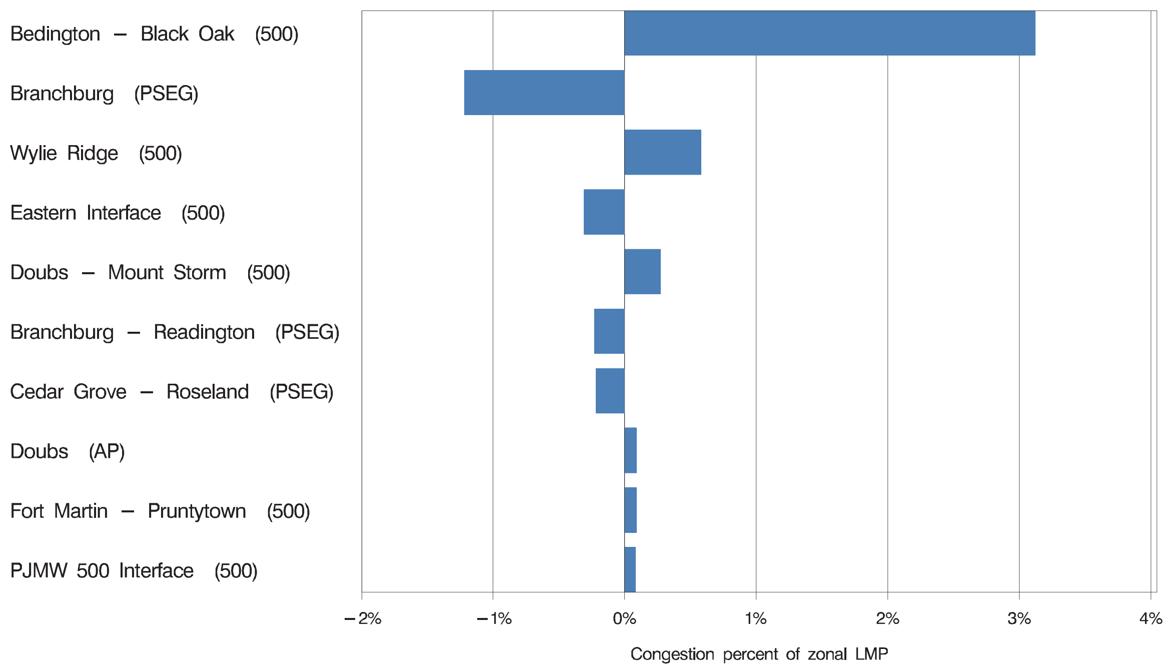


Figure 6-15 depicts DPL Control Zone constraint occurrences. It shows that the southern portion of the Delmarva Peninsula (DPLS) has experienced numerous constraints over the past three years, but their frequency has declined steadily. This continuing improvement in performance is attributable to investments in transmission improvements and reinforcements during the last four years. During 2004, congestion-event hours in the DPL zone fell 33 percent from 2003 levels. DPL zone congestion-event hours represented 5 percent of total congestion-event hours in PJM. While improvements were widespread, the largest contributions came from reductions at the Keeney AT5N transformer and the Cheswold 138/69 kV transformer. Improvements at Keeney are the result of disconnect upgrades at Keeney. These upgrades were performed on the AT-50 and AT-51 transformers and were completed in March and April 2004 respectively. Improvements at Cheswold are the result of the replacement of the Cheswold 138/69 kV transformer in May 2003. As a result, this facility experienced no congestion during 2004 versus the 77 hours experienced in 2003 and the 263 hours during 2002. Although constraints in DPLS have historically been much more frequent than those in the northern subarea of DPL (DPLN) and in the southeast PJM (SEPJM) subarea, the difference in congestion-event hours has decreased significantly.

Figure 6-15 - DPL Control Zone congestion-event hours by subarea: Calendar years 2001 to 2004

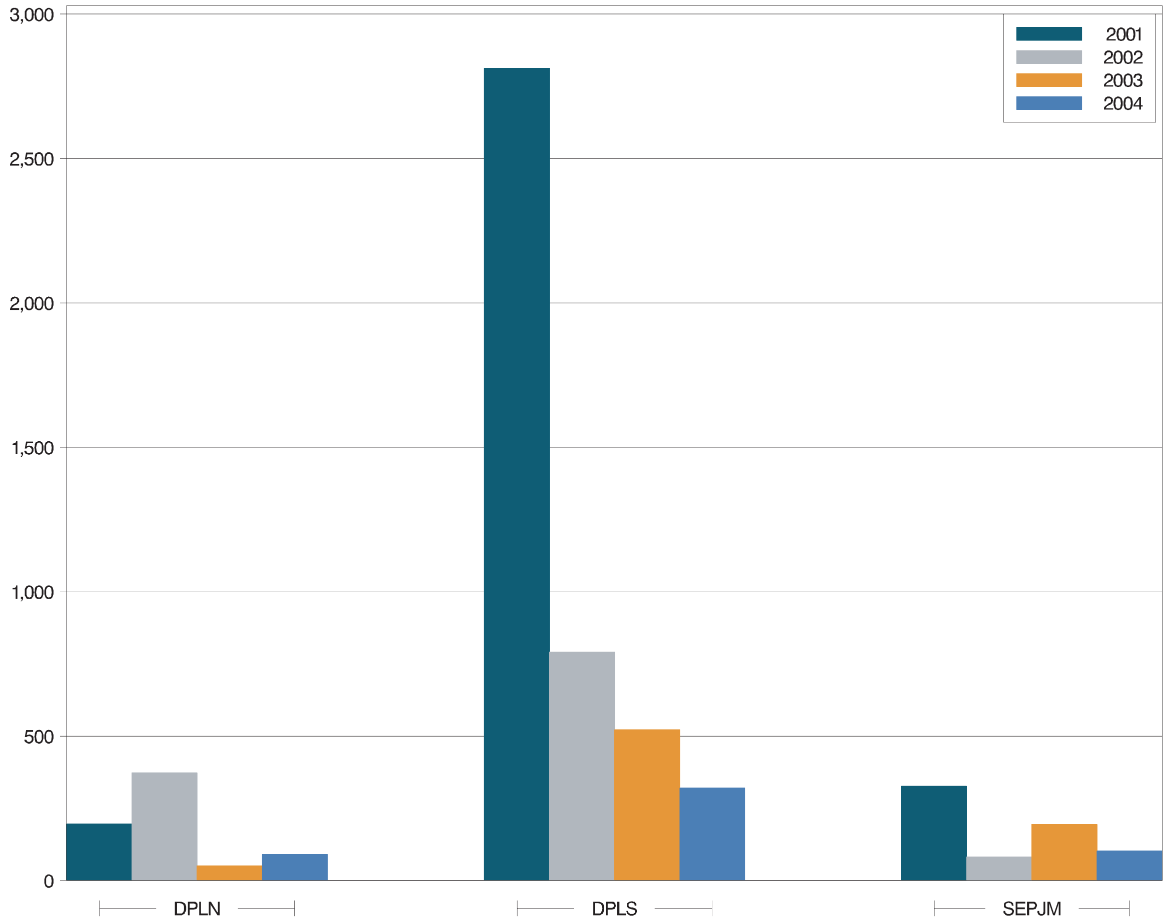


Figure 6-16 illustrates DPLS congestion-event hours by facility. The largest improvement was a 77-hour reduction on the Cheswold transformer in calendar year 2004 as compared to 2003. The reduction on Cheswold is largely attributable to the upgrade of the Cheswold 138/69 kV transformer in May 2003. Only one facility in DPLS was constrained more than 100 hours during 2004. The Wye Mills AT2 69 kV transformer was constrained 128 hours and was the most constrained facility in the DPL Control Zone.

Figure 6-16 - DPLS subarea of the DPL Control Zone (Congestion-event hours by facility): Calendar years 2002 to 2004

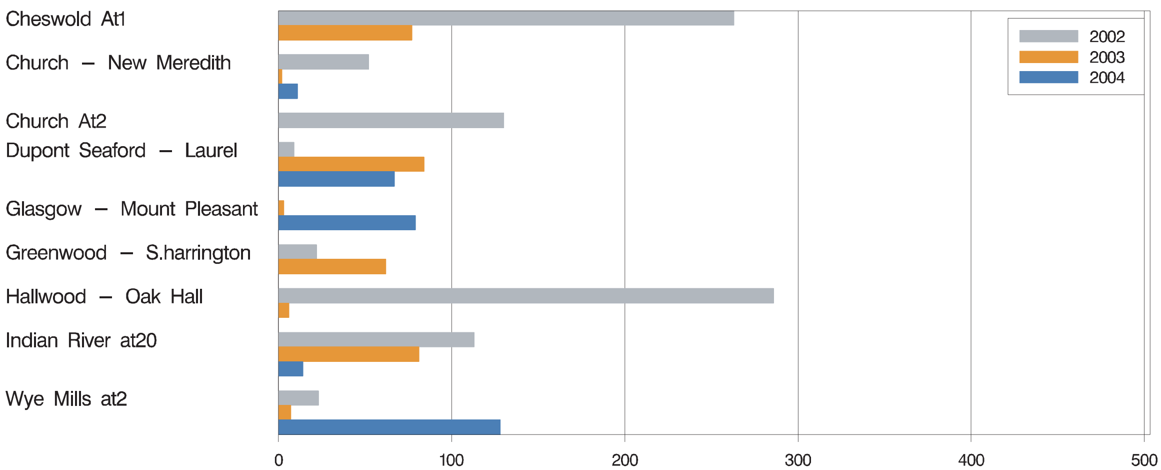
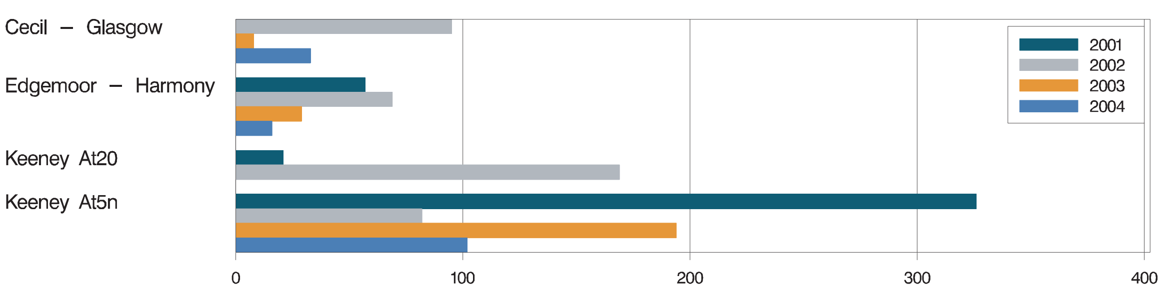


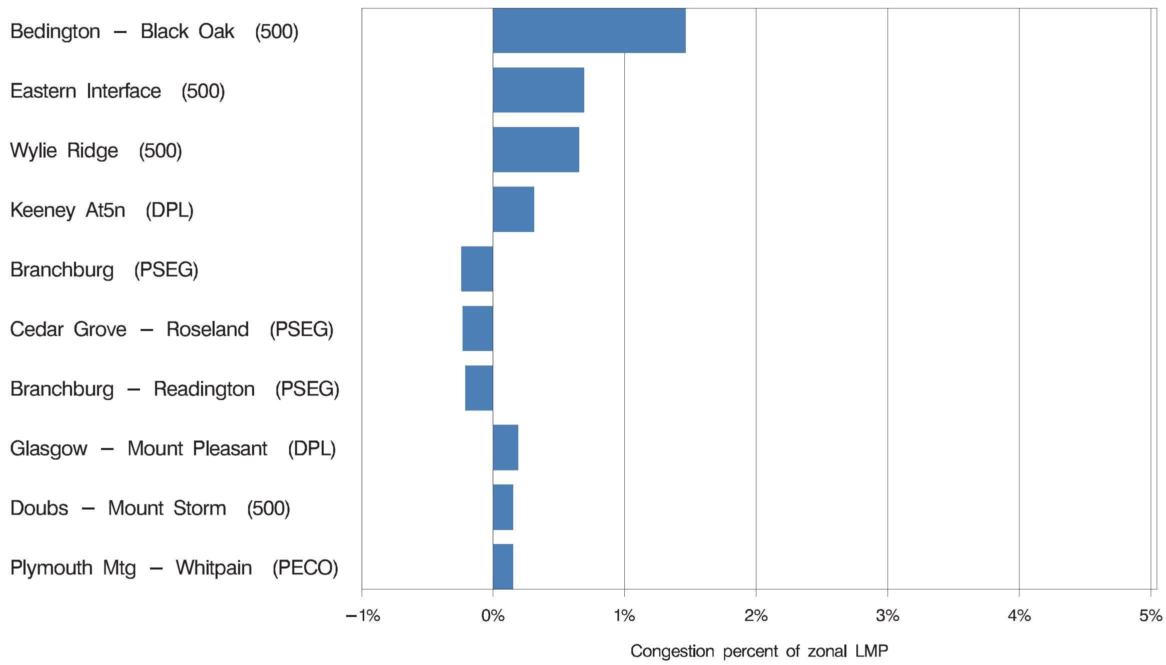
Figure 6-17 presents the same information for the DPLN and SEPJM subareas. The Keeney 500/230 kV transformer (Keeney AT5N), with 102 congestion-event hours, continued to be the most constrained facility in SEPJM although it showed the largest decrease in frequency versus 2003. No other facilities were constrained more than 50 hours in DPLN or SEPJM in 2004.

Figure 6-17 - DPLN and SEPJM subareas of the DPL Control Zone (Congestion-event hours by facility): Calendar years 2001 to 2004



As Figure 6-18 shows, the Bedington-Black Oak, PJM Eastern Interface and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer, Branchburg-Readington and Cedar Grove-Roseland constraints caused the greatest decrease in prices in the DPL zone.

Figure 6-18 - DPL Control Zone congestion components: Calendar year 2004



The JCPL Control Zone, for which no congestion frequency graph is provided, has experienced little internal transmission congestion during the past two years. The JCPL Control Zone experienced 16 congestion-event hours in 2003 and only nine congestion-event hours in 2004.

As Figure 6-19 shows, the Branchburg transformer and Bedington-Black Oak constraints caused the greatest increase in prices while Cedar Grove-Roseland was the only constraint causing a decrease in prices in the JCPL zone.

Figure 6-19 - JCPL Control Zone congestion components: Calendar year 2004

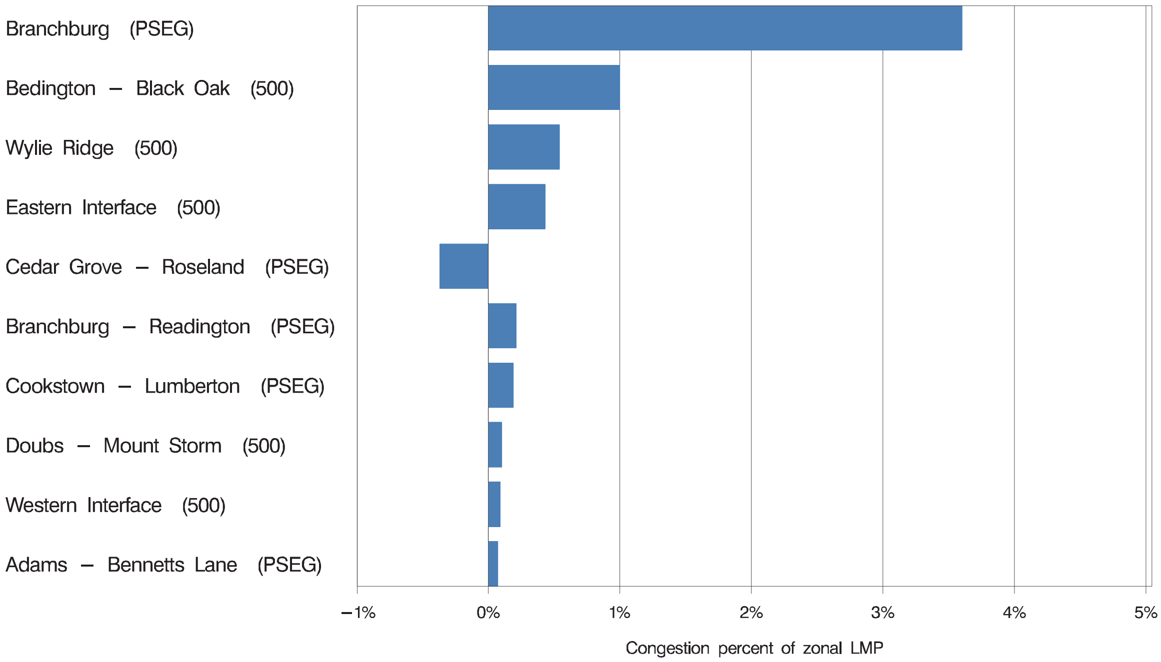
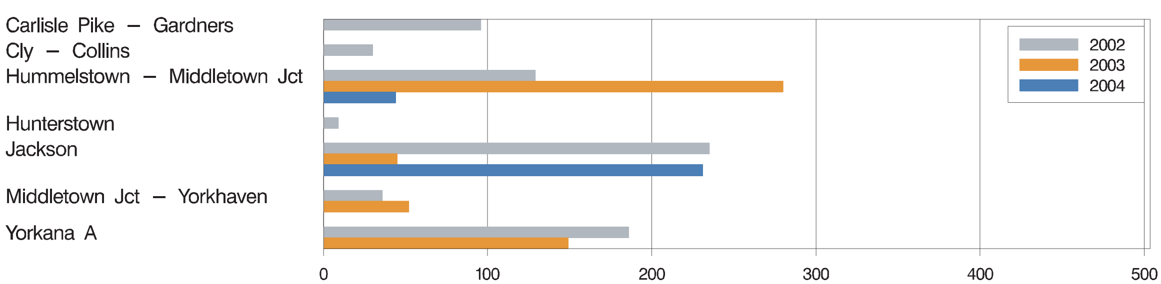


Figure 6-20 illustrates Met-Ed Control Zone constraints. Congestion in Met-Ed was down 219 hours from 2003 levels, a 41 percent reduction. Southcentral Pennsylvania (SCPA) subarea congestion decreased considerably compared to 2003, constituting 18 percent of total Met-Ed congestion-event hours in 2004 as compared to 52 percent during 2003. The largest improvement was on the Hummelstown-Middletown Junction 230 kV line. This had been the most frequently constrained facility in Met-Ed during 2003, but was constrained only 44 hours in 2004. A driver for the 2003 congestion-event hours on the Hummelstown-Middletown Junction 230 kV line was a forced outage on the Middletown Junction-South Lebanon 230 kV line from December 2002 through January 2003. No similar outage affecting the Hummelstown-Middletown Junction line occurred during 2004. Congestion-event hours in the Met-Ed west subarea (MEW) increased slightly as compared to 2003. This was driven largely by the Jackson 230/115 transformer which was constrained 231 hours as compared to 45 hours in 2003, and was the only Met-Ed zonal

Figure 6-20 - Met-Ed Control Zone congestion-event hours by facility: Calendar years 2002 to 2004



facility constrained more than 50 hours in 2004. The Yorkana A transformer which had experienced 149 hours of congestion during 2003 had no congestion during 2004. These year-to-year changes in congestion on Jackson and Yorkana were caused by the return to service in August 2003 of the Hunterstown 500/230 kV transformer, following an outage of approximately one year's duration. That outage had the effect of relieving loading on the Jackson 230/115 kV transformer while simultaneously increasing loading on the Yorkana transformer. The Yorkana A transformer experienced enough unhedgeable congestion during 2003 to trigger the opening of a market solution window. In fact, the PJM economic planning cycle for it began retroactively on August 1, 2003. The Jackson transformer incurred sufficient unhedgeable congestion during 2004 to open a market solution window for it as well.

Figure 6-21 depicts the congestion components of the Met-Ed Control Zone LMP. The Bedington-Black Oak, Jackson transformer and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the Met-Ed zone.

