SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give firm transmission customers an offset against congestion costs. In PJM, FTRs have been made available to firm point-to-point and network service transmission customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998.[1]

FTRs and ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational price differences actually experienced in the Day-Ahead Energy Market. ARRs provide holders with revenues or charges based on the locational price difference between ARR sources and sinks determined in the Annual FTR Auction.[2] These price differences are based on the bid prices of participants in the Annual FTR Auction Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR Auction participants' expectations of locational price differences in the Day-Ahead Energy Market. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

Firm transmission customers have access to FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission customers receive requested FTRs to the extent that they are consistent both with the physical capability of the transmission system and with FTR requests of other eligible customers.

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[3] Firm transmission customers have the option either to take allocated ARRs or to take the underlying FTRs through a process called self-scheduling.

PJM also runs Monthly FTR Auctions designed to permit bilateral FTR transactions and to allow any market participant to buy residual system FTRs. PJM introduced 24-hour FTRs into the Monthly Auctions for the 2003 to 2004 planning period. At the same time, PJM also added annual and monthly FTR option products to the FTR Auction Market. Unlike standard FTRs, the FTR options can never be a financial liability.

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[4]

1 PJM network and firm, long-term point-to-point transmission service customers are referred to as eligible customers.

2 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.

3 87 FERC ¶ 61,054 (1999).

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

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[5] and the Allegheny Power Company (AP) Control Zone.[6]

- **Phase 2 (2004).** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[7]

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

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

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

The *2005 State of the Market* Report focuses on two FTR/ARR planning periods: the 2004 to 2005 planning period which covers June 1, 2004, to May 31, 2005, and the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006.[8]

For the 2005 to 2006 planning period (June 1, 2005, through May 31, 2006), ARR allocations were provided to eligible market participants in the Mid-Atlantic Region and AP Control Zone. The choice of ARRs or direct allocation FTRs was available in the recently integrated ComEd, AEP, DAY, DLCO and Dominion Control Zones. Participants in newly integrated control zones retain the option of ARR allocations or direct allocation FTRs for the two planning periods following integration. After that, they can participate fully in the FTR Markets and receive ARR allocations through the PJM allocation process. For example, since its May 1, 2004, integration, direct allocation FTRs were available to participants in the ComEd Control Zone for the 2004 to 2005 planning period and for the 2005 to 2006 planning period. For subsequent periods, eligible customers in the ComEd Control Zone will be full participants in the ARR allocation process.

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

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

7 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).

8 Annual FTR accounting changed from calendar year to planning period 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.

Overview

Financial Transmission Rights (FTRs)

- **Products.** FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, off-peak and on-peak periods.

- **Supply and Demand.** PJM operates an Annual FTR Auction Market for all zones in the PJM footprint. Participants in newly integrated zones must choose to receive either an FTR allocation or an ARR allocation before the start of Annual FTR Auction. In the Annual Auction Market, total FTR Auction demand was 871,841 MW during the 2005 to 2006 planning period, up from 861,323 MW during the 2004 to 2005 planning period. The Auction Market cleared 141,179 MW (16.2 percent of demand), leaving 730,662 MW of uncleared bids. In the FTR Auction Market for the 2004 to 2005 planning period, the demand was 861,323 MW while the market cleared only 119,629 MW (13.9 percent of demand), leaving uncleared bids of 741,694 MW. Under the Annual FTR Auction, there is no limit on FTR demand. 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. The principal binding constraints limiting the supply of FTRs were the Jefferson 138 kV line, the Mahans Lane 138 kV line and the Branchburg 500/230 kV transformer.

  In the allocation of FTRs or ARRs for the ComEd, AEP, DAY, DLCO and Dominion Control Zones, total demand for annual FTR allocations was 42,641 MW for the 2005 to 2006 planning period, down from 65,757 MW for the 2004 to 2005 planning period. This decrease was the net result of a number of factors including the AP Control Zone becoming ineligible for direct allocation FTRs, increased demand by customers in the ComEd Control Zone for ARRs rather than directly allocated FTRs and the integration of Dominion. Demand for allocations cleared at 39,429 MW, leaving uncleared bids of 3,212 MW. The principal binding constraints limiting the supply of allocated FTRs were the Chesterfield-Lakeside 230 kV line, the Kanawha River-Matt Funk 345 kV line, the South Canton transformer and the Crete-St Johns 345 kV line, and the Bedington-Black Oak interface.

  In addition to the Annual FTR Auction and allocation markets, PJM conducts Monthly FTR Auction Markets covering the entire PJM footprint, to allow participants to buy and sell any residual transmission entitlement that is available after FTRs are awarded from the Annual FTR Auction. Any market participant can participate in the Monthly Auctions as a buyer or as a seller.

- **Ownership Concentration.** Ownership of FTRs is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual Auction. Given PJM's Annual and Monthly FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments.

- **Volume.** Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,609 MW (19.7 percent) were cleared. Of 927,081 MW[9] in annual FTR requests for the 2004 to 2005 planning period, 179,950 MW (19.4 percent) were cleared.