Figure 6-21 - Met-Ed Control Zone congestion components: Calendar year 2004

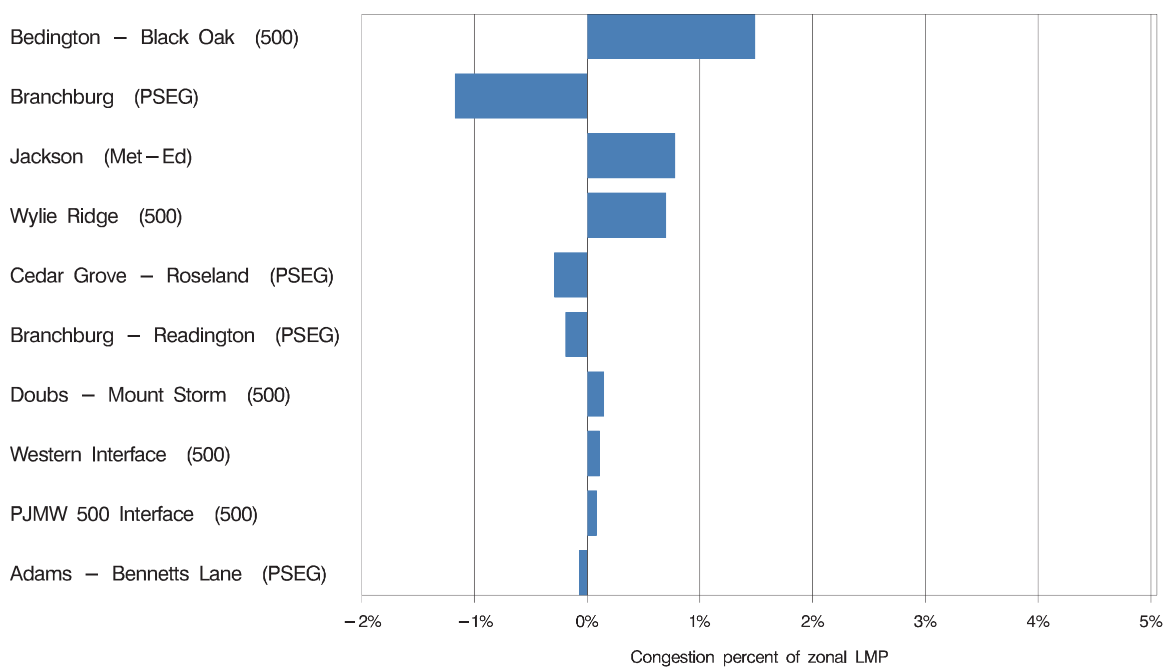


Figure 6-22 illustrates constraints in the PECO Control Zone where in 2004 no facilities were constrained more than 75 hours. Congestion frequency overall was down 58 percent as compared to 2003, with a significant reduction in congestion-event hours in the Plymouth and Whitpain areas of PECO's service territory. In 2004, there were 74 congestion-event hours associated with Plymouth and Whitpain area facilities as compared to 197 hours during 2003. During 2003, these constraints had been caused largely by planned transmission outages at the Plymouth and Whitpain substations in support of upgrades associated with new generator interconnections.

Figure 6-22 - PECO Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

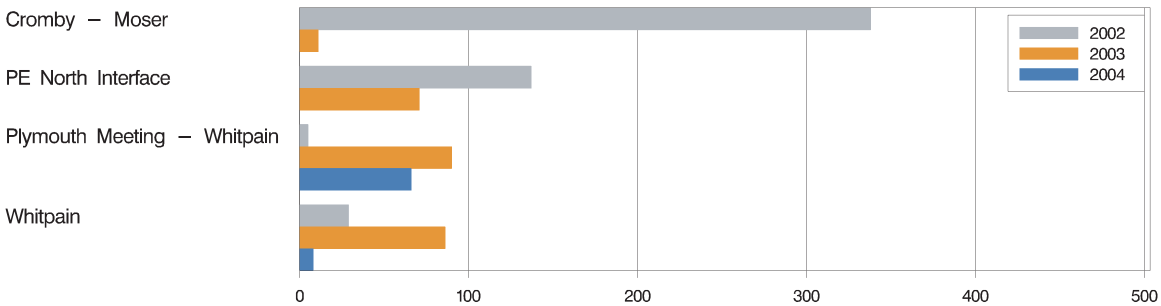


Figure 6-23 shows the congestion components of the PECO Control Zone LMP. The Bedington-Black Oak and Wylie Ridge transformer constraints caused the greatest increase in prices while the Cedar Grove-Roseland and Branchburg-Readington constraints in PSEG caused the greatest decrease in prices in the PECO zone.

Figure 6-23 - PECO Control Zone congestion components: Calendar year 2004

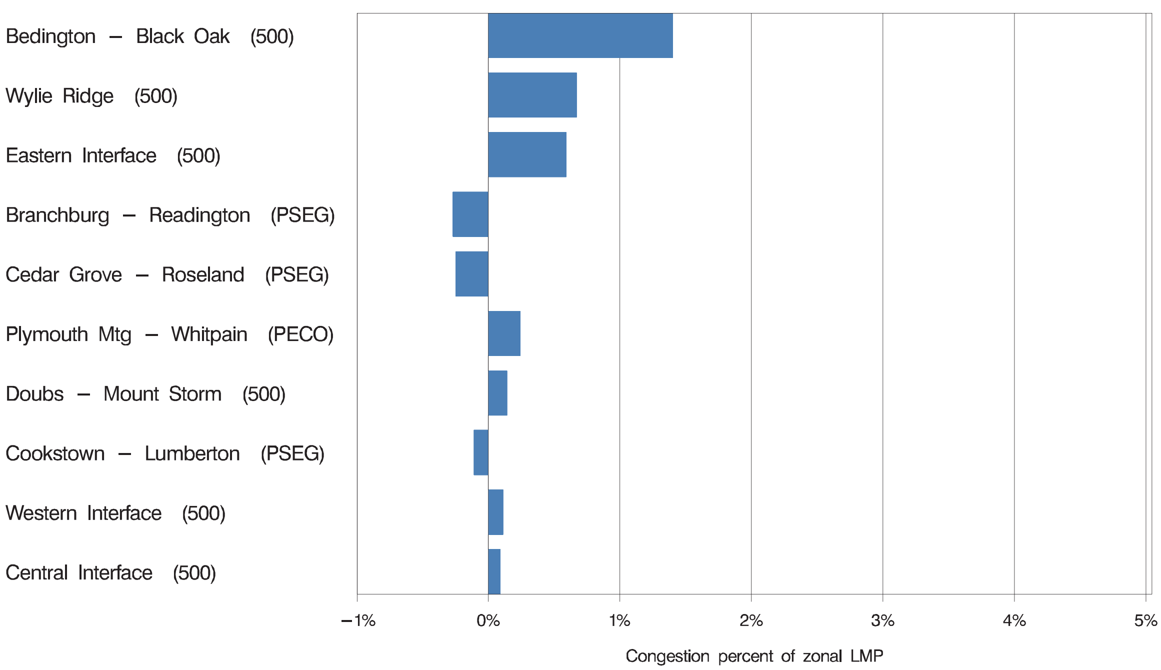


Figure 6-24 illustrates PENELEC Control Zone constraints. Congestion-event hours in the PENELEC Control Zone have steadily declined since reaching a peak of 2,005 hours during 2002. Congestion-event hours in the PENELEC zone were down 67 percent versus 2003, and were considerably lower in northwestern PENELEC. In 2004, the Erie West transformer experienced no congestion, a result of the installation of a second transformer at Erie West. During 2003, this had been the most frequently constrained facility in the northwestern PENELEC (PNNW) subarea. Similarly, the North Meshoppen transformer experienced no congestion in 2004 versus 442 congestion-event hours in 2003 in the northeastern (PNNE) subarea. During 2003, a second transformer was installed at North Meshoppen along with series reactors to address this problem. In total, the PENELEC Control Zone constituted 3 percent of total PJM congestion-event hours during 2004.

Figure 6-24 - PENELEC Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

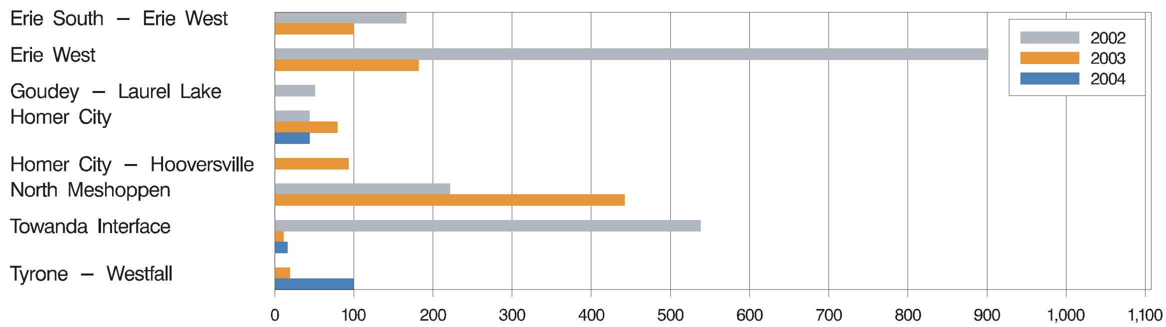
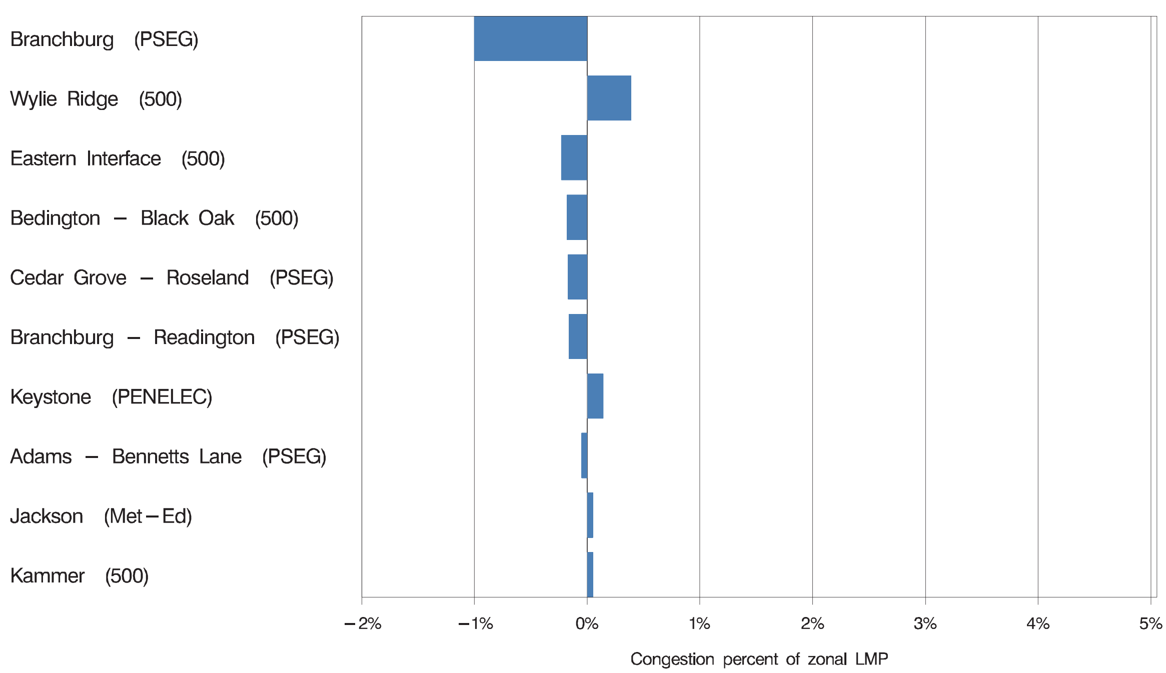


Figure 6-25 shows that the Wylie Ridge transformer constraint caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the PENELEC zone.

Figure 6-25 - PENELEC Control Zone congestion components: Calendar year 2004



The PEPCO Control Zone, for which no congestion frequency figure is shown, has experienced very few internal transmission constraints, with 34 congestion-event hours in 2003 and one congestion-event hour in 2004. While the PEPCO zone itself has experienced few internal constraints, prices there can be affected by congestion elsewhere on the system. As Figure 6-26 shows, the Bedington-Black Oak and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the PEPCO zone.

Figure 6-26 - PEPCO Control Zone congestion components: Calendar year 2004

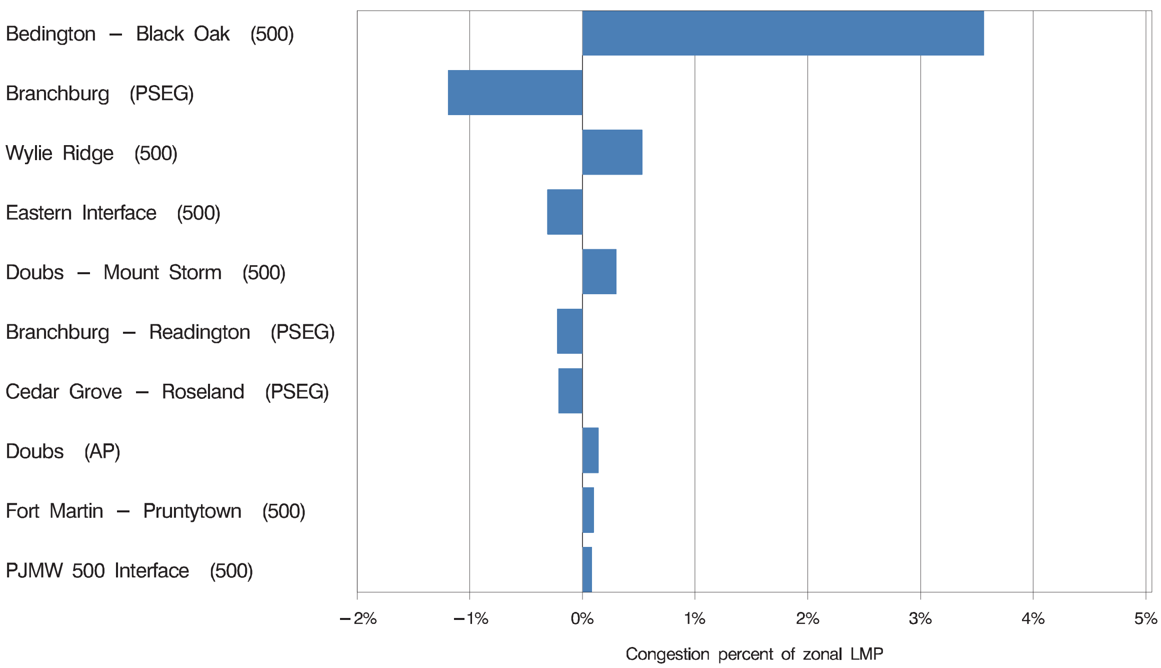


Figure 6-27 illustrates the frequency of PPL Control Zone constraints. During 2004, PPL experienced no significant congestion-event hours. There were eight congestion-event hours for the year, down from 112 congestion-event hours in 2003.

Figure 6-27 - PPL Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

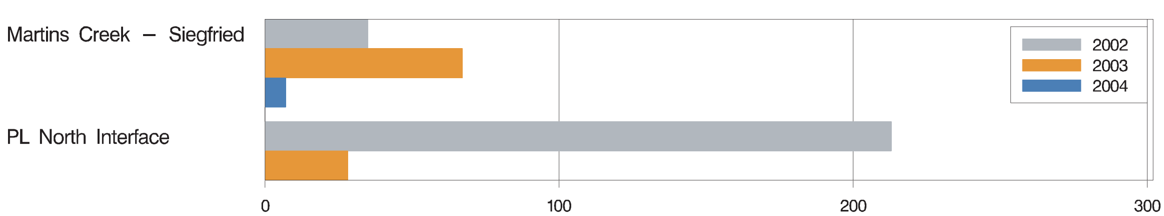


Figure 6-28 shows that the Bedington-Black Oak and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the PPL zone.

Figure 6-28 - PPL Control Zone congestion components: Calendar year 2004

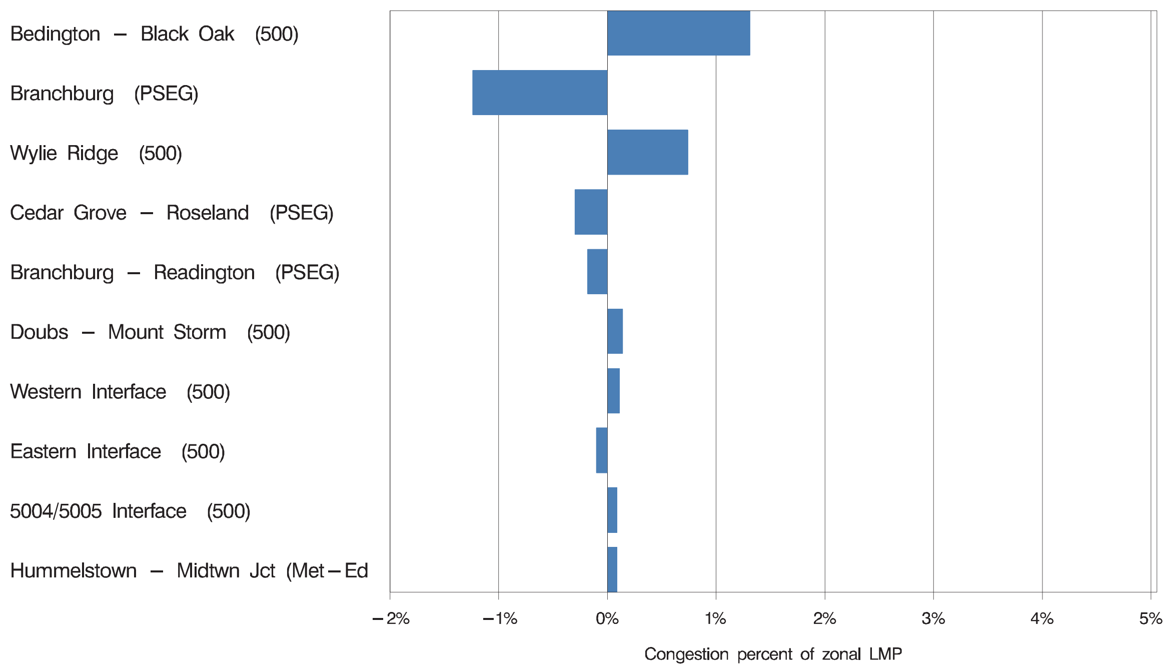


Figure 6-29 illustrates constraint occurrences in the PSEG Control Zone. Total congestion frequency in PSEG was 2 percent lower in 2004 versus 2003. The three facilities that were the most often constrained in PSEG during 2003 had the largest reductions in congestion-event hours in 2004. Cedar Grove-Roseland 230, which affects approximately one-half of PSEG zone load, and two northcentral PSEG (PSNC) facilities, Branchburg-Readington 230 and Edison-Meadow Road 138 kV, had a combined reduction in congestion of 1,044 hours. These reductions were caused, in large part, by the rating reduction on the Branchburg transformers which had the effect of limiting imports into the northern PSEG Control Zone and reducing the loading on these facilities. PSEG had the second most frequently constrained facility in PJM during 2004, the Branchburg 500/230 kV transformers. The Branchburg 500/230 kV transformers comprised 56 percent of all congestion-event hours in the PSEG zone and 9 percent of all PJM congestion. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg number 1 and number 2 transformers because of a deteriorating condition identified during an inspection. On May 25, 2004, a special protection scheme (SPS) was installed at Branchburg to reduce the impact on congestion from the derated facilities. A third transformer is scheduled to be installed at Branchburg by June 30, 2005, to relieve this constraint. The number 1 and number 2 transformers at Branchburg are scheduled to be replaced by June 2007.

Figure 6-29 - PSEG Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

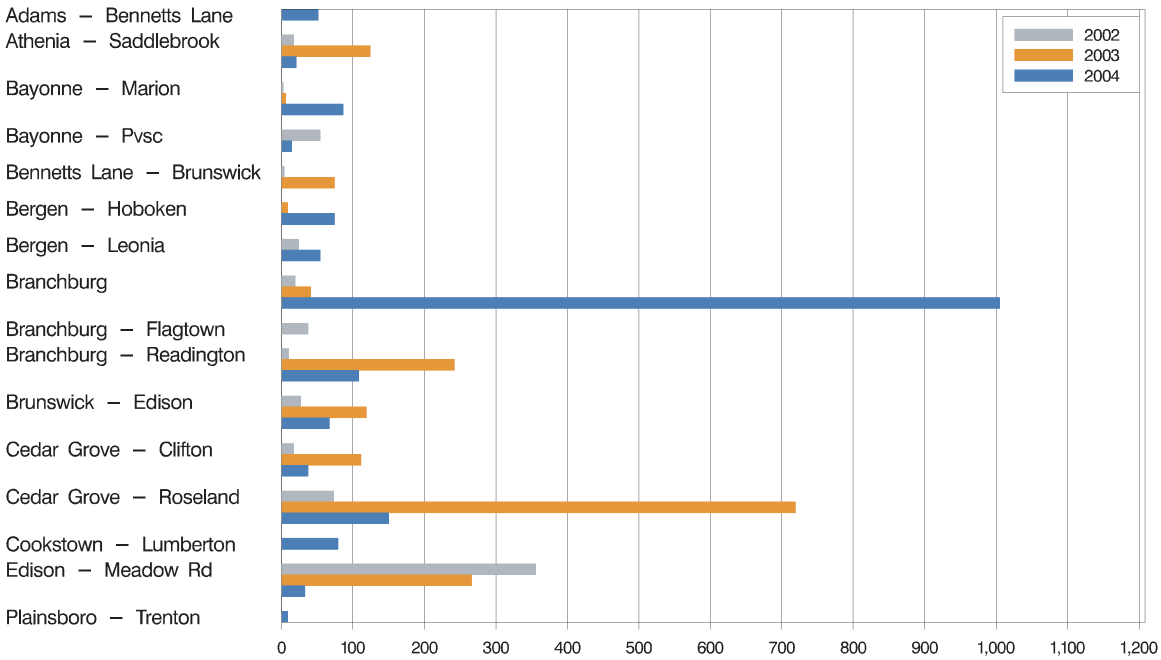


Figure 6-30 shows that the Branchburg transformer, a PSEG Control Zone facility, and the Bedington-Black Oak constraints increased prices in the PSEG Control Zone. There were no constraints that significantly reduced prices in PSEG zone during 2004.

Figure 6-30 - PSEG Control Zone congestion components: Calendar year 2004

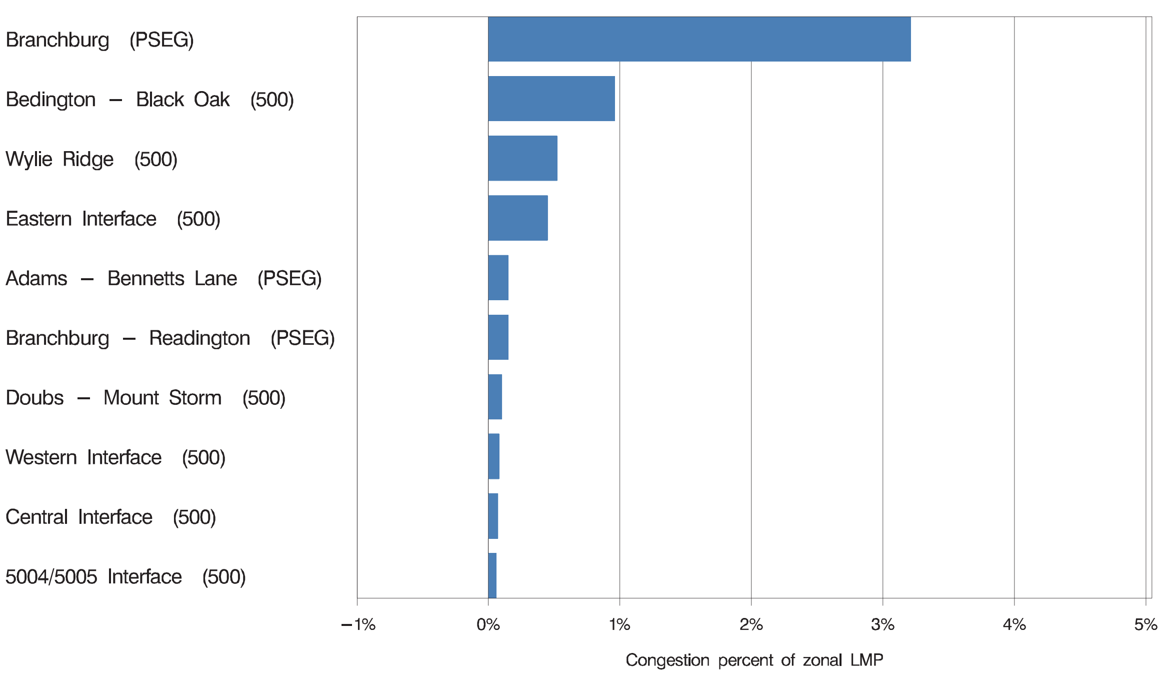


Figure 6-31 illustrates constraint occurrences in the ComEd Control Zone after its integration into PJM. Since May 1, congestion frequency levels in ComEd have been comparatively low, with only 130 congestion-event hours during the eight-month period comprising Phases 2 and 3 of calendar year 2004. The most significant constraint was the Waukegan-Round Lake 138 kV line with 97 congestion-event hours. Congestion experience in the ComEd zone was minimized by post-contingency switching procedures which are employed where PJM would traditionally have initiated out of merit dispatch. Also contributing to the low level of congestion is that a number of large generators, primarily located in the eastern portion of the ComEd system, often ran independent of PJM economic dispatch. This had the effect of reducing west-to-east flows on facilities that might otherwise have been subject to congestion.

Figure 6-31 - ComEd Control Zone congestion-event hours by facility: Phases 2 and 3, 2004

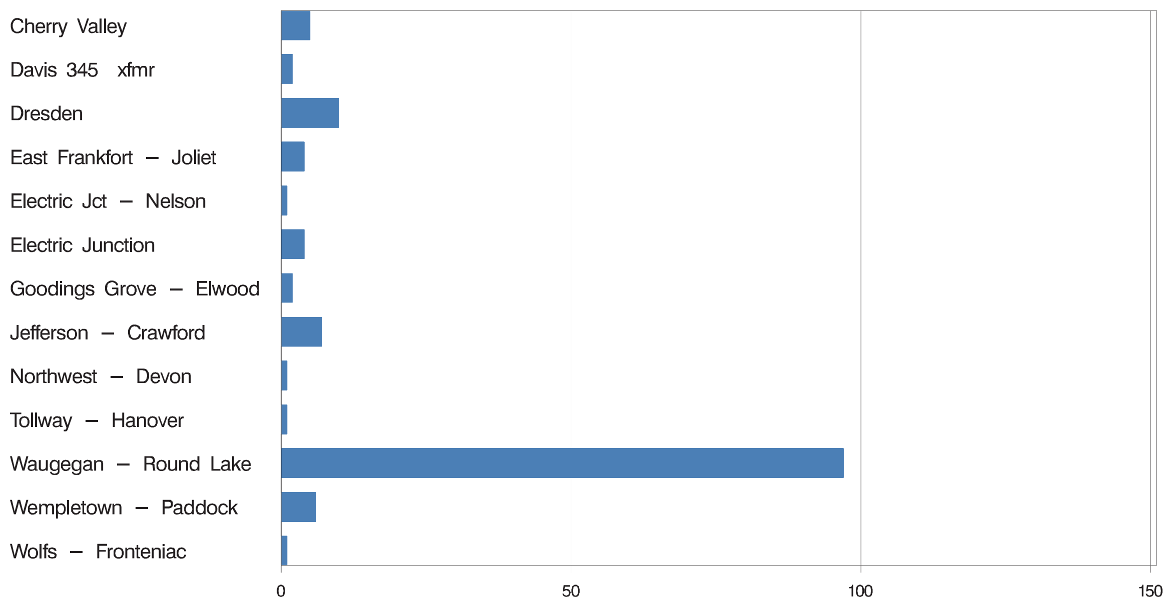


Figure 6-32 depicts congestion components of the ComEd Control Zone LMP during Phases 2 and 3. As one can see, the Phase 2 Pathway between the PJM and ComEd Control Areas was the most significant congestion component of ComEd price. The Pathway reduced prices in ComEd overall, consistent with the fact that Pathway flow was predominantly from the ComEd into the PJM Control Area. Such flows placed ComEd on the unconstrained side of the interface, thus tending to depress prices relative to the other PJM Control Area. Constraints on the Branchburg transformer, the Bedington-Black Oak line and the Crete – St. Johns Tap line, a Midwest ISO flowgate, also reduced prices in ComEd. There were no constraints that significantly increased prices in the ComEd zone during 2004.

Figure 6-32 - ComEd Control Zone congestion components: Phases 2 and 3, 2004

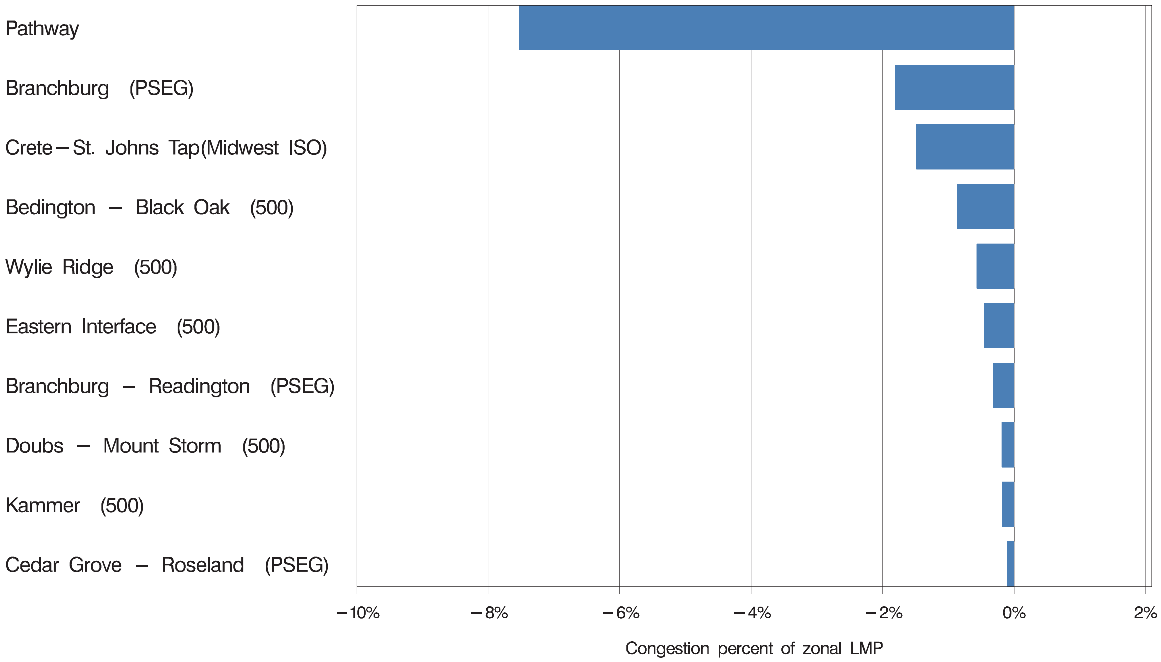
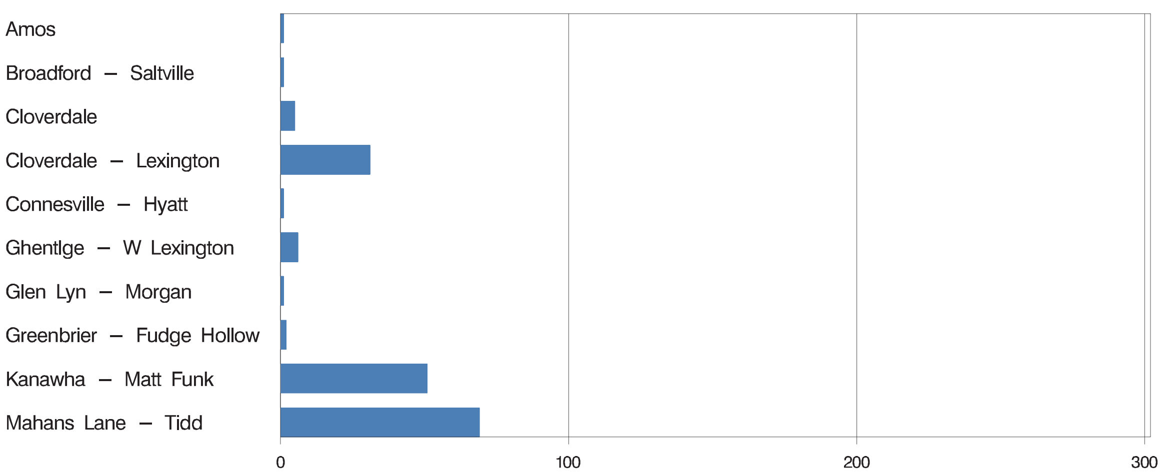


Figure 6-33 illustrates constraint occurrences in the AEP Control Zone since its Phase 3 integration into PJM. The Kanawah-Matt Funk 345 kV line experienced 51 hours of congestion between October 1, 2004, and December 31, 2004. AEP currently has a 765 kV line under construction from Wyoming to Jackson's Ferry that should reduce congestion on Kanawah-Matt Funk after its June 2006 in-service date.[19] Also congested was the Mahans Lane-Tidd 138 kV line with 69 congestion-event hours during Phase 3. Before the integration, congestion on these facilities had been managed through the use of NERC TLRs. Since then, however, given PJM's reliance on LMP, the impacts of these constraints have become more localized.

Figure 6-33 - AEP Control Zone congestion-event hours by facility: Phase 3, 2004



19 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket Nos. ER04-539-001, 002 and ER04-121-000 (October 26, 2004), Report of the PJM Market Monitor, paragraph 17.

Figure 6-34 shows that the Wylie Ridge and PJM Eastern Interface constraints caused the greatest reduction in prices in the AEP zone. There were no constraints that significantly increased prices in the AEP zone during 2004.

Figure 6-34 - AEP Control Zone congestion components: Phase 3, 2004

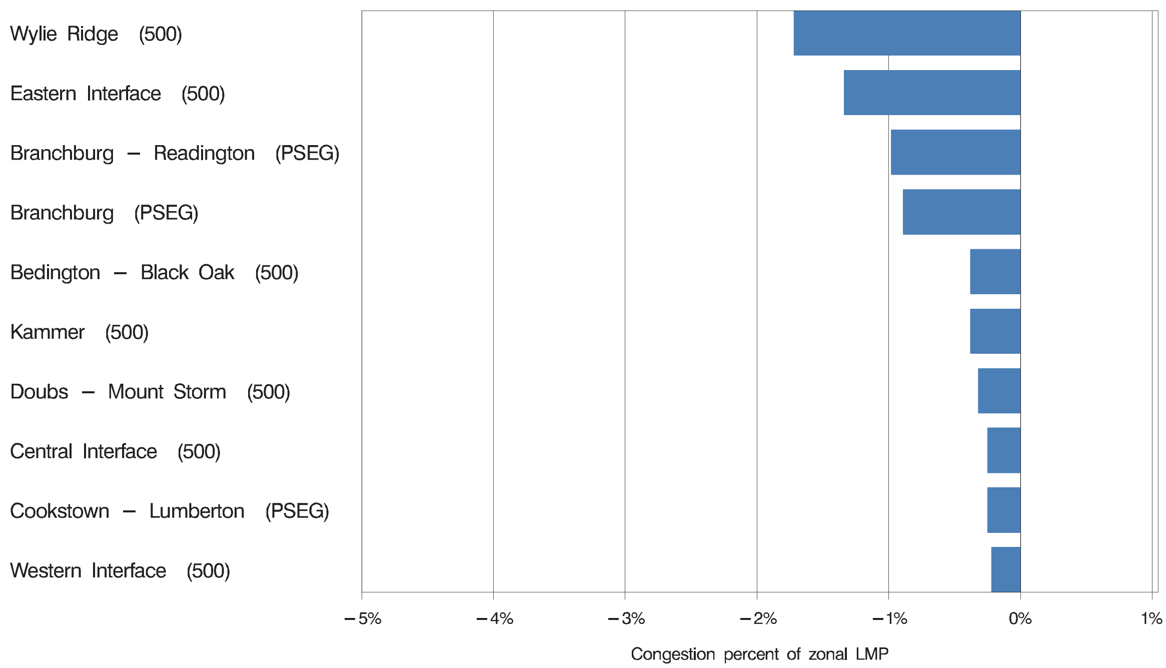


Figure 6-35 illustrates constraint occurrences in the DAY Control Zone which has experienced only 19 hours of congestion since its Phase 3 integration into PJM.

Figure 6-35 - DAY Control Zone congestion-event hours by facility: Phase 3, 2004

Figure 6-36 depicts the congestion components of the DAY Control Zone's LMP. The influence of constraints on prices in the DAY zone very closely mirrored that of the AEP zone. The Wylie Ridge and PJM Eastern Interface constraints caused the greatest reduction in prices in the DAY zone. There were no constraints that significantly increased prices in the DAY zone during 2004.

Figure 6-36 - DAY Control Zone congestion components: Phase 3, 2004

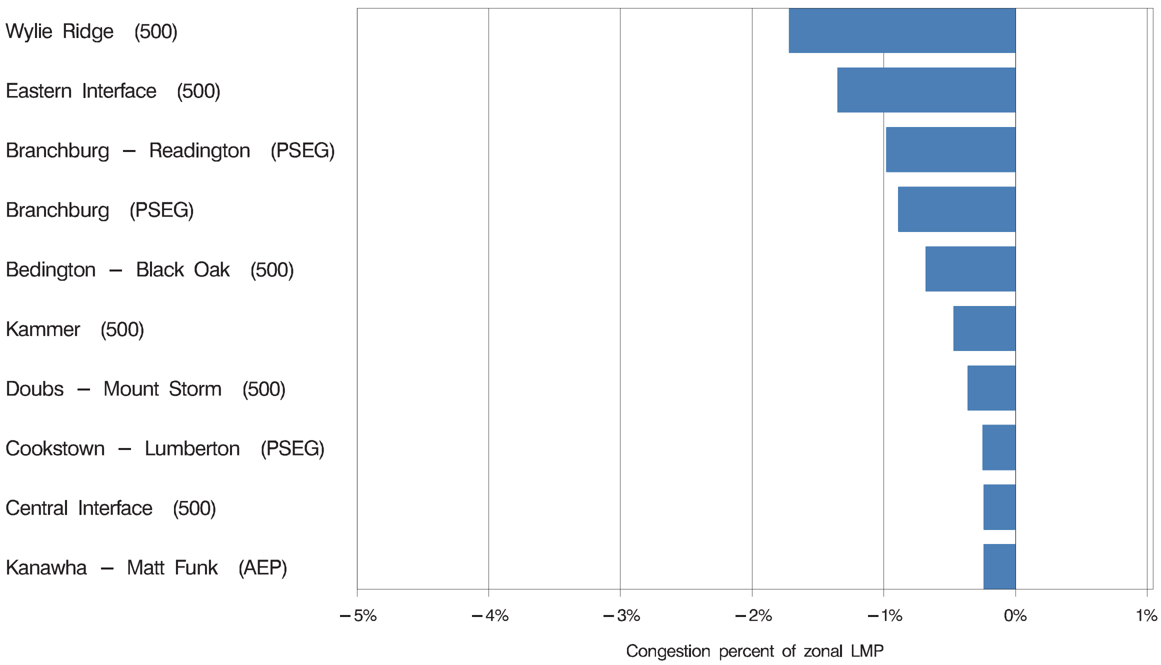


Table 6-6 lists congestion-event hours by facility type and voltage.

Table 6-6 - Congestion-event hour summary by facility type and voltage class: Calendar years 2001 to 2004

Type	Voltage (kV)	Congestion-Event Hours 2001	2002	2003	2004	% of Congestion-Event Hours 2001	2002	2003	2004
All	All	8,435	11,662	9,711	*11,205	100%	100%	100%	100%
	500	759	1,888	1,985	1,809	9%	16%	20%	16%
	345	38	1,084	705	1,115	0%	9%	7%	10%
	230	1,625	1,474	3,016	2,340	19%	13%	31%	21%
	138	744	2,056	1,071	977	9%	18%	11%	9%
	115	1,154	2,527	1,018	534	14%	22%	10%	5%
	69	4,115	2,619	1,916	1,918	49%	22%	20%	17%
	34	0	14	0	0	0%	0%	0%	0%
Midwest ISO Flowgate	All	-	-	-	455	-	-	-	4%
	500	-	-	-	0	-	-	-	0%
	345	-	-	-	369	-	-	-	3%
	230	-	-	-	4	-	-	-	0%
	138	-	-	-	82	-	-	-	1%
Interface	All	752	1,683	1,274	1,018	9%	14%	13%	9%
	500	747	586	764	397	9%	5%	8%	4%
	345	0	5	0	0	0%	0%	0%	0%
	230	0	388	103	0	0%	3%	1%	0%
	115	0	538	11	16	0%	5%	0%	0%
	69	5	166	396	605	0%	1%	4%	5%
Line	All	5,507	5,552	5,590	4,622	65%	48%	58%	41%
	500	12	1,128	917	1,328	0%	10%	9%	12%
	345	38	233	168	99	0%	2%	2%	1%
	230	1,164	658	2,104	996	14%	6%	22%	9%
	138	408	1,163	815	756	5%	10%	8%	7%
	115	214	413	187	280	3%	4%	2%	2%
	69	3,671	1,943	1,399	1,163	44%	17%	14%	10%
	34	0	14	0	0	0%	0%	0%	0%
Transformer	All	2,176	4,427	2,847	2,598	26%	38%	29%	23%
	500	0	174	304	84	0%	1%	3%	1%
	345	0	846	537	647	0%	7%	6%	6%
	230	461	428	809	1,340	5%	4%	8%	12%
	138	336	893	256	139	4%	8%	3%	1%
	115	940	1,576	820	238	11%	14%	8%	2%
	69	439	510	121	150	5%	4%	1%	1%

*Total includes an additional 2,512 congestion-event hours attributable to the Pathway between ComEd and PJM during Phase 2.