9 The number reported here is slightly higher than the number reported in *2004 State of the Market Report*, which was 924,154 MW, because the number reported here includes 1,524 MW of requested bids in the DLCO Control Zone and 1,402 MW of additional requested bids in the AEP and DAY Control Zones.

- **Price.** For the 2005 to 2006 planning period, 84.3 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 89.1 percent for less than $2 per MWh. The overall average prices paid for annual FTR obligations were $1.56 per MWh for 24-hour, $0.40 per MWh for on-peak and $0.33 per MWh for off-peak FTRs. Comparable prices for the 2004 to 2005 planning period were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. The overall average prices paid for 2005 to 2006 planning period annual FTR obligations and options were $0.10 per MWh and $0.18 per MWh, respectively, compared to $0.31 per MWh and $0.19 per MWh, respectively, in the 2004 to 2005 planning period.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,672 million of FTR revenues during the first seven months of the 2005 to 2006 planning period and $1,118 million during the 12-month 2004 to 2005 planning period.[10]

- **Revenue Adequacy.** FTRs were paid at 91 percent of the target allocation level for the 2005 to 2006 planning period, through the end of calendar year 2005.[11] FTRs were 100 percent revenue adequate during the 2004 to 2005 planning period.

Auction Revenue Rights (ARRs)

- **Supply and Demand.** Total demand in the annual ARR allocation was 82,343 MW for the 2005 to 2006 planning period, up from 55,128 MW during the 2004 to 2005 planning period and 39,888 MW during the 2003 to 2004 planning period. ARR demand is limited by the 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.

- **Volume.** Of 82,343 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW were allocated. Eligible market participants subsequently self-scheduled 32,631 MW (55 percent) of these allocated ARRs as annual FTRs. 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 (39 percent) of these allocated ARRs as annual FTRs.

- **Revenue.** Revenues from the Annual FTR Auction are first distributed to ARR holders based on ARR target allocations. If that revenue is not sufficient to meet ARR target allocations, then revenues from Monthly FTR Auctions are used to make up any shortfall. For the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $892 million from the combined Annual and Monthly FTR Auctions through the end of calendar year 2005, making ARRs revenue adequate. During the 2004 to 2005 planning period, the ARR target allocations were $345 million while PJM collected $385 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate.

10 See Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."
11 See Section 7, "Congestion," for an additional discussion of FTR revenue adequacy.

Conclusion

The annual ARR allocation and the Annual FTR Auction together provide long-term, firm transmission customers with a mechanism to hedge congestion and provide all market participants increased access to long-term FTRs. The Annual FTR Auction allows a market valuation of FTRs. The 2005 FTR Auction Market results were competitive and succeeded in providing all qualified market participants with equal access to FTRs. A potential barrier to competition was removed by implementing the rules which explicitly allow that the ARRs with positive economic values (FTRs in newly integrated zones) follow load as load shifts among suppliers, although the fact that the underlying FTRs do not also follow load in the case of self-scheduled ARRs should also be addressed. FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005, and at 91 percent of the target allocation level for the first seven months of the planning period ending May 31, 2006. Although in the aggregate, FTRs provided a hedge against 100 percent of the target allocation level during the 12-month period that ended May 31, 2005, 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.

Financial Transmission Rights

While 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 2005 to 2006 planning period, the auction covered all zones. Eligible participants in the AEP, DAY, DLCO and Dominion Control Zones received transitional, direct allocation FTRs.[12]

FTRs are financial instruments that entitle their holders to receive revenue based on prices in the Day-Ahead Energy Market. The FTR target allocation is equal to the product of the FTR MW and the price differences between sink and source that occur in the 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 amount of FTR revenues collected, FTR holders may receive congestion credits between zero and their target allocations. When FTR holders receive their target allocation, the associated FTRs are fully funded.

FTR Products

There are two FTR product types: FTR obligations and FTR options. An FTR obligation provides a credit, positive or negative, equal to the product of the FTR MW and the price difference between sink and source that occurs in the Day-Ahead Energy Market. An FTR option provides only positive credits.

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

12 AEP and DAY joined PJM on October 1, 2004. DLCO joined PJM on January 1, 2005. Dominion joined PJM on May 1, 2005.

Market Structure

Prior to implementation of 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 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 increased.

Supply and Demand

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the ability to self-schedule the 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 as direct allocation FTRs (available to customers in recently integrated control zones), in Monthly FTR Auctions and via bilateral trades of existing FTRs.

During any planning period including newly integrated control zones, eligible customers in those control zones 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 transition period. Table 8-1 summarizes the availability of ARRs and direct allocation FTRs within the different regions and control zones.

Table 8-1 - Eligibility for ARRs vs. directly allocated FTRs

	PJM Integration Date	ARRs	Direct Allocation FTRs
Mid-Atlantic	01-Apr-99	Yes	No
AP	01-Apr-02	Yes	No
ComEd	01-May-04	Yes	Through 2005/2006 planning period
AEP/DAY	01-Oct-04	Yes	Through 2006/2007 planning period
DLCO	01-Jan-05	Yes	Through 2006/2007 planning period
Dominion	01-May-05	Yes	Through 2007/2008 planning period

Each March, PJM conducts an Annual FTR Auction during which all eligible market participants can bid on FTRs for the next planning period 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 net revenue based on offer-based value of FTRs.[13] 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 each of the four rounds. Self-scheduled FTRs must have the same source and sink as the ARR. Self-scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

13 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 maximum 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.

- **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.

By self-scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can 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 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 available due to residual transmission system capability or the sale of FTRs by participants, 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 FTRs through the PJM-administered, bilateral market or market participants can trade FTRs among themselves without PJM involvement.

Table 8-2 shows that for the 2005 to 2006 planning period, 141,179 MW of annual FTR bids were cleared in the Annual FTR Auction for all zones in the PJM footprint while 39,429 MW of annual FTR allocation requests were cleared in the annual FTR allocation for the ComEd, AEP, DAY, DLCO and Dominion Control Zones. A total of 978,462 MW were bid, offered, or requested to be allocated. By comparison, for the 2004 to 2005 planning period, a total of 977,861 MW of annual FTRs were bid, offered, or requested to be allocated.

Table 8-2 - Annual FTR Market volume: Planning period 2005 to 2006

	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)
Buy Bid (Auction)			
All PJM Zones	84,381	871,841	141,179
Bid Request (Allocation)			
ComEd	34	1,170	1,138
AEP/DAY	639	24,492	24,487
DLCO	48	632	489
Dominion	283	16,348	13,315
Total	85,385	914,483	180,609
Sell Offer (Auction)			
All PJM Zones	11,067	63,979	4,543
TOTAL	96,452	978,462	185,152

As Table 8-2 shows, annual FTR demand for both the auction and allocation in PJM was 914,483 MW during the 2005 to 2006 planning period, compared with 927,081 MW for the 2004 to 2005 planning period.

Under the current rules, participants may submit unlimited bids for FTRs based on a variety of financial strategies. 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. For the requested FTRs for the 2005 to 2006 planning period, bids for 185,152 MW were met by available supply, leaving 793,310 MW of demand unfulfilled. Table 8-3 lists the principal constraints that precluded awarding all FTRs requested.

Table 8-3 - Annual FTR Auction and allocation principal binding transmission constraints: Planning period 2005 to 2006

	Principal Constraints
Mid-Atlantic/AP/ComEd	Jefferson 138 kV, Mahans Lane 138 kV, Branchburg transformer derated
AEP/DAY	Kanawha River-Matt Funk 345 kV
DLCO	South Canton transformer, Crete-St Johns 345 kV
Dominion	Bedington-Black Oak Interface, Chesterfield-Lakeside 230 kV

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 4,226 MW of FTRs traded in calendar year 2005, as compared to 1,650 MW[14] in calendar year 2004, 1,352 MW in calendar year 2003 and 7,173 MW in calendar year 2002.

Ownership Concentration

The ownership of FTR products resulting from the 2005 to 2006 Annual FTR Auction was analyzed. The FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly FTR Auction Market or secondary bilateral market.

Herfindahl-Hirschman Index (HHI) results for each FTR product are based on the outcome of the Annual FTR Auction. For FTR obligations, HHIs were found to be 1144 for 24-hour, 1237 for off-peak and 1107 for on-peak FTR products while maximum market shares were 22 percent for 24-hour, 20 percent for off-peak and 18 percent for on-peak FTR products.

For FTR options, HHIs were found to be 8173 for 24-hour, 1420 for off-peak and 1581 for on-peak products while maximum market shares were 90 percent for 24-hour, 25 percent for off-peak and 26 percent for on-peak FTR products.

This ownership information is only descriptive and is not a measure of actual or potential FTR market structure issues as the ownership positions resulted from a competitive auction.

14 This number was updated for 2004 calendar year.

Market Performance

Volume

For the entire PJM footprint for the 2005 to 2006 planning period, 180,609 MW of annual FTRs, from both Annual FTR Auction and direct allocation FTR for new zones, were purchased and allocated out of 914,483 MW bid and requested. For Annual FTR Auction excluding request for direct allocation FTR, 145,722 MW were purchased and sold out of 935,820 MW bid and offered. (See Table 8-2.) Eligible market participants converted 32,631 MW of ARRs into annual FTRs. In comparison, during the 2004 to 2005 planning period, 179,950 MW were purchased and allocated, with 93,344 MW purchased and allocated in the Mid-Atlantic Region and 8,874 MW purchased and allocated in the AP Control Zone. For the 2004 to 2005 planning period, eligible market participants converted 13,061 MW of Mid-Atlantic Region ARRs into annual FTRs.

Price

Table 8-4 shows average prices paid for FTR obligations during the 2004 to 2005 and the 2005 to 2006 planning period.