Post-Contingency Congestion Management Program

The PJM "Transmission Operations Manual" states in relevant part:

> The PJM RTO Bulk Power Electric Supply System is operated so that loading on all PJM Monitored Bulk Power Transmission Facilities are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings.[20]

In part in response to stakeholders' concerns regarding congestion on the Delmarva Peninsula, PJM developed, tested and implemented a protocol that results in less frequent out of merit dispatch than had been the case under the then-current system.

On August 19, 2004, the FERC accepted PJM's plan.[21] The program was implemented on September 1, 2004. The FERC noted that the expansion of this program has the potential to:

- Reduce redispatch costs in chronically congested areas in the PJM region;
- More accurately reflect the local benefits of avoided redispatch and enhanced reliability;
- Reduce the potential for the exercise of local market power;
- Reduce emissions; and
- Allow for more efficient use of assets.

Under this post-contingency congestion management protocol, a facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start capability or switching to respond to the loss of a facility. PJM continues to evaluate candidate facilities for inclusion under this protocol. The Jackson and Yorkana transformers in Met-Ed were added to the program during 2004.

PJM Economic Planning Process

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of regional transmission organizations. PJM implements this function pursuant to the RTEPP set forth in Schedule 6 of the PJM Operating Agreement. A key part of this regional planning protocol is the evaluation of both generation interconnection and merchant transmission interconnection requests, the procedures for which are codified under Part IV of the PJM Open Access Transmission Tariff.

PJM's RTEPP includes an economic planning component that is still under development. The FERC approved the PJM economic transmission planning process in October 2003 and it began retroactively with the regional planning cycle that started on August 1, 2003.

The objective of the economic planning component of the regional transmission planning protocol

20 See PJM manual, "Transmission Operations (m03), Revision 12" (October 1, 2004).
21 108 FERC ¶ 61,196 (2004).

is to provide cost-effective transmission solutions to alleviate unhedgeable congestion that no market participant has proposed to resolve. Unhedgeable congestion is transmission system congestion with a cost that PJM finds cannot be mitigated by economic generation, FTRs or other financial instruments available pursuant to its Tariff or under the Operating Agreement.

PJM posts the hourly shadow price, along with the hourly and cumulative monthly total gross congestion cost of each constraint. When the cumulative monthly total gross congestion cost of a constraint exceeds the applicable initial threshold, PJM posts a notice to that effect and begins determining the extent to which the total affected load cannot be hedged.

PJM posts the hourly and cumulative monthly unhedgeable congestion associated with each constraint for which it undertakes such calculations, as well as the portions of unhedgeable congestion attributable to recurring and nonrecurring causes of transmission constraints. When the cumulative monthly unhedgeable congestion associated with a constraint exceeds the applicable market threshold, PJM posts a notice advising that it will begin an initial cost-benefit analysis of potential transmission enhancements that would relieve the applicable transmission constraint. PJM then opens a one-year "market window" to solicit merchant solutions.

Market-based proposals solicited during the market window may take many forms including generation, transmission or demand-side response solutions. A market-based solution differs from a traditional utility solution because it may be proposed by an entity other than the regulated transmission owner. If no market-based solution is proposed within one year from the date of publication of the results of the initial cost-benefit analysis, PJM will include in the "PJM Regional Transmission Expansion Plan"[22] the transmission enhancement that is the most cost-effective, feasible solution.

Table 6-7 identifies the facilities for which a market window has been opened. Depending upon their initiation dates, market windows for these facilities will close beginning in March 2005. Proposed solutions may only be designated as a "market solution," and thus be eligible for expedited processing, following the close of the associated market window and by request of the developer. No proposals as yet carry this designation as the first market window will close on March 4, 2005.

22 See "PJM Regional Transmission Expansion Plan" (Revised August 1, 2004) <http://www.pjm.com/planning/rtep-baseline-reports/downloads/regionalplan_5_0.chm)> (6.8 KB).

Table 6-7 - Constraints with open market window

One Year Market Window is Open for the Following Congested Facilities	Market Window Open Date	Market Window Close Date	Location of Facility Based on Transmission Owner Zones
Adams - Brunswick 230 kV "X-2224"	4-Mar-04	4-Mar-05	PSEG
Bedington - Black Oak 500 kV (Voltage)	4-Mar-04	4-Mar-05	AP
Bedington - Black Oak 500 kV (Thermal)	4-Mar-04	4-Mar-05	AP
Greystone - Portland 230 kV	4-Mar-04	4-Mar-05	Met-Ed / JCPL
PJM West 500 kV	4-Mar-04	4-Mar-05	Multiple Zones
North Wales - Whitpain 230 kV	4-Mar-04	4-Mar-05	PECO
Eastern Interface	4-Mar-04	4-Mar-05	Multiple Zones
Jackson 230/115 kV	4-Mar-04	4-Mar-05	Met-Ed
Yorkana 230/115 kV	4-Mar-04	4-Mar-05	Met-Ed
Cedar Grove - Clifton 230 kV "K-2263"	4-Mar-04	4-Mar-05	PSEG
Adams - Bennetts Lane 230 kV "X-2224"	4-Mar-04	4-Mar-05	PSEG
Brunswick - Edison 138 kV	4-Mar-04	4-Mar-05	PSEG
Sheildalloy - Vineland 69 kV	4-Mar-04	4-Mar-05	AECO
Edison - Meadow Road 138 kV "R-1318"	4-Mar-04	4-Mar-05	PSEG
Elroy - Hosensack 500 kV	4-Mar-04	4-Mar-05	PECO / PPL
Edgewood - N. Salisbury 69 kV	4-Mar-04	4-Mar-05	DPL
Cedar Interface	4-Mar-04	4-Mar-05	AECO
Northern PECO Voltage Interface	4-Mar-04	4-Mar-05	PECO
Athenia - Saddlebrook 230 kV	4-Mar-04	4-Mar-05	PSEG
Central Interface	4-Mar-04	4-Mar-05	Multiple Zones
Laurel - Woodstown 69 kV	4-Mar-04	4-Mar-05	AECO
DuPont Seaford - Laurel 69 kV	4-Mar-04	4-Mar-05	DPL
Western Interface	4-Mar-04	4-Mar-05	Multiple Zones
Landis - Minotola 69 kV	4-Mar-04	4-Mar-05	AECO
Sammis - Wylie Ridge 345 kV	4-Mar-04	4-Mar-05	AP
Lewis - Motts Farm 69 kV	4-Mar-04	4-Mar-05	AECO
Plymouth Meeting - Whitpain 230 kV "220-14"	4-Mar-04	4-Mar-05	PECO
Keeney 500/230 kV "AT51"	4-Mar-04	4-Mar-05	DPL
Plymouth Meeting - Whitpain 230 kV "220-13"	4-Mar-04	4-Mar-05	PECO
Martins Creek - Morris Park 230 kV	4-Mar-04	4-Mar-05	PPL / JCPL
Bergen - Leonia 230 kV	1-Apr-04	1-Apr-05	PSEG
Bergen - Hoboken 230 kV	1-Apr-04	1-Apr-05	PSEG
Wylie Ridge 500/345 kV #5	1-Apr-04	1-Apr-05	AP
Harrison - Kammer Tap 500 kV	1-Apr-04	1-Apr-05	AP
Branchburg 500/230 kV #1	18-May-04	18-May-05	PSEG
Branchburg 500/230 kV #2	18-May-04	18-May-05	PSEG
Wylie Ridge 500/345 kV #7	20-Jul-04	20-Jul-05	AP
Keeney 500/230 kV "AT50"	20-Jul-04	20-Jul-05	DPL
Branchburg - Flagtown 230 kV	20-Jul-04	20-Jul-05	PSEG
Bayonne - Marion 138 kV	29-Nov-04	29-Nov-05	PSEG
Roseland - Whippany 230 kV	29-Nov-04	29-Nov-05	JCPL/PSEG
Jackson 230/115 kV "5"	29-Nov-04	29-Nov-05	Met-Ed
Glasgow - Mt Pleasant 138 kV	29-Nov-04	29-Nov-05	DPL
Richmond - Waneeta 230 kV	29-Nov-04	29-Nov-05	PECO
Red Lion 500/230 kV "AT50"	29-Nov-04	29-Nov-05	DPL
Doubs - Mt Storm 500 kV	29-Nov-04	29-Nov-05	APS/VAP
Beckett - Paulsboro 69 kV	29-Nov-04	29-Nov-05	AECO
Hudson 230/138 kV #2	29-Nov-04	29-Nov-05	PSEG
Brunner - Yorkana 230 kV	29-Nov-04	29-Nov-05	PPL/Met-Ed
Wye Mills 138/69 kV "AT-2"	29-Nov-04	29-Nov-05	DPL
Sickler 230/69 kV #1	29-Nov-04	29-Nov-05	AECO
Cedar - Sands Point 69 kV	29-Nov-04	29-Nov-05	AECO
Talbot-Trappe 69 kV	29-Nov-04	29-Nov-05	DPL
Fort Martin - Prutytown 500 kV	1-Dec-04	1-Dec-05	AP

SECTION 7 - FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

In PJM, Financial Transmission Rights (FTRs) have been available to firm point-to-point and network service transmission customers[1] as a hedge against congestion costs since the inception of locational energy pricing on April 1, 1998. These firm transmission customers have access to FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm customers receive requested FTRs to the extent that they are consistent both with the physical capability of the transmission system and with other eligible customers' FTR requests.

Effective June 1, 2003,[2] PJM replaced the allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) and an associated Annual FTR Auction. The process for allocating ARRs is identical to the previous process for allocating FTRs, but the revenues received for the allocated ARRs are based on the results of the Annual FTR Auction. Firm transmission customers have the option either to take ARRs or to take the underlying FTRs through a process called self-scheduling.

PJM also runs monthly auctions designed to permit bilateral FTR sales and to allow eligible participants to buy any residual system FTRs. For the 2003 to 2004 planning period, PJM introduced 24-hour FTRs into the monthly auctions. At the same time, PJM also added annual and monthly FTR options. Unlike standard FTRs, the options can never be a financial liability.

ARRs and FTRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. ARRs provide holders with revenues or charges based on the locational price difference between ARR sources (origins) and sinks (destinations) determined in the Annual FTR Auction.[3] In other words, ARR revenues are a function of FTR auction participants' expectations of locational price differences in the Day-Ahead Energy Market. FTRs provide holders with revenues or charges based on the locational price differences actually experienced in the Day-Ahead Energy Market.

ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power. Both can, however, help protect load-serving entities (LSEs) and other market participants from congestion costs in the PJM Day-Ahead Energy Market. Market participants can also hedge against real-time congestion by matching real-time energy schedules with day-ahead energy schedules.

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1.** The four-month period from January 1 through April 30, 2004, when PJM was comprised of 12 zones.[4] Eleven of these [i.e., 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),

1 PJM network and firm, long-term point-to-point transmission service transmission customers are referred to as eligible customers.
2 87 FERC ¶ 61,054 (1999).
3 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.
4 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The 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 the 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.

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)] comprised the Mid-Atlantic Region. The remaining zone, the Allegheny Power Company Control Zone (AP), comprised the PJM Western Region.

- **Phase 2.** 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).[5]

- **Phase 3.** 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.

ARRs were available throughout the PJM Mid-Atlantic Region for the 2004 to 2005 planning period, while both ARRs and direct allocation FTRs were available to eligible market participants in the AP and ComEd Control Zones. Eligible customers in the AEP and DAY Control Zones received phase-in FTRs to carry them to the start of the next planning period. [6]

Overview

Market Structure

- **ARR Supply and Demand.** Total demand in the annual ARR allocation was 55,128 MW for the 2004 to 2005 planning period, up from 39,888 MW during the 2003 to 2004 planning period. ARR demand is limited by total amount of network and long-term, firm point-to-point transmission service. ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs, and numerous combinations of ARRs are feasible. The Bedington-Black Oak interface and the Eastern Interface were the principal constraints limiting supply.

  In response to an order by the United States Federal Energy Regulatory Commission (FERC),[7] PJM proposed changes to its FTR and ARR allocation processes that would allow certain long-term, firm point-to-point transmission service customers to participate in Stage 1 of the annual ARR allocation, thereby putting them on equal footing with network transmission service customers if transmission constraints occur in the ARR and FTR simultaneous feasibility test (SFT).

  PJM market rules automatically reassign ARRs and their associated revenue when load switches among LSEs. Nearly 34,000 MW of ARRs associated with $264,300 per MW-day of revenue were automatically reassigned during the period from June 2003 through December 2004. Individual MW of load may be reassigned multiple times over a period.

5 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).
6 The PJM planning period begins on June 1 and ends 12 months later on May 31. Annual FTR accounting changed from calendar years to planning periods beginning with the 2003 to 2004 planning period. The transition to this new accounting period required the 2003 calendar year accounting to be extended by five months to encompass January 1, 2003, through May 31, 2004. The 2004 to 2005 planning period began on June 1, 2004, and will end on May 31, 2005.
7 106 FERC ¶ 61,049 (2004).

- **FTR Supply and Demand.** Total Annual FTR Auction demand was 861,323 MW during the 2004 to 2005 planning period. Under the Annual FTR Auction, there is no limit on demand. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs, and numerous combinations of feasible FTRs. The derated Branchburg 500/230 transformer, the Bedington-Black Oak interface, the Wylie Ridge 500/345 transformer and the Kanawha River-Matt Funk 345 line were the principal constraints limiting supply. Total demand for annual FTR allocations was 62,830 MW during the 2004 to 2005 planning period.

Market Performance

- **FTR Price.** For the 2004 to 2005 planning period, just over 80 percent of Mid-Atlantic Region annual FTRs were purchased for less than $1 per MWh and 90 percent for less than $2 per MWh, while 99.9 percent of ComEd Control Zone annual FTRs were purchased for less than $1 per MWh. The overall average prices paid for annual FTR obligations were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. Comparable prices for the 2003 to 2004 planning period were $1.09 per MWh for 24-hour, $0.34 per MWh for on-peak and $0.15 per MWh for off-peak FTRs. The overall average prices paid for 2004 to 2005 planning period annual FTR obligations and options were $0.31 per MWh and $0.19 per MWh, respectively, compared to $0.37 per MWh and $0.23 per MWh, respectively, in the 2003 to 2004 planning period. Average prices in Monthly FTR Auctions have dropped from $0.51 per MWh in 2002, to $0.27 MWh in 2003, to $0.10 MWh in 2004.

- **ARR Revenue.** Annual and Monthly FTR auction revenue is allocated to ARR holders based on ARR target allocations. PJM collected $358 million in FTR auction revenue during the 2003 to 2004 planning period and $379 million during the 2004 to 2005 planning period through the end of calendar year 2004.

- **FTR Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $680 million of congestion revenues during the 2003 to 2004 planning period and $627 million during the 2004 to 2005 planning period through the end of calendar year 2004.[8]

- **ARR Revenue Adequacy.** ARRs were 100 percent revenue adequate during the 2003 to 2004 and the 2004 to 2005 planning periods. ARR holders received credits valued at $311 million during the 2003 to 2004 planning period, with an average hourly ARR credit of $1.23 per MWh. ARR holders will receive credits valued at $345 million during the 2004 to 2005 planning period, with an average hourly ARR credit of $1.17 per MWh.

- **FTR Revenue Adequacy.** FTRs were 98 percent revenue adequate during the 2003 to 2004 planning period, receiving credits valued at $680 million. FTRs through December 31, 2004, of the planning period ending May 31, 2005, have been paid at 97 percent of the target allocation level.[9]

8 See Section 6, "Congestion," at Table 6-2, "Monthly PJM congestion accounting summary [Dollars (in millions)]: By planning period."
9 See Section 6, "Congestion," for a more complete discussion of FTR revenue adequacy.

- **ARR Volume.** Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW were allocated. Eligible market participants subsequently self-scheduled 13,061 MW of these allocated ARRs as annual FTRs, effectively leaving 20,528 MW of ARRs outstanding. Of 39,888 MW in ARR requests for the 2003 to 2004 planning period, 28,933 MW were allocated. Eligible market participants subsequently self-scheduled 13,986 MW of these allocated ARRs as annual FTRs, effectively leaving 14,947 MW of ARRs outstanding.

- **FTR Volume.** Of 924,154 MW in annual FTR requests for the 2004 to 2005 planning period, 177,434 MW were allocated.

The Annual ARR Allocation and Annual FTR Auction together provide long-term, firm transmission customers with a mechanism to hedge congestion and provide all eligible market participants increased access to long-term FTRs. The Annual FTR Auction allows a market valuation of FTRs that is consistent with the most efficient use of such financial instruments. The 2004 FTR auction process results were competitive and succeeded in providing all qualified market participants with equal access to FTRs. By explicitly providing that beneficial ARRs follow load as load shifts among suppliers, the rules remove a potential barrier to competition.

Auction Revenue Rights

ARRs are financial instruments that entitle their holders to receive revenue based on prices in the Annual FTR Auction. The ARR target allocation (i.e., what the ARR holder should receive) is equal to the product of the ARR MW and the sink-minus-source price difference from the Annual FTR Auction. An ARR's value can be positive or negative depending on these sink-minus-source price differences, with negative differences resulting in a liability for the holder. Based on the annual and monthly FTR auction revenue, ARR holders are granted credits that can range from zero to the target allocations. ARR holders receiving credits equal to the target allocations are deemed fully funded.

ARRs have been available to eligible participants[10] since June 1, 2003, when the Annual ARR Allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the PJM Mid-Atlantic Region and the AP Control Zone, while the 2004 to 2005 planning period's allocation covered the PJM Mid-Atlantic Region and the AP and ComEd Control Zones. Eligible participants in the AEP and DAY Control Zones received phase-in, direct allocation FTRs instead of ARRs upon their integration into PJM on October 1, 2004.

Market Structure

Supply and Demand

Since ARRs are financial instruments allocated annually to network and long-term, firm point-to-point transmission customers, the maximum ARR demand equals the subscribed amount of such services. On June 1, 2004, PJM provided 85,233 MW of network and 3,713 MW of firm point-to-point service. Therefore, maximum demand for ARRs would be 88,946 MW, the sum of network and long-term, firm point-to-point transmission service.

10 See generally "PJM Operating Agreement Accounting Manual" (May 01, 2004) <http://www.pjm.com/contributions/pjm-manuals/pdf/m28v27.pdf> (306 KB); and "PJM Financial Transmission Rights Manual" (December 07, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m06v06.pdf> (207 KB).

ARR demand was 55,128 MW during the 2004 to 2005 planning period, up from 39,888 MW during the 2003 to 2004 planning period. ARR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested ARRs, and numerous combinations of ARRs are feasible. For the set of requested ARRs, available supply was 33,589 MW. This level of ARR availability was higher than the 28,933 MW available during the 2003 to 2004 planning period, but still left 21,539 MW of ARR demand unfulfilled. The Bedington-Black Oak interface and the Eastern Interface were the principal constraints limiting supply, followed by Byron-Cherry Valley 345 and Cedar Grove-Clifton 230.

ARR Allocation

Firm point-to-point and network service transmission customers[11] can request ARRs in quantities ranging from zero to a MW amount consistent with their transmission service.

PJM allocates annual ARRs to eligible customers in a two-stage process:

- **Stage 1.** Network transmission customers can obtain ARRs to their load from generation resources that historically have served load in the zone or load aggregate where the network transmission customer's load is located. ARRs were not available to firm point-to-point transmission customers in Stage 1.[12]

- **Stage 2.** Network transmission customers can obtain ARRs from any generator, hub, zone or interface to any part of their zonal load without an allocated ARR. Firm point-to-point customers can obtain ARRs consistent with their transmission service. There are four rounds, and 25 percent of remaining system capability is allocated in each round.