Table 8-4 shows the overall average prices paid for annual FTR obligations. For the 2005 to 2006 planning period, annual FTR obligation prices were $1.56 per MWh for 24-hour, $0.40 per MWh for on-peak and $0.33 per MWh for off-peak FTRs. Comparable prices for the 2004 to 2005 planning period were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs.

The overall average prices paid for the 2005 to 2006 planning period annual FTR obligations and options were $0.10 per MWh and $0.18 per MWh, compared to $0.31 per MWh and $0.19 per MWh, in the 2004 to 2005 planning period. Average prices in Monthly FTR Auctions increased to $0.18 per MWh in 2005 from $0.10 per MWh in 2004.

Table 8-4 - Annual prices for FTR obligations

Planning Period	24-Hour ($/MWh)	On Peak ($/MWh)	Off Peak ($/MWh)
2004/2005	$1.27	$0.16	$0.13
2005/2006	$1.56	$0.40	$0.33

Table 8-5 shows the Annual FTR Auction data. (Table 8-2 shows both Annual Auction data and annual allocation requests.) A total of 871,841 MW were bid and a total of 63,979 MW were offered. By comparison, for the 2004 to 2005 planning period, a total of 927,081 MW were bid and requested and a total of 50,780 MW were offered.

Table 8-5 - Annual FTR Auction Market volume, price and revenue: Planning period 2005 to 2006

	Bids	Bid MW	Cleared MW	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue
All PJM Zones						
Buy and Self-Scheduled Bids	84,381	871,841	141,179	$0.20	$0.71	$881,747,900
Sell Offers	11,067	63,979	4,543	$0.09	$0.00	($109,966)
Net	95,448	935,820	145,722	$0.19	$0.69	$881,637,934

Table 8-5 shows the number of bids and the volume, price and revenue for buy and sell bids, as well as totals for the sum of bids and volume and net revenue for the Annual FTR Auction activity. Table 8-6 splits the buy activity into its buy bid and self-scheduled FTR components.

Table 8-6 shows buy activity in terms of its bid and self-scheduled components. Self-scheduled FTRs were priced $1.60 per MWh higher than bid FTRs, up $0.20 per MWh from a year ago, while Mid-Atlantic Region, AP and ComEd Control Zones buy-bids were up $0.09 per MWh from the weighted bid price of 2004 to 2005 planning period.

The average price paid in the Monthly FTR Auctions during the first seven months of the 2005 to 2006 planning period was $0.10 per MWh, compared with $0.09 MWh over the 2004 to 2005 planning period.

Table 8-6 - Annual FTR Auction bid volume, price and revenue: Planning period 2005 to 2006

	Bids	Bid MW	Cleared MW	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue
All PJM Zones						
Buy Bids	79,809	839,210	108,549	$0.20	$0.34	$326,145,970
Self-scheduled Bids	4,572	32,631	32,631	NA	$1.94	$555,601,930

The 2005 to 2006 planning period's price duration curve in Figure 8-1 shows that 84.3 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 89.1 percent for less than $2 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs.

Figure 8-1 - Annual FTR Auction buy-bid price duration curve: Planning period 2005 to 2006