If the requested set of ARRs is not simultaneously feasible,[13] customers are allocated pro rata shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints as follows:

> Individual *pro rata* MW = (Constraint capability) * (Individual requested MW / Total requested MW) * (1 / per MW effect on line)[14]

External capacity resources must have a confirmed transmission service request in OASIS prior to the annual ARR allocation. If firm transmission service is used to deliver external capacity into PJM and the capacity resource is located in a control zone that joins PJM, the firm point-to-point transmission service may be converted to network service after control zone integration.

Market participants constructing transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall system simultaneous feasibility can be maintained.

11 Network service transmission customers have reliability obligations to supply load at one or more points on the system and must obtain capacity plus reserves from qualified capacity resources. Firm point-to-point transmission customers have reserved transmission capability between two points that is usually used to deliver resources into or out of the RTO. Both types of customers are referred to as eligible customers in this section.
12 PJM has proposed that certain point-to-point customers should be allowed to participate in this stage, placing them on equal footing with network service transmission customers.
13 The simultaneous feasibility test (SFT) ensures that the approved set of ARRs can be supported by the transmission system and is meant to ensure ARR revenue adequacy.
14 See Appendix G, "Financial Transmission Rights and Auction Revenue Rights" for an illustration explaining this calculation in greater detail.

ARRs associated with shorter term, firm transmission service can be requested within the planning period through the PJM Open Access Same-Time Information System (OASIS).

ARR Reassignment for Retail Load Switching

Current PJM rules ensure that when load switches among LSEs during the planning period, a proportional share of associated ARRs within a given transmission or load aggregation zone is automatically reassigned to follow that load.[15] ARR reassignment occurs only if the LSE losing load has ARRs with net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. This rule supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs.

Table 7-1 - ARRs automatically reassigned for network load changes by control zone (MW-day): June 1, 2003, to December 31, 2004

	AECO	BGE	DPL	JCPL	PECO	PENELEC	PEPCO	PPL	PSEG	RECO	Met-Ed	AEP	AP	ComEd	DAY	Total
Jun-03	3	25	7	0	25	34	26	11	0	0	40	0	0	0	0	171
Jul-03	2	30	3	15	43	0	2	2	9	0	0	0	127	0	0	233
Aug-03	1,592	5	0	2,801	35	0	281	0	3,411	324	1	0	0	0	0	8,450
Sep-03	17	2	24	70	25	0	162	6	242	0	0	0	0	0	0	548
Oct-03	16	2	125	63	16	0	4	6	144	0	0	0	0	0	0	376
Nov-03	24	19	13	99	11	0	2	12	180	0	7	0	0	0	0	367
Dec-03	15	4	10	33	475	4	2	14	123	0	1	0	0	0	0	681
Jan-04	10	1	53	31	230	0	257	13	120	0	20	0	0	0	0	733
Feb-04	2	7	1	17	18	4	136	121	52	0	0	0	28	0	0	385
Mar-04	31	12	1	9	14	0	139	1	41	0	14	0	0	0	0	261
Apr-04	3	10	2	43	14	1	5	8	20	0	51	0	0	0	0	158
May-04	7	206	44	82	330	1	3	46	148	0	6	0	0	5,175	0	6,047
Jun-04	54	275	104	517	172	20	580	58	295	0	65	0	6	1,033	0	3,177
Jul-04	52	2,644	2,255	45	14	0	3,063	1	77	0	3	0	0	308	0	8,460
Aug-04	2	64	10	31	13	0	138	1	105	0	0	0	0	269	0	633
Sep-04	2	225	17	14	14	0	122	10	78	3	0	0	0	68	0	551
Oct-04	0	233	15	0	9	0	407	1	38	0	0	16	13	66	3	800
Nov-04	3	60	6	0	14	0	24	7	29	0	0	3	0	34	0	180
Dec-04	4	317	10	0	376	0	882	3	76	5	0	16	1	89	0	1,778
Total	1,837	4,140	2,699	3,868	1,848	64	6,234	318	5,185	332	207	36	174	7,042	3	33,986

Table 7-1 and Table 7-2 summarize ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2003 and December 2004. Nearly 34,000 MW of ARRs were automatically reassigned, generating more than $40 million of revenue for LSEs receiving ARRs during the 19-month period, or $264,300 per MW-day of revenue associated with. Most automatic reassignment of ARRs was associated

15 See PJM manual, "Financial Transmission Rights (m06), Revision 6" (December 07, 2004) <http://www.pjm.com/contributions/pjm-manuals/pdf/m06v06.pdf> (207 KB).

with state-mandated programs. As an example, in New Jersey, 8,127 MW of ARRs were automatically reassigned for its Basic Generation Service Program during August 2003.[16] Similarly, in Maryland, 7,962 MW of ARRs were automatically reassigned for its Standard Offer Service Program during July 2004.[17]

Table 7-2 - ARR revenue automatically reassigned for network load changes by control zone (Thousands of dollars per MW-day): June 1, 2003, to December 31, 2004

	AECO	BGE	DPL	JCPL	PECO	PENELEC	PEPCO	PPL	PSEG	RECO	Met-Ed	AEP	AP	ComEd	DAY	Total
Jun-03	$0.0	$0.4	$0.0	$0.0	$0.3	$1.2	$0.8	$0.0	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$3.0
Jul-03	$0.0	$0.2	$0.0	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8
Aug-03	$12.5	$0.1	$0.0	$0.0	$0.5	$0.0	$5.0	$0.0	$45.2	$2.3	$0.0	$0.0	$0.0	$0.0	$0.0	$65.6
Sep-03	$0.2	$0.0	$0.5	$0.0	$0.4	$0.0	$2.7	$0.0	$3.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$7.0
Oct-03	$0.2	$0.0	$2.5	$0.0	$0.2	$0.0	$0.1	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.0
Nov-03	$0.3	$0.3	$0.3	$0.0	$0.2	$0.0	$0.0	$0.1	$2.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.6
Dec-03	$0.2	$0.1	$0.2	$0.0	$7.2	$0.1	$0.0	$0.1	$1.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$9.6
Jan-04	$0.1	$0.0	$0.9	$0.0	$2.7	$0.0	$4.7	$0.1	$1.6	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$10.5
Feb-04	$0.0	$0.1	$0.0	$0.0	$0.3	$0.1	$2.5	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.4
Mar-04	$0.4	$0.2	$0.0	$0.0	$0.2	$0.0	$3.3	$0.0	$0.6	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$4.9
Apr-04	$0.0	$0.2	$0.1	$0.1	$0.2	$0.0	$0.1	$0.1	$0.3	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$1.3
May-04	$0.1	$3.8	$0.9	$0.0	$6.5	$0.0	$0.1	$0.5	$2.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$13.9
Jun-04	$1.3	$2.3	$1.0	$7.3	$3.6	$0.5	$1.8	$0.2	$8.1	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$26.8
Jul-04	$1.4	$25.7	$32.2	$0.8	$0.2	$0.0	$11.2	$0.0	$2.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$73.5
Aug-04	$0.0	$0.6	$0.1	$0.5	$0.2	$0.0	$0.5	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.6
Sep-04	$0.0	$2.2	$0.2	$0.2	$0.3	$0.0	$0.4	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.5
Oct-04	$0.0	$2.3	$0.2	$0.0	$0.1	$0.0	$1.3	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.9
Nov-04	$0.1	$0.6	$0.1	$0.0	$0.1	$0.0	$0.1	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.8
Dec-04	$0.1	$2.7	$0.1	$0.0	$8.3	$0.0	$4.0	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$17.4
Total	$16.9	$41.8	$39.3	$9.0	$32.2	$1.8	$38.6	$2.0	$78.5	$2.3	$2.0	$0.0	$0.0	$0.0	$0.0	$264.3

ARRs and Integrations

Phase-In FTRs

During any planning period when new control zones are being integrated, PJM directly allocates phase-in FTRs to eligible customers in those zones. These FTRs remain in effect until the start of the next planning period. These customers can elect to receive either annual ARRs or direct allocation FTRs at the start of the first two full planning periods of their PJM membership, but do not retain the direct allocation, FTR option after the two-year transition period. Table 7-3 summarizes the availability of ARRs and direct allocation FTRs.

16 N.J.S.A. 48:3-57 (2004).
17 Md. PUBLIC UTILITY COMPANIES Code Ann § 7-510 (2003)..

Table 7-3 - ARRs vs. directly allocated FTRs: Eligibility

Region/Zone	ARRs	Direct Allocation FTRs
Mid-Atlantic	Yes	No
AP	Yes	Through 2004/2005 planning period
ComEd	Yes	Through 2005/2006 planning period
AEP and DAY	Yes	Through 2006/2007 planning period

Eligible customers in the PJM Mid-Atlantic Region had the option to receive annual ARRs for the 2004 to 2005 planning year, while eligible customers in the AP and ComEd Control Zones had the option to choose either ARRs or direct allocation FTRs. On their October 1, 2004, integration date, eligible customers in the AEP and DAY Control Zones received phase-in, direct allocation FTRs effective through the end of the planning period.

Congestion Mitigation Credits

In a January 28, 2004, order, the FERC responded to protests concerning PJM Tariff provisions for allocating FTRs and ARRs to customers in newly integrated control zones. The FERC required that the PJM Tariff be amended to create a new allocation methodology so that customers in the new zones could raise and the FERC could resolve any concerns about the initial allocations before the integrations. The FERC order stated:

> We find that under the procedures set forth in PJM's tariff, there is some uncertainty as to the exact level of ARRs that a customer in an area joining PJM will receive. To provide customers in new areas with an opportunity to raise any specific concerns with their ARR allocation before it is implemented, we will require PJM to make a further compliance filing with the Commission. Specifically, we will require PJM to amend section 5.2.2(e) of its tariff to state that PJM, prior to the initial allocation of FTRs in new regions, will make a filing with the Commission under section 205 of the Federal Power Act with the proposed allocation of ARRs.[18]

In its subsequent May 28, 2004, order, the FERC added:

> Because the allocation process provides preference to network service customers, the Commission finds that PJM's annual allocation process for FTRs and ARRs under its existing Tariff and Operating Agreement appears to be unjust and unreasonable under section 206 of the Federal Power Act, and the Commission is instituting procedures to determine a just and reasonable allocation process for succeeding years.[19]

In responding, PJM acknowledged that the two-stage allocation process included a preference for native load customers served from resources that had historically served their load. PJM explained that the two-stage process resulted from a "compromise" in PJM's Market Implementation Committee designed to "give native load customers a priority in requesting ARRs from resources that historically served the load in the transmission zone," and to provide ample flexibility for market participants to pursue hedging strategies consistent with their changing needs in the second stage.[20]

18 106 FERC ¶ 61,049 (2004).
19 107 FERC ¶ 61,223 (2004) "Order Conditionally Accepting June Annual Allocation for Commonwealth Edison Zone," Docket No. ER04-742-000.
20 107 FERC ¶ 61,223 (2004) "Order Conditionally Accepting June Annual Allocation for Commonwealth Edison Zone," Docket No. ER04-742-000.

FERC ordered that if long-term, firm point-to-point transmission customers in the ComEd and AEP Control Zones were not allocated their full request for ARRs or FTRs that they be provided with congestion mitigation outside of the FTR and ARR markets. PJM implemented this order by offering mitigation credits equal to FTR payments to those eligible customers that had not received their requested allocation.

Total mitigation credit costs are assessed as uplift charges. All firm network and point-to-point transmission service customers with ARRs, FTRs or congestion mitigation credits within the ComEd and AEP Control Zones pay these zonal uplift charges.

For the portions of the 2004 to 2005 planning period remaining after their Phase 2 and Phase 3 integration, Table 7-4 summarizes FTRs requested by and awarded to customers in the relevant control zones, including mitigation FTRs.

Table 7-4 - ComEd and AEP Control Zones FTR mitigation credits: Planning period 2004 to 2005

Zone	Period	FTR Requests (MW)	FTR Awarded (MW)	Mitigation (MW)	Mitigation Percent
ComEd	May-04	888	440	448	50%
ComEd	Jun-Sep-04	1,431	864	567	40%
ComEd	Oct-04-May-05	476	308	168	35%
AEP	Oct-04-May-05	1,005	51	954	95%
Total		**3,800**	**1,662**	**2,138**	**56%**

ARR Performance

Volume

Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW (61 percent) were allocated. Eligible market participants subsequently converted 13,061 MW of these allocated ARRs into annual FTRs (39 percent), leaving 20,528 MW of ARRs outstanding. During the 2003 to 2004 planning period, supply had been 28,933 MW for the set of ARRs requested, leaving 10,955 MW of demand unfulfilled. Eligible market participants subsequently converted 13,986 MW of ARRs into annual FTRs, leaving 14,947 MW of ARRs outstanding.

Revenue

An ARR credit received equals the product of the ARR MW and the sink-minus-source price difference from the Annual FTR Auction. The degree to which ARR credits provide a complete congestion hedge is determined by the prices that result from the Annual FTR Auction. The prices that result from the Annual FTR Auction are the result of bids based on participants' expectations about the level of congestion in the Day-Ahead Energy Market. The resultant ARR credit could be greater than, less than or equal to the actual congestion that occurs on the selected path in the Day-Ahead Energy Market and thus could provide a hedge with varying levels of completeness.

Eligible customers can also opt to retain the underlying FTRs linked to their ARRs through a process termed self-scheduling. The underlying FTR[21] has a hedge value based on actual day-ahead congestion on the selected path instead of on what bidders are willing to pay in the Annual FTR Auction based on their expectations of day-ahead congestion on the selected path.

ARR holders will receive $345 million in credits from the Annual FTR Auction during the 2004 to 2005 planning period, with an average hourly ARR credit of $1.17 per MWh. During the comparable 2003 to 2004 planning period, ARR holders received $311 million in ARR credits, with an average hourly ARR credit of $1.23 per MWh.

Revenue Adequacy

An ARR target allocation defines revenue that an ARR holder should receive and is equal to the product of ARR MW and the ARR sink-to-source price differences established during the Annual FTR Auction. FTR auction revenue is the net revenue it generates and equals the sum of the products of FTR MW and FTR sink-to-source price differences. All ARRs receive ARR credits equal to their target allocations and would be fully funded if total annual FTR auction revenue were greater than or equal to the sum of all ARR target allocations. If total annual FTR auction revenue were less than that, however, the available revenue would be proportionally allocated among all ARR holders and revenue from the Monthly FTR Auctions would be used to make up any ARR target allocation deficiencies.

Table 7-5 lists ARR target allocations and revenue sources earmarked to ARRs. Net annual FTR auction revenue has been sufficient to cover ARR target allocations, providing ARR revenue adequacy during both the 2003 to 2004 and the 2004 to 2005 planning periods. The 2004 to 2005 planning period's Annual and Monthly FTR Auctions generated a surplus of $34 million in auction revenue through year-end, above the amount needed to pay ARRs 100 percent of their target allocations. These surplus funds are used to fund FTR target allocation deficiencies in the Day-Ahead Energy Market.

Table 7-5 - ARR revenue adequacy [Dollars (million)]: By planning period

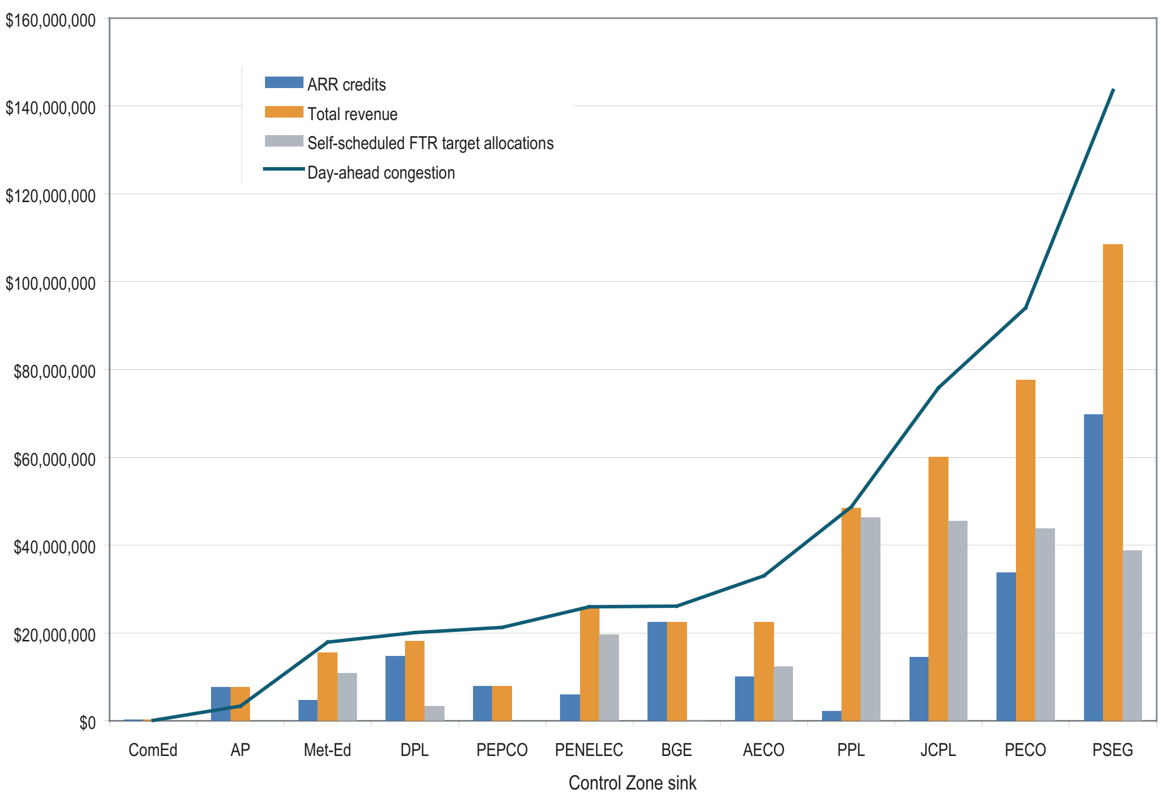
Item	2003/2004	2004/2005
Total FTR Auction Revenue	$358	$379
Annual FTR Auction Net Revenue	$333	$370
Monthly FTR Auction Net Revenue*	$26	$10
ARR Target Allocations	$311	$345
ARR Credits	$311	$345
Surplus Auction Revenue	$48	$34
ARR Payout Ratio	**100%**	**100%**
* Through December 31, 2004		

21 FTR value is determined each hour in the Day-Ahead Energy Market and equals the product of the FTR sink-minus-source Day-Ahead Energy Market price difference and the FTR MW.

ARR Revenue versus Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison between the revenue received by holders of the allocated ARRs and the congestion across the corresponding paths. This comparison is presented in Figure 7-1. Revenue received includes ARR revenue (the blue bars), the revenue from ARRs self-scheduled as FTRs (the gray bars) and the sum of these revenues (the orange bars). The line shows the amount of congestion incurred in the Day-Ahead Energy Market across the corresponding ARR and self-scheduled FTR paths. Data shown are for the first seven months of the 2004 to 2005 planning period and summed by ARR control zone sink. For example, the figure shows that between June 1, 2004, and December 31, 2004, ARRs allocated to JCPL Control Zone load received a total of $61 million in revenue, $15 million in ARR and $46 million in self-scheduled FTR credits, against $76 million in day-ahead congestion.

Figure 7-1 - ARR and self-scheduled FTR congestion hedging by control zone: Planning period 2004 to 2005 through December 31, 2004

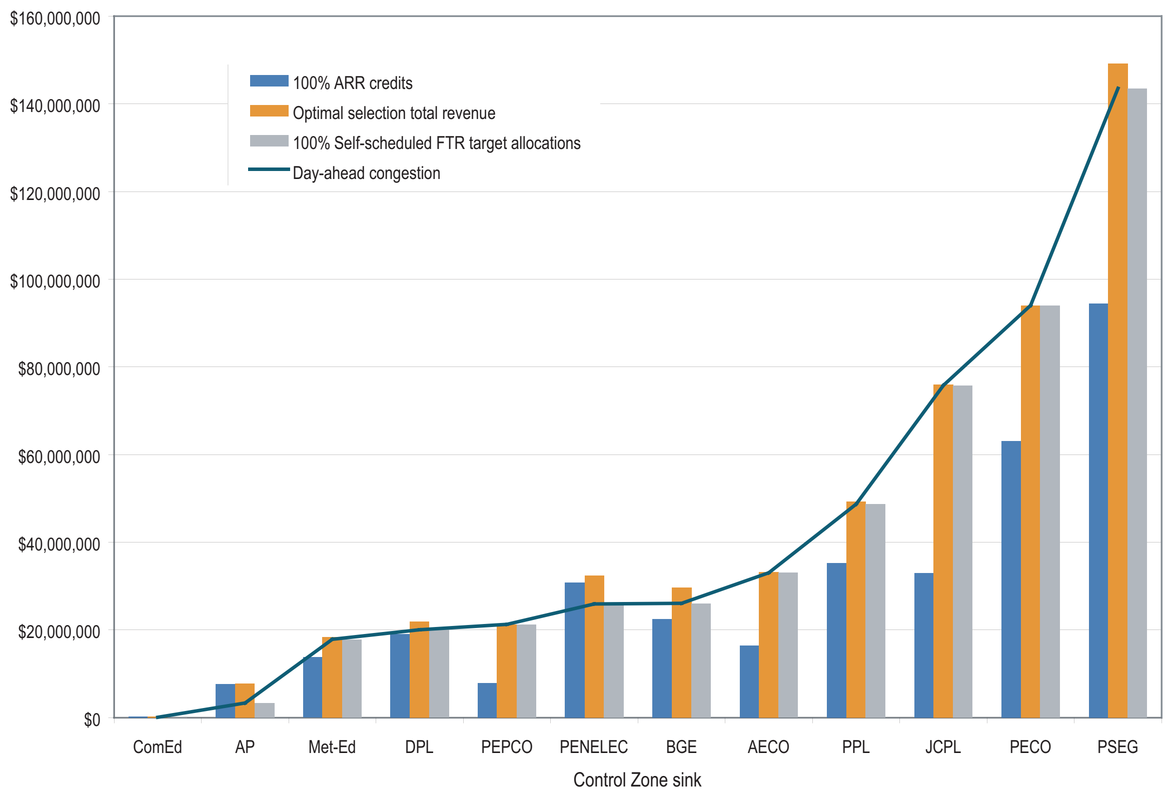


During the first seven months of the 2004 to 2005 planning period, congestion costs across the 33,589 MW of allocated ARRs were $510 million. These costs are calculated as the product of the ARR MW and the hourly day-ahead ARR sink and source LMP differences. As has been indicated, 13,061 MW of ARRs were converted into FTRs through the self-scheduling option, with 20,582 MW remaining as ARRs. ARRs that were not self-scheduled provided $194 million of ARR credits, representing a hedge of 38 percent of the $510 million in congestion costs incurred, while the self-scheduled FTRs provided $221 million of revenue, hedging an additional 43 percent of congestion costs. Total congestion hedged by both was $415 million, or 81 percent, down from 89 percent during the 2003 to 2004 planning period.

Figure 7-1 shows that load in four of 12 transmission zones, ComEd, AP, PENELEC and PPL, was fully hedged by the selected combination of ARRs and self-scheduled FTRs. The ComEd Control Zone actually experienced negative congestion and would have been fully hedged without ARRs or FTRs. ARRs into the PEPCO, PSEG, PECO, JCPL and AECO Control Zones accounted for $91 million of unhedged congestion, out of a total unhedged congestion of $95 million. Two of these, JCPL and PSEG, were the zones most affected by the Branchburg transformer derating. Nonetheless, ARRs into the PSEG Control Zone provided a hedge of 76 percent, up from 60 percent during the 2003 to 2004 planning period.

To evaluate the consequences of actual ARR and self-scheduled FTR choices, three possible hedging strategies were compared. Figure 7-2 illustrates the results for the first seven months of the 2004 to 2005 planning period.

Figure 7-2 - Optimal ARR and self-scheduled FTR portfolio congestion hedging by control zone: Planning period 2004 to 2005 through December 31, 2004



The first hedging strategy would take all allocated ARRs without any self-scheduling of FTRs. The second hedging strategy would convert all allocated ARRs into FTRs, an approach that would hedge all congestion less any FTR funding deficiencies. If ARR holders had held all their ARRs, shown in Figure 7-2 as the blue bars, they would have received $345 million of ARR credits against $510 million of congestion, a 68 percent hedge. If ARR holders had converted all their ARRs to FTRs, shown as the gray bars, they would have received $510 million of ARR credits against $510 million of congestion, a 100 percent hedge. Figure 7-2 shows that the selected ARRs would have been more valuable converted to FTRs for all but three control zones (ComEd, AP, PENELEC), while in these zones ARRs would have provided a better hedge.

The third hedging strategy (a hypothetical strategy) would retain those ARRs more valuable as ARRs and convert those more valuable as FTRs into FTRs, thereby achieving an optimal combination of ARRs and self-scheduled FTRs. The analysis represents the maximum achievable hedge based on an after-the-fact evaluation.

For the first seven months of the 2004 to 2005 planning period (i.e., June to December 2004), this hypothetical combination of ARRs and self-scheduled FTRs, shown as the orange bars, would have netted $534 million, covering 105 percent of the $510 million congestion across the ARRs and leaving a surplus of $23 million. For the 2003 to 2004 planning period, the optimally selected combination of ARRs and self-scheduled FTRs would have netted $234 million, covering 117 percent of the $199 million in congestion across the ARRs and leaving a surplus of $35 million.

The analysis demonstrates that while the hypothetical mix of ARRs and self-scheduled FTRs always returns the most revenue, customers in most control zones could have obtained nearly the maximum possible revenue by selecting the all self-scheduled FTR strategy, although for some control zones ARRs are more valuable than FTRs.

Financial Transmission Rights

Although FTRs have been available to eligible participants since the 1998 introduction of LMPs, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. For the 2004 to 2005 planning period, the auction covered the PJM Mid-Atlantic Region and the AP and ComEd Control Zones. Eligible participants in the AEP and DAY Control Zones received phase-in, direct allocation FTRs upon their integration into PJM on October 1, 2004.

FTRs are financial instruments that entitle their holders to receive revenue based on prices in the Day-Ahead Energy Market. The FTR target allocation (i.e., what the FTR holder should receive) is equal to the product of the FTR MW and the sink-minus-source price differences that occur in the hourly Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on these sink-minus-source price differences, with negative differences resulting in a liability for the holder. Depending on the congestion charges collected, FTR holders receive congestion credits between zero and their target allocations. When FTR holders receive their target allocation the associated FTRs are termed fully funded.

There are two different FTR hedge types. An FTR obligation provides a credit, positive or negative, equal to the product of the FTR MW and the sink-to-source price difference that occurs in the hourly Day-Ahead Energy Market. An FTR option provides only positive credits. As FTR options require that feasibility exist in the SFT both with and without them, FTR options are priced higher than FTR obligations.

There are three standard FTR obligation and option products: 24-hour, on-peak and off-peak FTRs. The 24-hour FTRs are effective 24 hours a day, seven days a week, while on-peak FTRs are effective only during on-peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Monday through Friday, excluding NERC holidays. Off-peak FTRs are in effect during all other periods.

Market Structure

Before the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to obtain annual FTRs. Now all qualified market participants can participate in the Annual FTR Auction. In addition, auction market participants are free to request long-term FTRs between any pricing nodes on the system, not just from designated capacity resources to network load or solely along a long-term, firm, point-to-point transmission service path. As a result, total demand for FTRs has expanded.

Supply and Demand

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the option to obtain underlying FTRs in place of allocated ARRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs, and numerous combinations of FTRs are feasible. FTRs can also be obtained in the Monthly FTR Auctions, as direct allocation FTRs (available to customers in recently integrated control zones) and via bilateral trades of existing FTRs.

Table 7-6 shows that 177,434 MW of annual FTR bids and allocation requests were cleared and allocated in the Annual FTR Auction and allocations for the 2004 to 2005 planning period: 93,344 MW in the Mid-Atlantic Region, 46,722 MW in the ComEd Control Zone, 28,495 MW in the AEP and DAY Control Zones combined and 8,874 MW in the AP Control Zone. A total of 974,934 MW were bid, offered, or requested to be allocated.

Table 7-8 shows just the Annual FTR Auction data. (Table 7-6 shows both Annual Auction data and annual allocation requests.) As shown, 119,629 MW of annual FTRs were purchased in Annual FTR Auctions for the 2004 to 2005 planning period: 93,344 MW in the Mid-Atlantic Region and 26,285 in the ComEd Control Zone. A total of 861,323 MW were bid and a total of 50,780 MW were offered. By comparison, for the 2003 to 2004 planning period, a total of 80,928 MW of annual FTRs were transacted in the Mid-Atlantic Region.

Table 7-6 - Annual FTR market volume: Planning period 2004 to 2005

Region/Zone	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)
Buy Activity			
AEP/DAY	1,283	29,582	28,495
AP	102	8,874	8,874
ComEd	6,154	257,842	46,722
Mid-Atlantic	58,200	627,856	93,344
Total	65,739	924,154	177,434
Sale Activity			
AEP/DAY	N/A	N/A	N/A
AP	N/A	N/A	N/A
ComEd	376	6,283	1,344
Mid-Atlantic	8,943	44,497	5,170
Total	9,319	50,780	6,514

During any planning period when new control zones are being integrated, PJM directly allocates phase-in FTRs to eligible customers in those control zones. These FTRs remain in effect until the start of the next planning period. These customers can elect to receive either annual ARRs or direct allocation FTRs at the start of the first two full planning periods of their PJM membership, but no longer have the direct allocation FTR option after the two-year transition period. Table 7-3 summarizes the availability of ARRs and direct allocation FTRs within the different regions and control zones.

Each March, PJM conducts an Annual FTR Auction during which all eligible market participants can bid on the next planning period's FTRs consistent with total transmission system capability. The auction takes place over four rounds as follows:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on-peak or off-peak FTR obligations or FTR options. Locational prices are determined by maximizing the offer-based value of FTRs cleared.[22] Auction participation is not restricted to any class of customers, and any market participant can make offers for available FTRs. ARR holders wishing to self-schedule their previously allocated ARRs as FTRs must initiate the self-scheduling process in this round. One-quarter of each self-scheduled FTR clears as a 24-hour FTR in this and each of the subsequent three rounds. Self-scheduled FTRs must have the same source and sink as the ARR. No bid price is associated with self-scheduled FTRs. Such self-scheduled FTRs clear as price-taking FTR obligations.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

22 Both Annual and Monthly FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the maximum amount of net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

By self-scheduling ARRs as price-taking buy-bids in the Annual FTR Auction, customers with ARRs receive FTRs along their ARR path. ARR holders are guaranteed that they will receive their requested FTRs and such self-scheduled bids will be ineligible to set auction price. ARRs may be self scheduled only as 24-hour FTRs. ARR holders that self-schedule ARRs as FTRs still hold the associated ARR. Self-scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the corresponding ARR and is left with ownership of the FTR as a hedge.

PJM also conducts Monthly FTR Auctions during which market participants can bid on monthly FTRs consistent with residual transmission system capability for the following month. These are single-round auctions in which market participants make offers for FTRs and FTR holders can offer monthly segments of their FTRs.

FTRs can also be obtained in two other ways. Eligible participants can trade them through the PJM-administered, bilateral market or market participants can trade them among themselves without PJM involvement.

As Table 7-6 shows, Annual FTR demand in PJM was 924,154 MW during the 2004 to 2005 planning period. At the more local regional or zonal levels, the 2004 to 2005 planning period demand was 627,856 MW in the Mid-Atlantic Region, 257,842 MW in the ComEd Control Zone, 29,582 MW in the combined AEP and DAY Control Zones and 8,874 MW in the AP Control Zone.

One result of operating an FTR Auction with unlimited participation is that participants may put in unlimited demands based on a variety of financial strategies. This is in contrast to the situation prior to the FTR Auction when demand for FTRs was limited to the loads of firm transmission customers. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs, and numerous combinations of FTRs are feasible. For the requested FTRs for the 2004 to 2005 planning period, supply met demand at 177,434 MW, leaving 746,720 MW of demand unfulfilled. Supply was 93,344 MW in the Mid-Atlantic Region, leaving 534,513 MW of demand unfulfilled. Demand exceeded supply by 211,120 MW in the ComEd Control Zone and by 1,087 MW in the combined AEP and DAY Control Zones. Supply equaled demand in the AP Control Zone. Table 7-7 lists the principal constraints that precluded awarding all FTRs requested.

Table 7-7 - Annual FTR Auction and allocation principal binding transmission constraints: Planning period 2004 to 2005

Region/Zone	Principal Constraints
AEP/DAY	Kanawha River-Matt Funk 345 kV
AP	None
Mid-Atlantic	Branchburg transformer (derated), Bedington-Black Oak Interface, and Wylie Ridge transformer
ComEd	Stations 15518 138 kV and 11414 138 kV

Annual FTR holders offered an average of 2,960 MW of FTRs per month in the Monthly FTR Auctions, while demand averaged 18,246 MW per month.

In addition to the Annual and Monthly FTR Auctions, FTRs can be traded between market participants through bilateral transactions. Bilateral activity was consistent with previous years, with 1,433 MW of FTRs traded in calendar year 2004, as compared to 1,352 MW in calendar year 2003 and 7,173 MW in calendar year 2002.

Market Performance

Volume

For the entire PJM footprint, for the 2004 to 2005 planning period, 177,434 MW of annual FTRs were purchased and allocated out of 924,154 MW bid and requested. (See Table 7-6.) For the Mid-Atlantic Region, 93,344 MW were purchased and allocated out of 627,856 MW bid and requested. For the ComEd Control Zone, 46,722 MW were purchased and allocated out of 257,842 MW bid and requested. For the AEP and DAY Control Zones combined, 28,495 MW were purchased and allocated out of 29,582 MW bid and requested. Finally, for the AP Control Zone, 8,874 MW were purchased and allocated out of 8,874 MW bid and requested. (See Table 7-6.) Eligible market participants converted 13,061 MW of Mid-Atlantic Region ARRs into annual FTRs. In comparison, during the 2003 to 2004 planning period, 86,767 MW were purchased and allocated, with 80,928 MW purchased and allocated in the Mid-Atlantic Region and 5,839 MW purchased and allocated in the AP Control Zone. For the 2003 to 2004 planning period, eligible market participants converted 13,986 MW of Mid-Atlantic Region ARRs into annual FTRs.

In the ComEd Control Area and AP Control Zone where participants had a choice between ARRs and direct allocation FTRs, they opted for significantly more direct allocation FTRs than ARRs, with a total of 33,249 MW in direct allocation FTRs compared to 363 MW in ARRs.

Revenue

Table 7-8 shows Annual FTR Auction summary data. During the 2004 to 2005 planning period, the Annual FTR Auctions for the ComEd Control Zone and the Mid-Atlantic Region netted $369.6 million in revenue, with buyers paying $380.0 million and sellers receiving $10.4 million. By contrast, for the 2003 to 2004 planning period, the Mid-Atlantic Region Annual FTR Auction had netted $332.8 million in revenue, with buyers paying $345.8 million and sellers receiving $13.0 million. As Table 7-5 shows, ARR holders received $345 million in FTR auction revenue.

Table 7-8 - Annual FTR Auction market volume, price and revenue: Planning period 2004 to 2005

Region/Zone	Bids	Bid MW	Cleared MW	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue ($)
Net Activity						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	N/A	N/A	N/A	N/A	N/A	$7,964,048
Mid-Atlantic	N/A	N/A	N/A	N/A	N/A	$361,634,985
Total	N/A	N/A	N/A	N/A	N/A	$369,599,033
Buy Bids						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	5,675	233,467	26,285	$0.02	$0.06	$10,888,800
Mid-Atlantic	58,200	627,856	93,344	$0.14	$0.60	$369,061,658
Total	59,903	861,323	119,629	$0.11	$0.48	$379,950,458
Sale Offers						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	376	6,283	1,344	$1.78	$0.33	($2,924,752)
Mid-Atlantic	8,943	44,497	5,170	$0.05	$0.22	($7,426,673)
Total	9,319	50,780	6,514	$0.26	$0.24	($10,351,425)

23 As some FTRs are bid with negative prices, some winning FTR bidders are actually paid to take FTRs. These payments reduce the amount of net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

Figure 7-3 summarizes the total revenue associated with all FTRs regardless of source to the 10 FTR sinks (destinations) that produced the most Annual FTR Auction revenue. FTRs to these sinks accounted for $390.4 million or about 103 percent of all revenue paid[23] and constituted 39 percent of all FTRs bought in Annual FTR Auctions for the 2004 to 2005 planning period. These sinks include the control zones and hubs of the Mid-Atlantic Region.

Figure 7-3 - Highest revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2004 to 2005

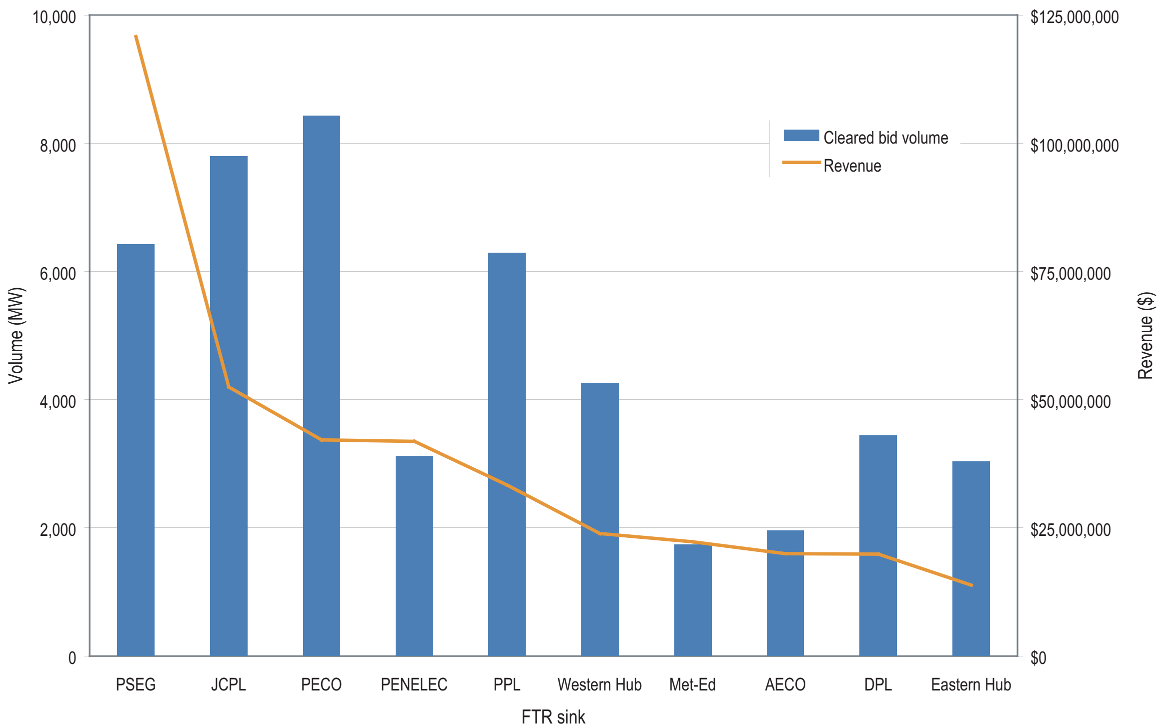


Figure 7-4 summarizes the total revenue associated with all FTRs regardless of sink from the 10 FTR sources (origins) that produced the most Annual FTR Auction revenue for the 2004 to 2005 planning period. FTRs from these sources accounted for $187 million or about 49 percent of all revenue paid and included 17 percent of all FTRs bought in Annual FTR Auctions. These sources are generally located at large generating facilities throughout the Mid-Atlantic Region.