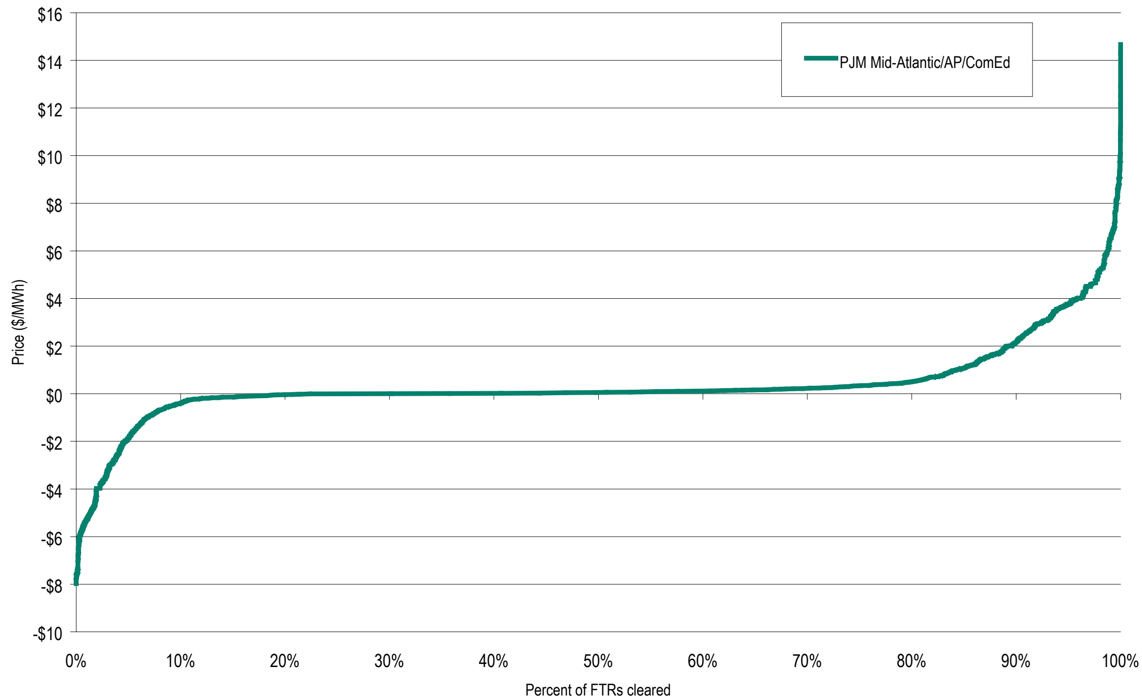
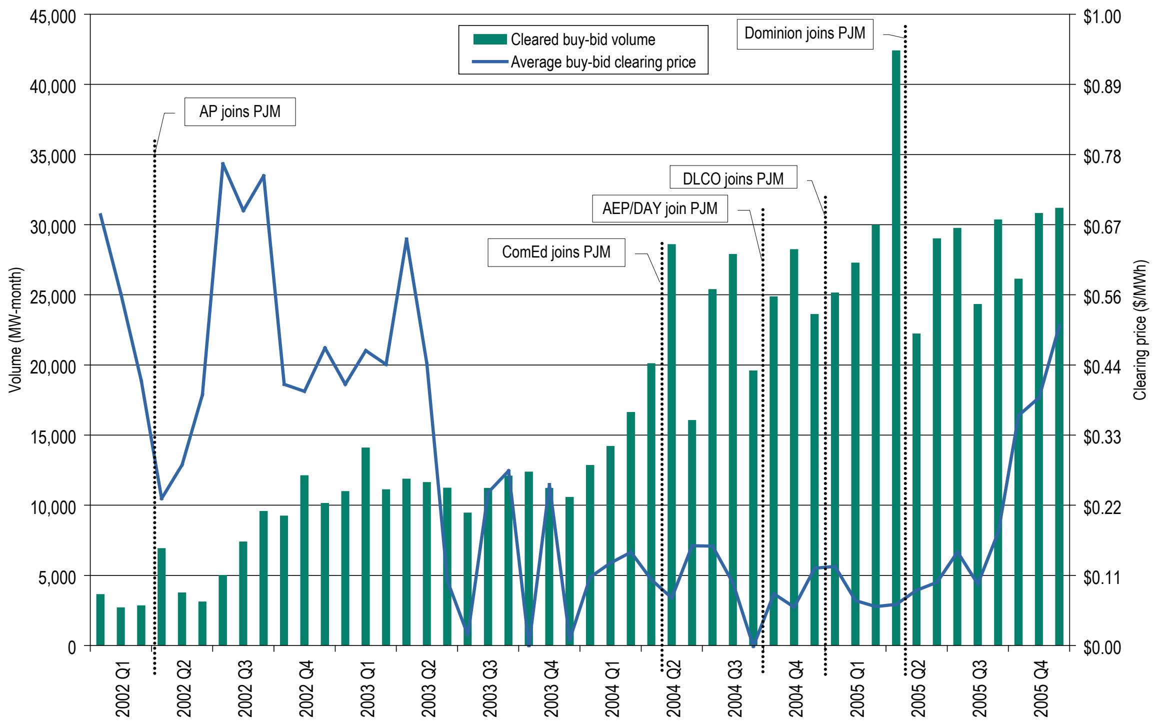


Figure 8-2 presents Monthly FTR Auction cleared-bid volume and average buy-bid clearing price. It shows that the average cleared-bid price dropped from 2002 to 2003 and 2004, but then rose in 2005. Volume steadily increased from 2002 through 2005.

Figure 8-2 - Monthly FTR Auction cleared buy-bids and average buy-bid price: Calendar years 2002 to 2005



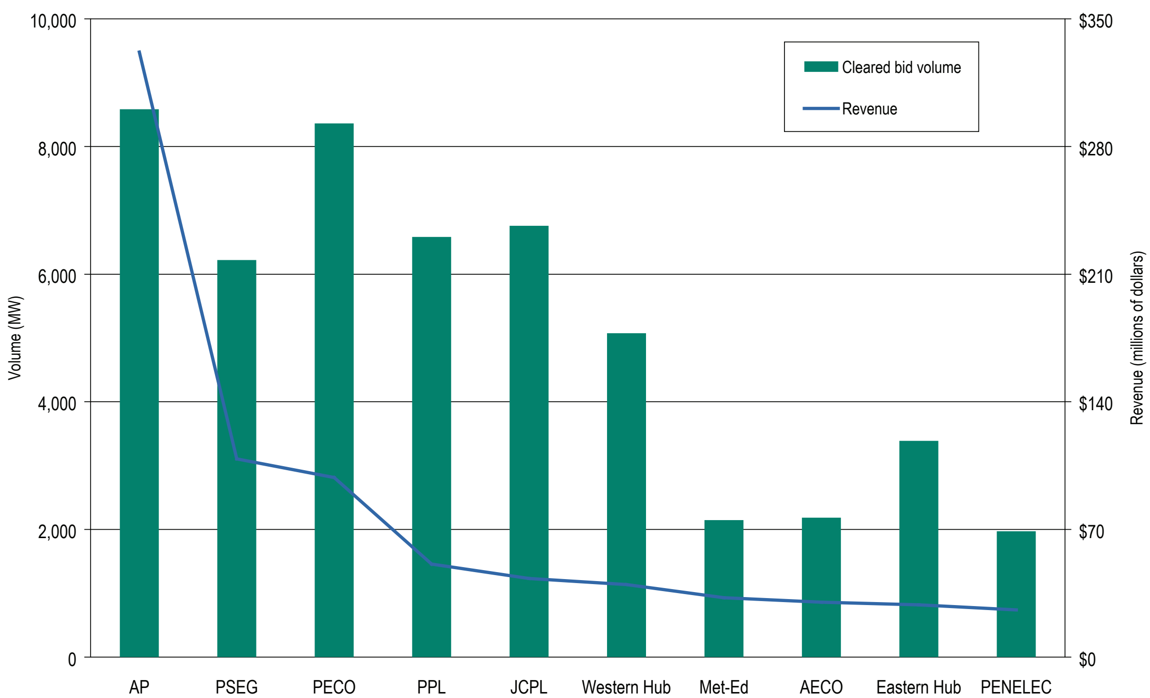
Revenue

Table 8-5 shows Annual FTR Auction summary data. During the 2005 to 2006 planning period, the Annual FTR Auctions for the ComEd Control Zone, AP and the Mid-Atlantic Region netted $881.6 million in revenue, with buyers paying $881.7 million and sellers receiving $0.1 million. By contrast, for the 2004 to 2005 planning period, the Mid-Atlantic Region and the ComEd Control Zone Annual FTR Auction netted $369.6 million in revenue, with buyers paying $380 million and sellers receiving $10.4 million.

Annual Auction Revenue

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the 10 FTR sinks (destinations) that produced the most Annual FTR Auction revenue for the 2005 to 2006 planning period. FTRs to these sinks accounted for $790 million or about 89.6 percent of all revenue paid[15] in the Annual FTR Auction and constituted 36.3 percent of all FTRs bought in the Annual FTR Auction for the 2005 to 2006 planning period.

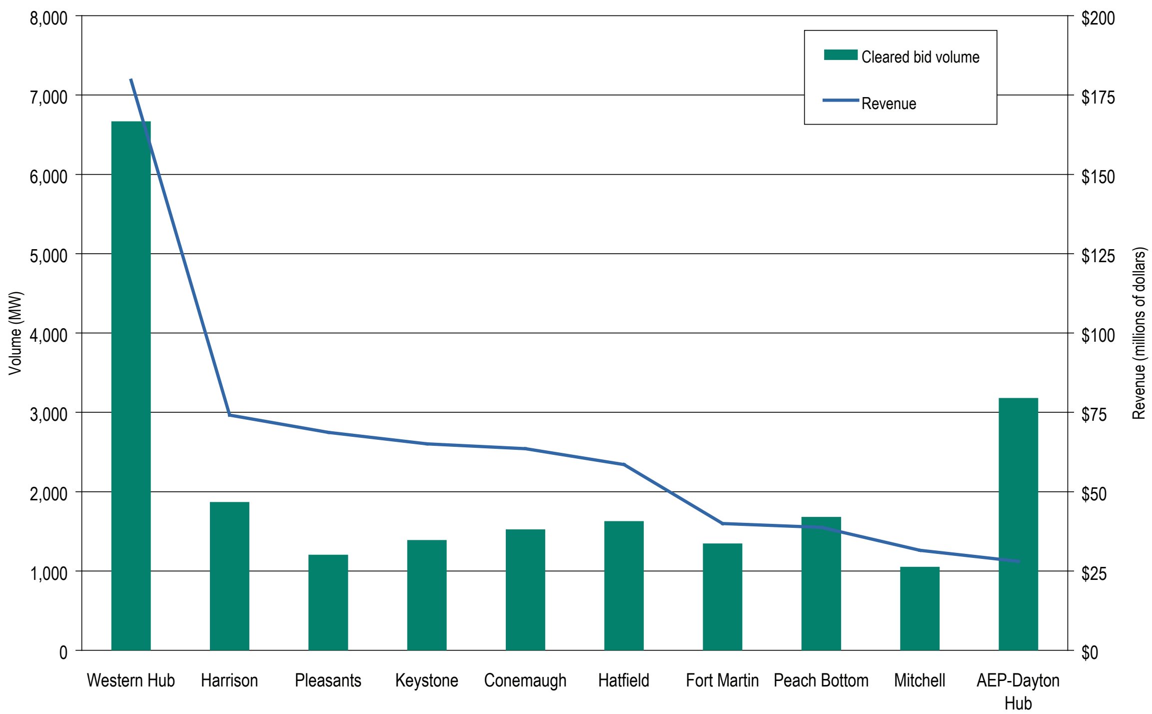
Figure 8-3 - Highest revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2005 to 2006



15 As some FTRs are bid with negative prices, some winning FTR bidders are 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 8-4 summarizes 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 2005 to 2006 planning period. FTRs from these sources accounted for $648 million or about 73.5 percent of all revenue paid and included 15.3 percent of all FTRs bought in the Annual FTR Auction. These sources are generally located at large generating facilities throughout the Mid-Atlantic Region.