Figure 7-4 - Highest revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2004 to 2005

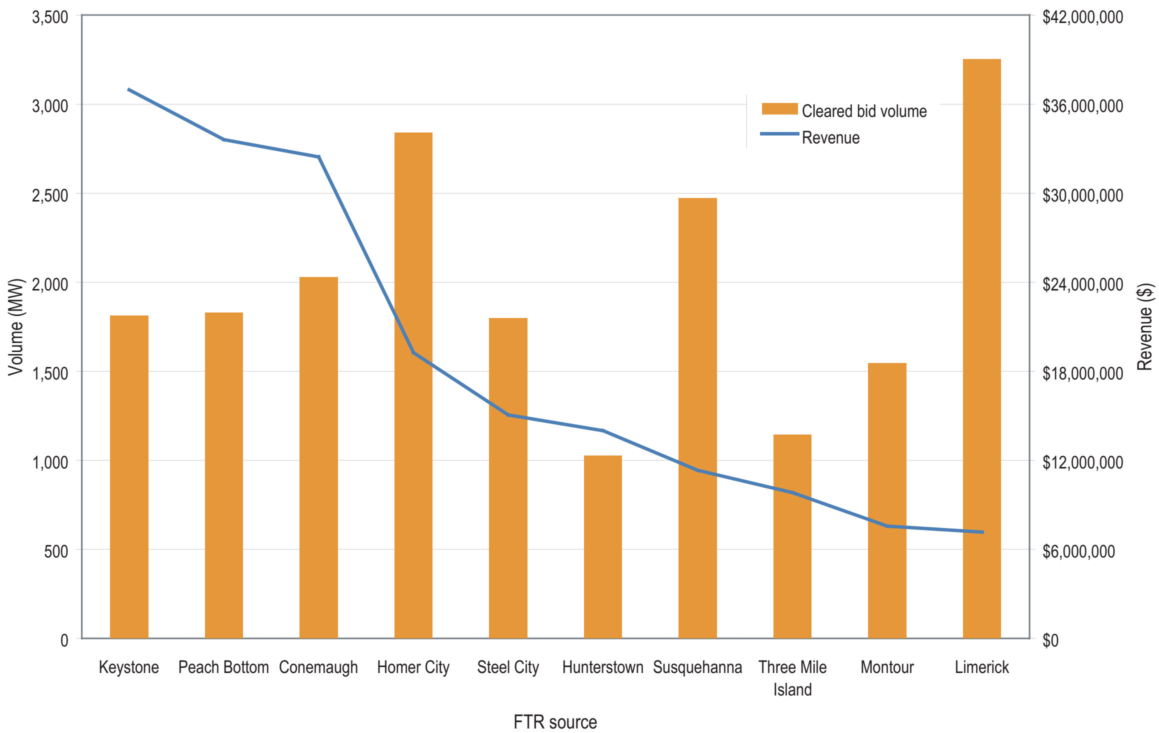


Figure 7-5 summarizes the total revenue associated with all FTRs regardless of source to the 10 FTR sinks that produced the most monthly FTR auction revenue during the period June 2003 through December 2004. FTRs to these sinks accounted for $49 million, or about 13 percent of all revenue paid and included 12 percent of all FTRs bought in Monthly FTR Auctions. The sinks tended to be located in the Mid-Atlantic Region or the AP Control Zone.

Figure 7-5 - Highest revenue producing FTR sinks purchased in the Monthly FTR Auctions: June 2003 to December 2004

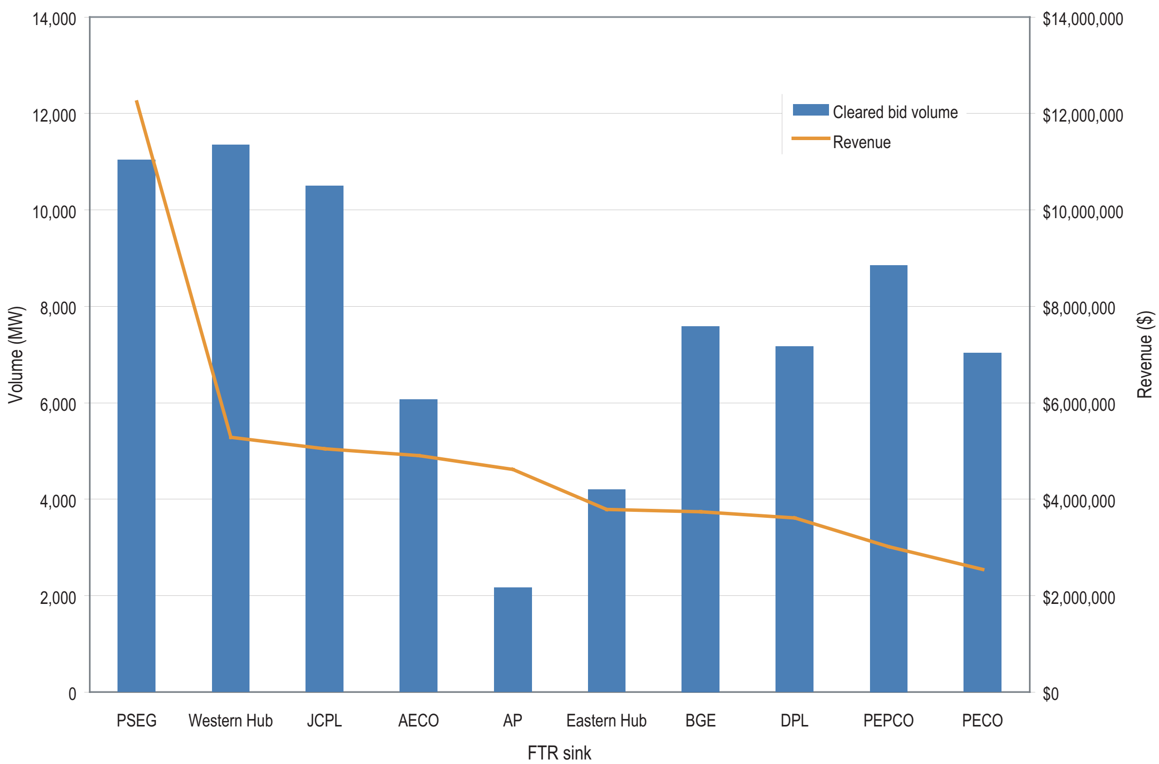


Figure 7-6 summarizes the total revenue associated with all FTRs regardless of sink from the 10 FTR sources that produced the most monthly FTR auction revenue during the period June 2003 through December 2004. FTRs from these sources accounted for $46 million, or about 12 percent of all revenue paid and included 12 percent of all FTRs bought in Monthly FTR Auctions.

Figure 7-6 - Highest revenue producing FTR sources purchased in Monthly FTR Auctions: June 2003 to December 2004

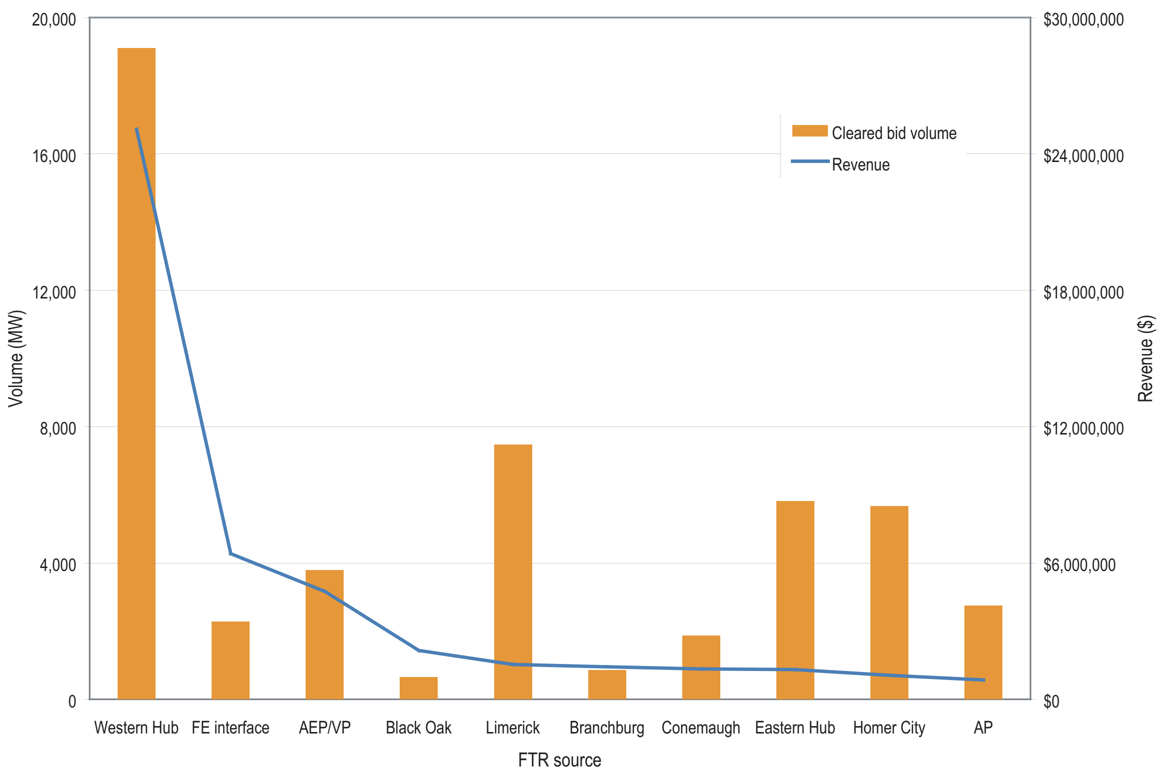
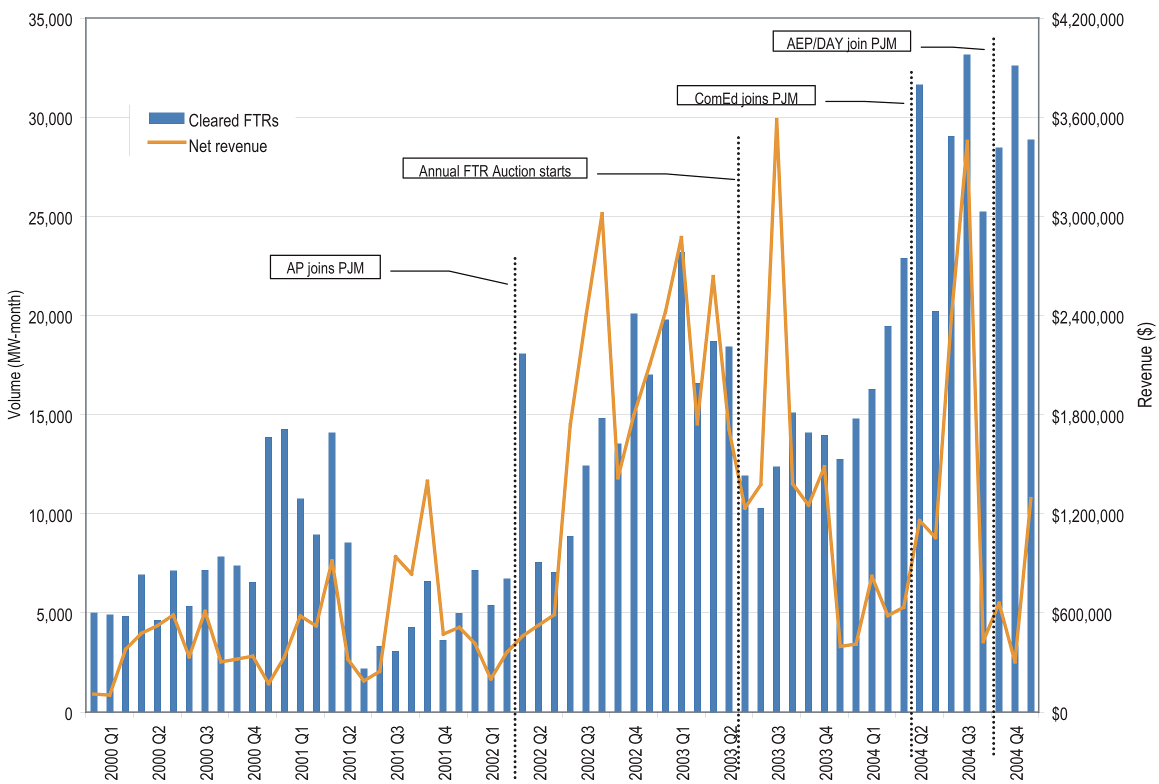


Figure 7-7 depicts the total cleared bid and offer volume together with the total auction revenue generated in Monthly FTR Auctions during calendar years 2000 through 2004. Average monthly auction revenue grew from $350,000 per month in 2000 to $600,000, $1.2 million and $1.8 million per month in 2001, 2002 and 2003, respectively, before declining to $1.1 million per month in 2004. Total volume increased from the historic average of 6,900 MW-months during calendar year 2000 and 2001 to 11,500 and 15,500 MW-months in 2002 and 2003, respectively. Total volume rose to 25,200 MW-months in 2004. As Figure 7-7 shows, monthly auction volume and revenue both declined on average immediately after PJM implemented the first Annual FTR Auction in June 2003. Volume grew steadily during the post-auction period.

Figure 7-7 - Monthly FTR Auction cleared volume and net revenue: Calendar years 2000 to 2004



Price

Table 7-8 shows the number of bids, volume, prices, and revenue for buy and sell bids, as well as totals for the sum of bids and volume and net revenue for Annual FTR Auction activity. Table 7-9 splits the buy activity into its bid and self-scheduled FTR components.

As Table 7-8 shows, during the 2004 to 2005 planning period, FTRs bought in the Mid-Atlantic Region were priced 10 times higher than those in the ComEd Control Zone, with the average cleared price for the former at $0.60 per MWh and for the latter $0.06. By contrast, FTRs sold in the ComEd Control Zone were priced 1.5 times higher than those in Mid-Atlantic Region, with an average cleared prices of approximately $0.33 per MWh for the former and $0.22 for the latter. The 2004 to 2005 planning period's Mid-Atlantic Region price increased $0.49 per MWh from the 2003 to 2004 planning period.

Table 7-9 shows buy activity in terms of its bid and self-scheduled components. Self-scheduled FTRs were priced $1.41 per MWh higher than bid FTRs, up $0.44 per MWh from a year ago, while Mid-Atlantic Region buy-bids were up $0.09 per MWh from the 2003 to 2004 planning period.

The average price paid in the Monthly FTR Auctions during the first seven months of the 2004 to 2005 planning period was $0.10 per MWh, down from $0.21 MWh over the 2003 to 2004 planning period.

Table 7-9 - Annual FTR Auction buy-bid volume, price and revenue: Planning period 2004 to 2005

Region/Zone Buy Activity	Bids	Bid MW	Cleared MW	Bid Price	Cleared Price	Revenue
Bid						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	5,675	233,467	26,285	$0.02	$0.06	$10,888,800
Mid-Atlantic	54,228	614,795	80,283	$0.14	$0.41	$218,711,402
Total	59,903	848,263	106,568	$0.11	$0.33	$229,600,202
Self-scheduled FTRs						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Atlantic	3,972	13,061	13,061	N/A	$1.74	$150,350,257
Total	3,972	13,061	13,061	N/A	$1.74	$150,350,257

-

The 2004 to 2005 planning period's price duration curves depicted in Figure 7-8 show that 81 percent of Mid-Atlantic Region annual FTRs were purchased for less than $1 per MWh and 90 percent for less than $2 per MWh. Nearly all, 99.9 percent, of ComEd Control Zone annual FTRs were purchased for less than $1 per MWh. Negative prices shown on duration curves occur because some FTRs are bid with negative prices, and some winning FTR bidders are paid to take FTRs.

Overall, average prices paid for the 2004 to 2005 planning period's annual FTR obligations were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. Comparable prices for the 2003 to 2004 planning period were $1.09 per MWh for 24-hour, $0.34 per MWh for on-peak and $0.15 per MWh for off-peak FTRs. The overall average prices paid for the 2004 to 2005 planning period annual FTR obligations and options were $0.31 per MWh and $0.19 per MWh, respectively, compared to $0.37 per MWh and $0.23 per MWh, respectively, in the 2003 to 2004 planning period. Average prices in Monthly FTR Auctions dropped from $0.51 per MWh in 2002, to $0.27 MWh in 2003, to $0.10 MWh in 2004.

Figure 7-8 - Annual FTR Auction buy-bid price duration curve: Planning period 2004 to 2005

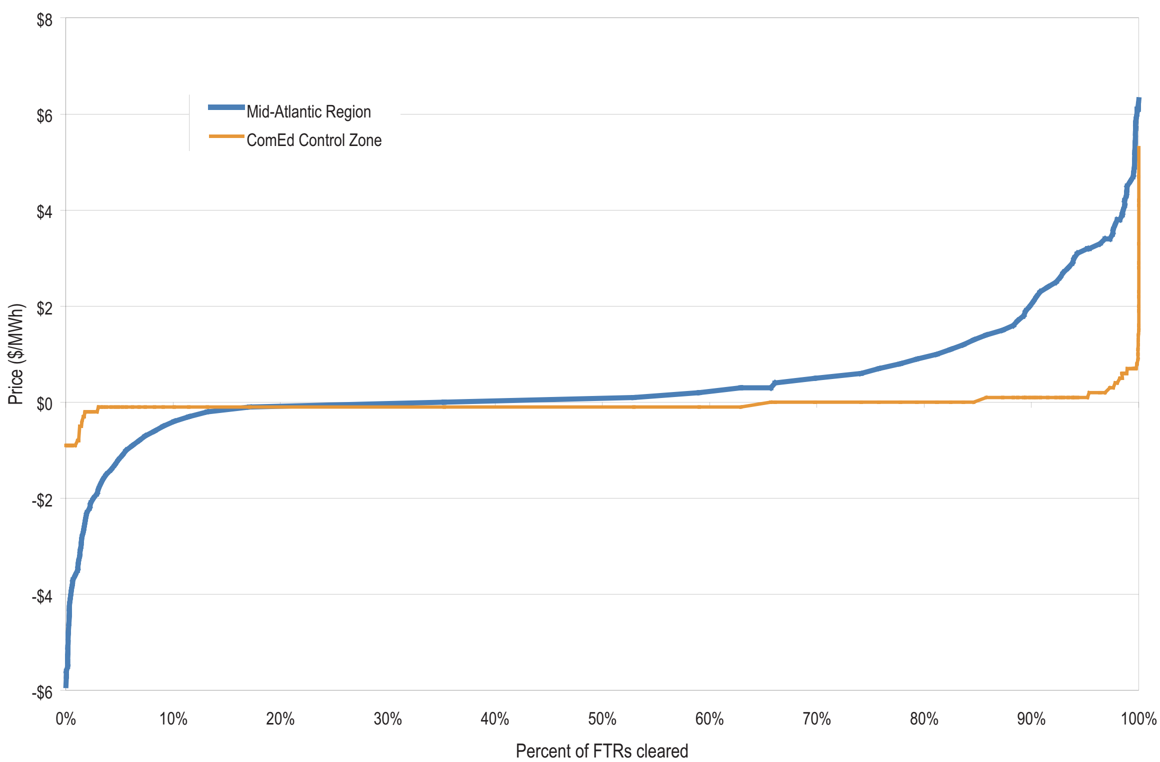
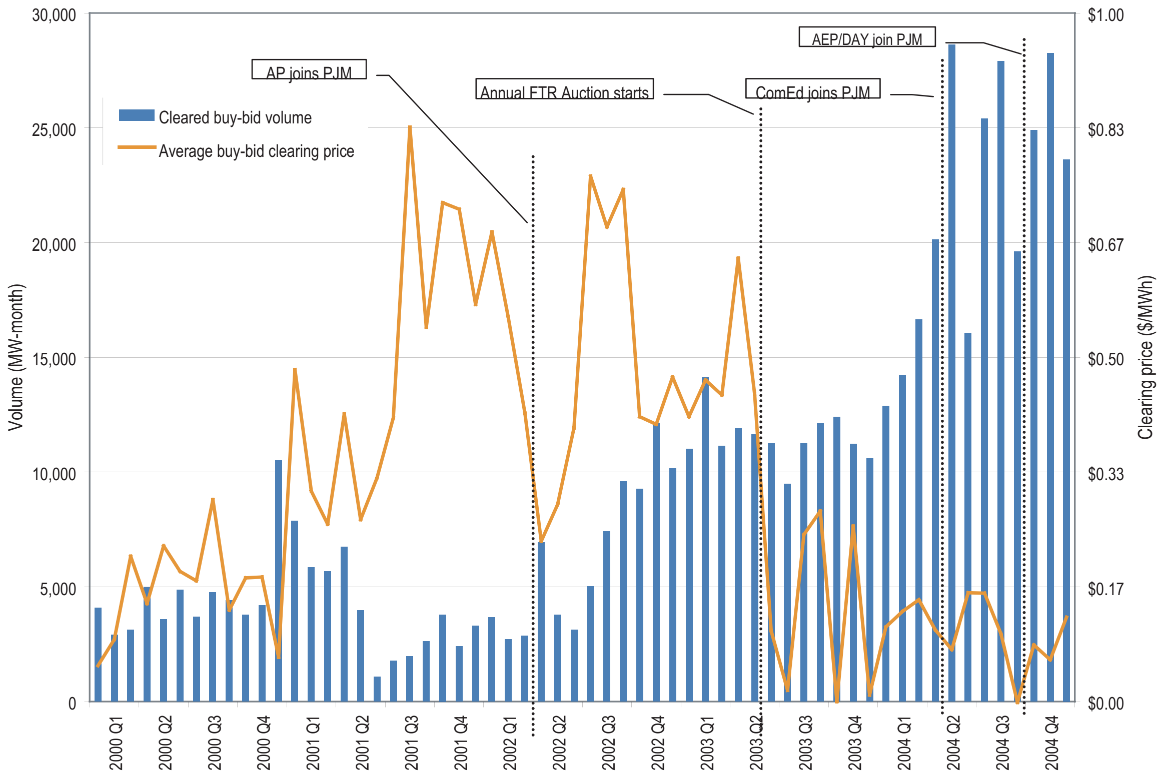


Figure 7-9 presents monthly FTR auction cleared-bid volume and average buy-bid clearing price. It shows that the average cleared-bid price dropped from an historic average of $0.49 per MWh during calendar years 2001 and 2002 to $0.27 per MWh in 2003 and to $0.10 per MWh in 2004, with the entire drop occurring after the start of the Annual FTR Auction. Volume steadily increased from 4,250 MW-months in 2000 and 2001 to 6,400, 11,500 and 21,500 MW-months in 2002, 2003 and 2004, respectively. A bid and offer volume comparison continues to show that bid volume exceeds offer volume by a ratio of nearly 10-to-1.