Figure 8-4 - Highest revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2005 to 2006



Monthly FTR Auction Revenue

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the 10 FTR sinks that produced the most Monthly FTR Auction revenue during the first seven months of the 2005 to 2006 planning period. FTRs to these sinks accounted for $42.8 million and included 18.1 percent of all FTRs bought in Monthly FTR Auctions.

Figure 8-5 - Highest revenue producing FTR sinks purchased in the Monthly FTR Auctions: Planning period 2005 to 2006 through December 31, 2005

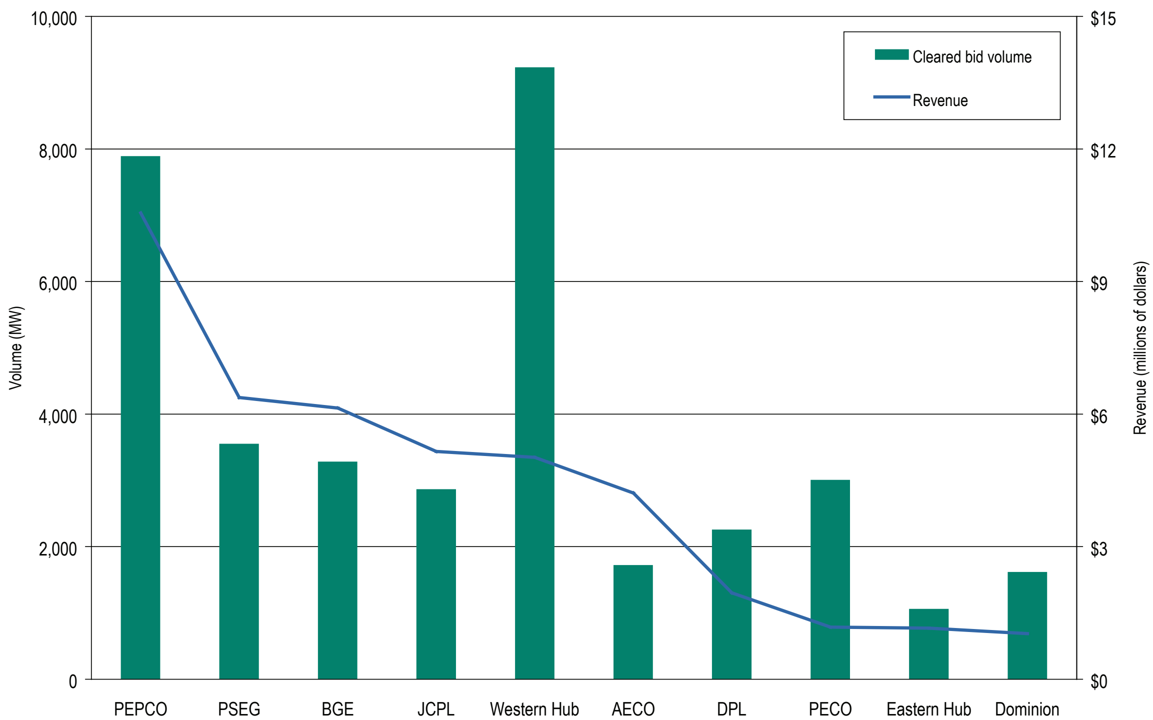


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the 10 FTR sources that produced the most Monthly FTR Auction revenue during the first seven months of the 2005 to 2006 planning period. FTRs from these sources accounted for $54.4 million and included 13.9 percent of all FTRs bought in Monthly FTR Auctions.

Figure 8-6 - Highest revenue producing FTR sources purchased in Monthly FTR Auctions: Planning period 2005 to 2006 through December 31, 2005