Figure 7-9 - Monthly FTR Auction cleared buy-bids and average buy-bid price: Calendar years 2000 to 2004



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. The difference between the sums of these payments and receipts creates most system congestion revenue.[24] When load pays more than generators receive, positive congestion revenue exists and is available to cover the target allocations of FTR holders. Load exceeds generation in constrained areas because some of this load is served by imports. Generation imports are paid the uncongested price at their bus. Generation in a constrained area receives the congested price and all load in the constrained area pays the congested price. As a result, load congestion payments are usually greater than the increased generation receipts. Table 7-10 illustrates how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined.

24 There are two other revenue sources available to be paid as FTR credits: 1) The negative revenue generated by FTRs that are in the direction opposite to congestion (such FTRs are a liability to the holders); and 2) Annual and monthly FTR auction revenue that remains after all ARRs are paid their full ARR target allocations. Table 7-5 shows $34 million in surplus FTR auction revenue for the 2004 to 2005 planning period to date.

As load and generation are equal on an overall system basis and the price of unconstrained energy is the same everywhere, any differences between load payments and generation credits is attributable to transmission congestion. FTR target allocations are equal to the product of the sink-minus-source LMP difference and the FTR MW. These are separated into positively and negatively valued FTRs, with the revenue from the negatively valued FTRs accruing to pay the positively valued FTRs. FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs, and these FTRs are paid 100 percent of their target allocations. The SFT ensures that the particular set of awarded FTRs can be supported by the transmission system, thus ensuring FTR revenue adequacy. In general, revenue adequacy exists when the SFT simulation adequately models system conditions and limitations that occur in Day-Ahead and Real-Time Energy Markets.

Table 7-10 - Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Congestion revenue

Pricing Node	Day-Ahead LMP	Load	Load Payments	Generation	Generation Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	
B	$15	50	$750	0	$0	
C	$20	50	$1,000	100	$2,000	
D	$25	50	$1,250	0	$0	
E	$30	50	$1,500	0	$0	
Total		200	$4,500	200	$3,000	$1,500

FTR target allocations

Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations
A-C	$10	50	$500	$500	$0
A-D	$15	50	$750	$750	$0
D-B	-$10	25	-$250	$0	-$250
B-E	$15	50	$750	$750	$0
Total				$2,000	-$250

Congestion accounting

Transmission congestion charges		$1,500
+Negative FTR target allocations		$250
=Total congestion charges		$1,750
Positive FTR target allocations	$2,000	
-FTR congestion credits	$1,750	
=Congestion credit deficiency	$250	
FTR payout ratio	0.875	

Although overall revenue adequacy is maintained throughout the entire planning period, revenue inadequacy can sometimes result because transmission facility ratings change with the season and instantaneous operating conditions. On lines and transformers, thermal ratings that limit power flow are affected primarily by temperature. Overallocation of FTRs is precluded by using the most restrictive rating set in the SFT simulation. When ratings change with the season, the actual instantaneous rating is never less than the rating used in the SFT. Instantaneous and planning period revenue adequacy are relatively certain for constraints associated with these facilities. Nonetheless, interface limits are voltage limits that are affected more by instantaneous operating conditions. Their variance over time is best described by distributions with large variances, not discrete values like lines and transformers.

Revenue inadequacy can also result if the SFT simulation does not adequately model system conditions and limitations that occur in the Day-Ahead Energy Market, or if there are systematic differences between actual and scheduled interface transactions.[25]

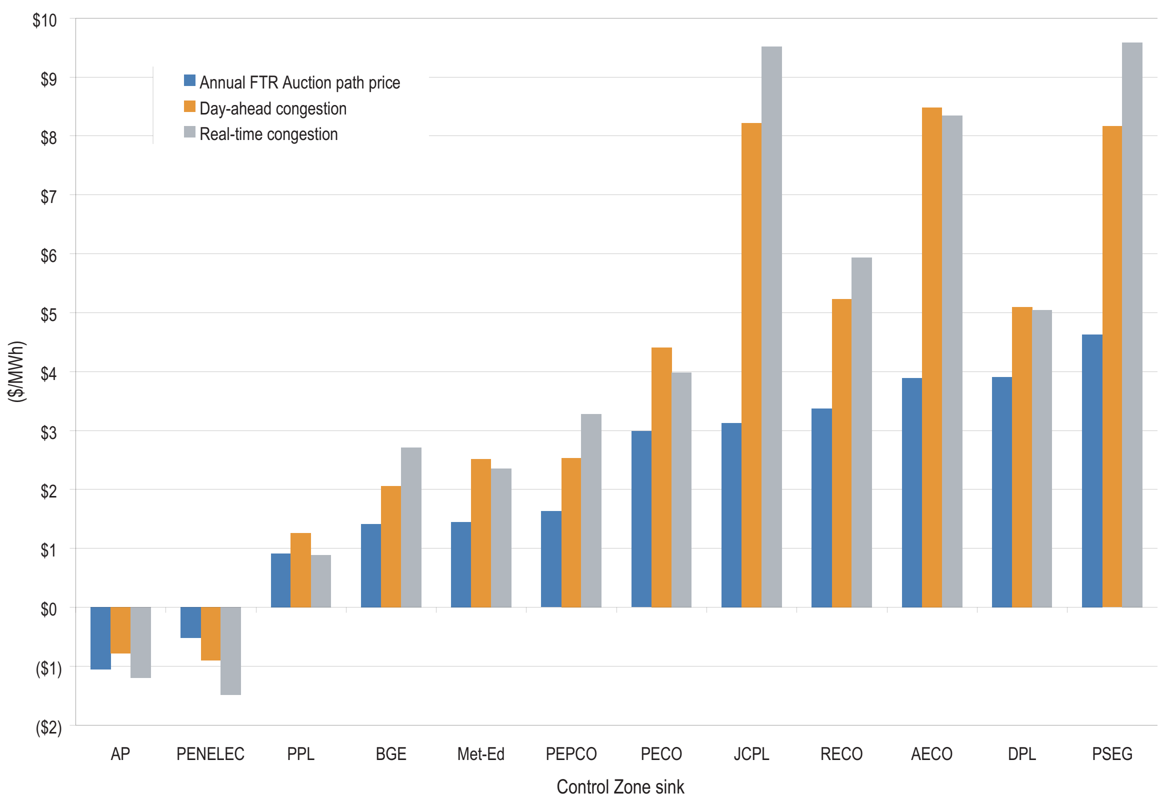
FTR target allocations are based on hourly, day-ahead FTR path prices and represent revenue required to hedge FTR holders fully against congestion. FTR credits represent revenue actually paid to FTR holders and, depending on market conditions, can be less than the target allocations needed to fully hedge congestion incurred during some periods. Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $16 million of the deficiencies for the 17-month period that ended May 31, 2004.[26] FTRs were paid at 98 percent of the target allocations during that period. FTRs through December 31, 2004, of the planning period ending May 31, 2005, have been paid at 97 percent of the target allocation level.[27]

25 See *2002 State of the Market Report* (March 05, 2003), pp. 56-59.
26 See Section 6, "Congestion," at Table 6-2, "Monthly PJM congestion accounting summary [Dollars (in millions)]: By planning period."
27 For full congestion accounting and FTR revenue adequacy data, see Section 6, "Congestion."

FTR Revenue versus Congestion

Figure 7-10 shows annual FTR auction prices and an approximate measure of day-ahead and real-time congestion for each Mid-Atlantic Region control zone with reference to Western Hub prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $3 per MWh in the Annual FTR Auction and that about $4.40 per MWh of day-ahead congestion and $4 per MWh of real-time congestion existed between the Western Hub and the zone. The data show that congestion costs, approximated in this way, exceeded the cost of FTRs for most zones.

Figure 7-10 - Annual FTR Auction prices vs. average day-ahead and real-time congestion for Mid-Atlantic Region Control Zones relative to the Western Hub: Planning period 2004 to 2005



A separate analysis examined FTR target allocations. Hourly FTR target allocations were segregated into those that were benefits and liabilities and summed by sink and by source for the calendar year 2004. Figure 7-11 shows the FTR sinks with the largest targeted benefit and liability. The top 10 sinks that produced a financial benefit accounted for 76 percent of total positive target allocations. These sinks were spread throughout PJM. FTRs with the AP Control Zone as their sink included 38 percent of all positive target allocations. The top 10 sinks that created liability accounted for 59 percent of total negative target allocations. These sinks were also spread throughout PJM. FTRs with the ComEd Control Zone as the sink encompassed 63 percent of all negative target allocations.

Figure 7-11 - Ten largest positive and negative FTR target allocations summed by sink: Calendar year 2004

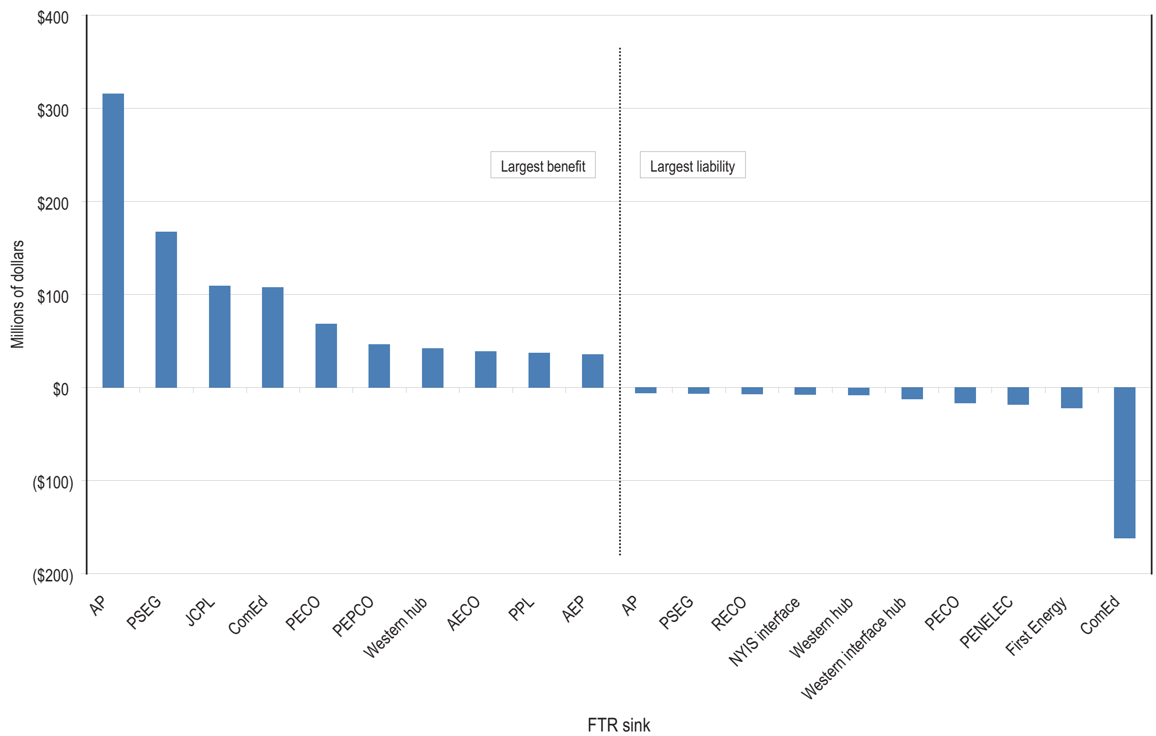
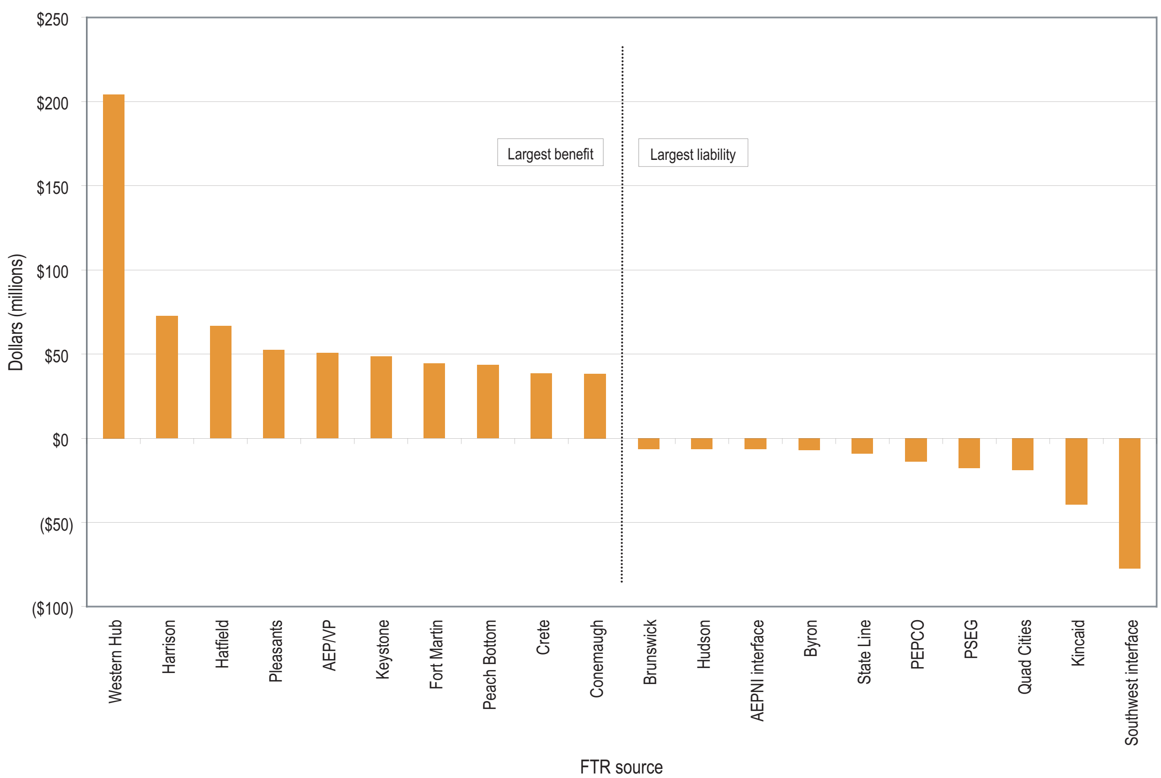
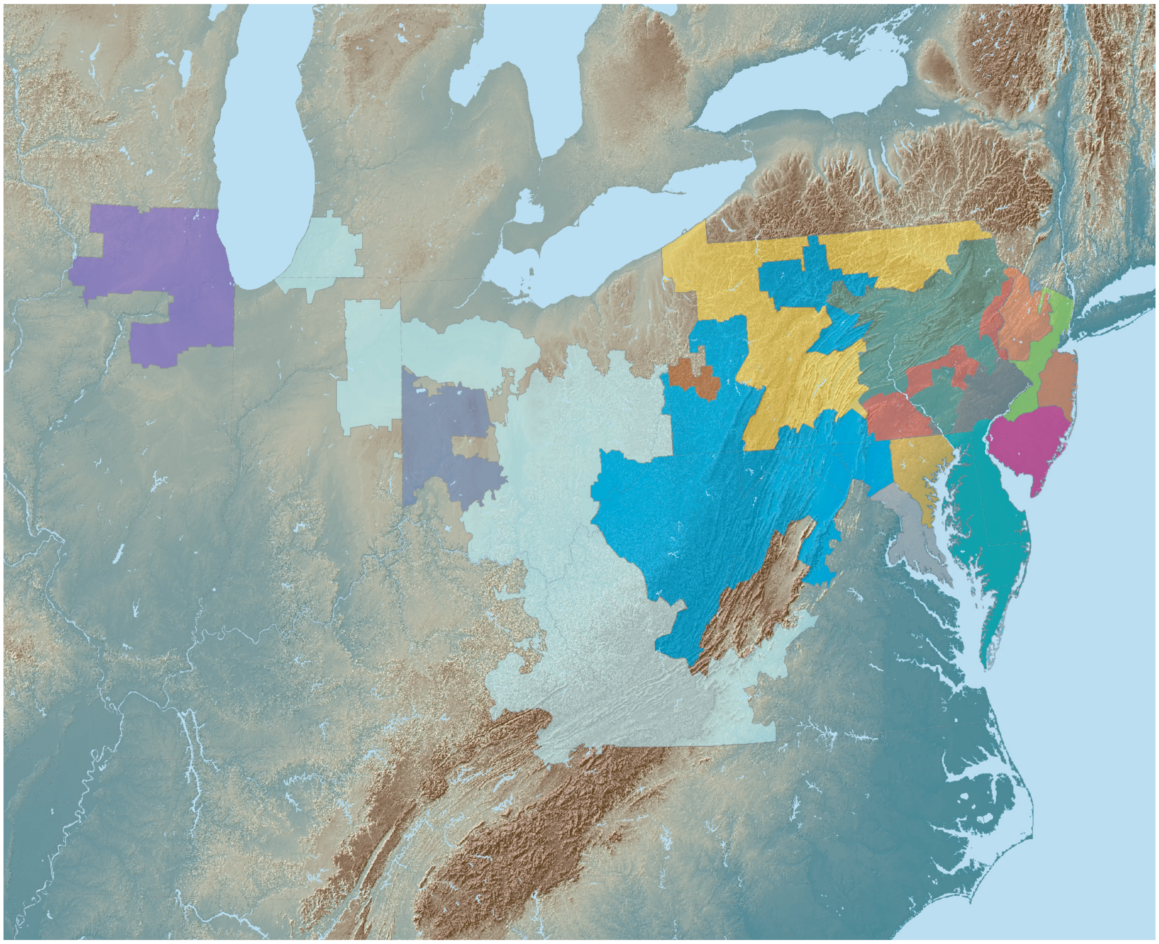


Figure 7-12 shows the same information for FTR sources. The top 10 sources that created financial benefit accounted for 52 percent of total positive target allocations. Eight of these 10 sources were located in or near the AP Control Zone. FTRs with the Western Hub as their source included 25 percent of all positive target allocations. The top 10 sources that were a liability accounted for 45 percent of total negative target allocations. These sources were generally located at the far western and eastern ends of PJM. FTRs with the southwest interface as the source encompassed more than 30 percent of all negative target allocations.

Figure 7-12 - Ten largest positive and negative FTR target allocations summed by source: Calendar year 2004



APPENDIX A - PJM SERVICE TERRITORY



Legend

ZONE

- Allegheny Power Systems
- American Electric Power Co., Inc.
- Atlantic Electric Company
- Baltimore Gas and Electric Company
- Commonwealth Edison
- Dayton Power and Light Co.
- Delmarva Power and Light Company
- Duquesne Light
- Jersey Central Power and Light Company
- Metropolitan Edison Company
- PPL Electric Utilities
- Peco Energy Company
- Pennsylvania Electric Company
- Potomac Electric Power Company
- Public Service Electric and Gas Company
- Rockland Electric Company

APPENDIX B - PJM MARKET MILESTONES

YEAR	MONTH	EVENT
1996	April	FERC Order 888
1997	April	Offer-based Energy Market
	November	FERC approval of PJM ISO status
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	April	Competitive energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	First PJM Emergency and Economic Load-Response Programs
2002	April	Integration of the AP Control Zone into PJM Western Region
	June	Second PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of full PJM RTO status
2003	May	Annual FTR Auction
2004	May	Integration of the ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region