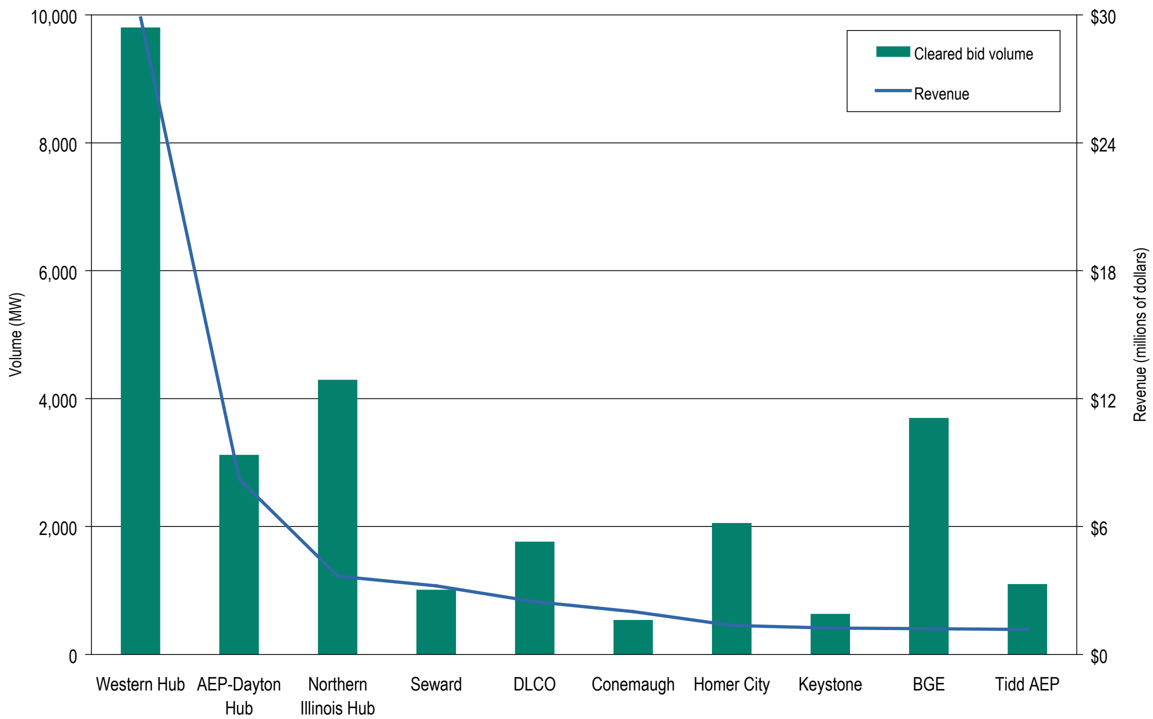
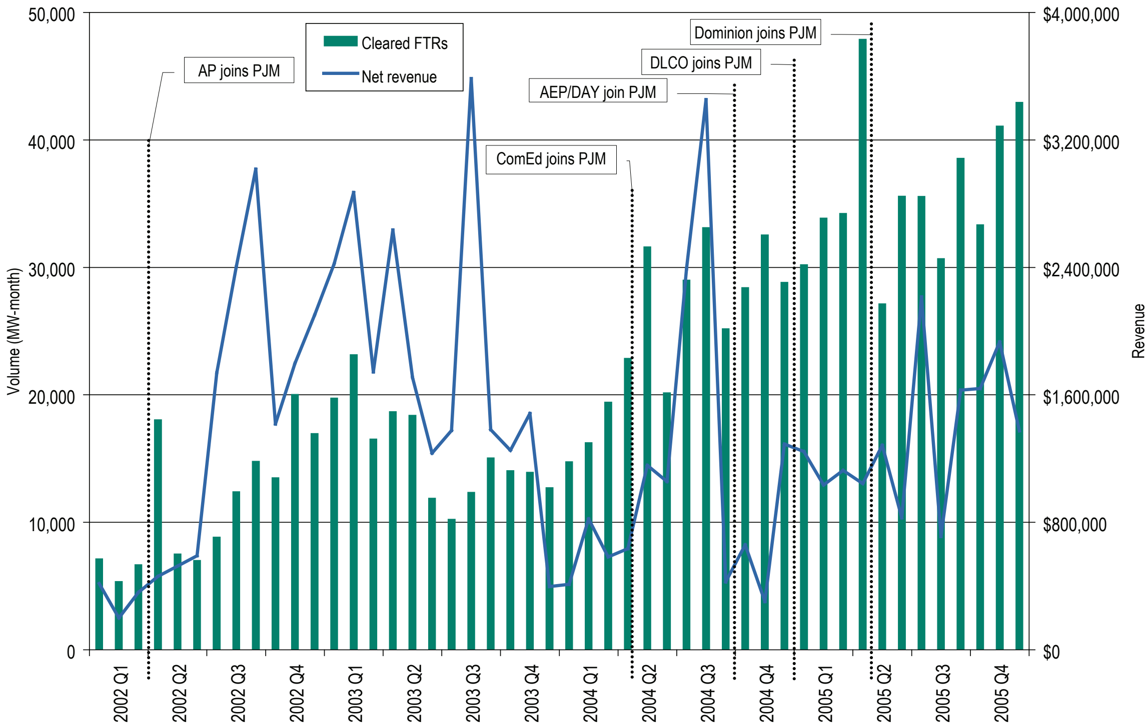


Figure 8-7 depicts the total cleared volume together with the total auction revenue generated in Monthly FTR Auctions during calendar years 2002 through 2005. Average monthly revenue in 2005 was about $1.3 million per month. The average volume for the period January 1, 2005, through December 31, 2005, was 36,000 MW-month.

Figure 8-7 - Monthly FTR Auction cleared volume and net revenue: Calendar years 2002 to 2005



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The MW of load exceeds the MW of generation in constrained areas because a part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. 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 congestion-related increase in payments to generation. Table 8-7 illustrates how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined. In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

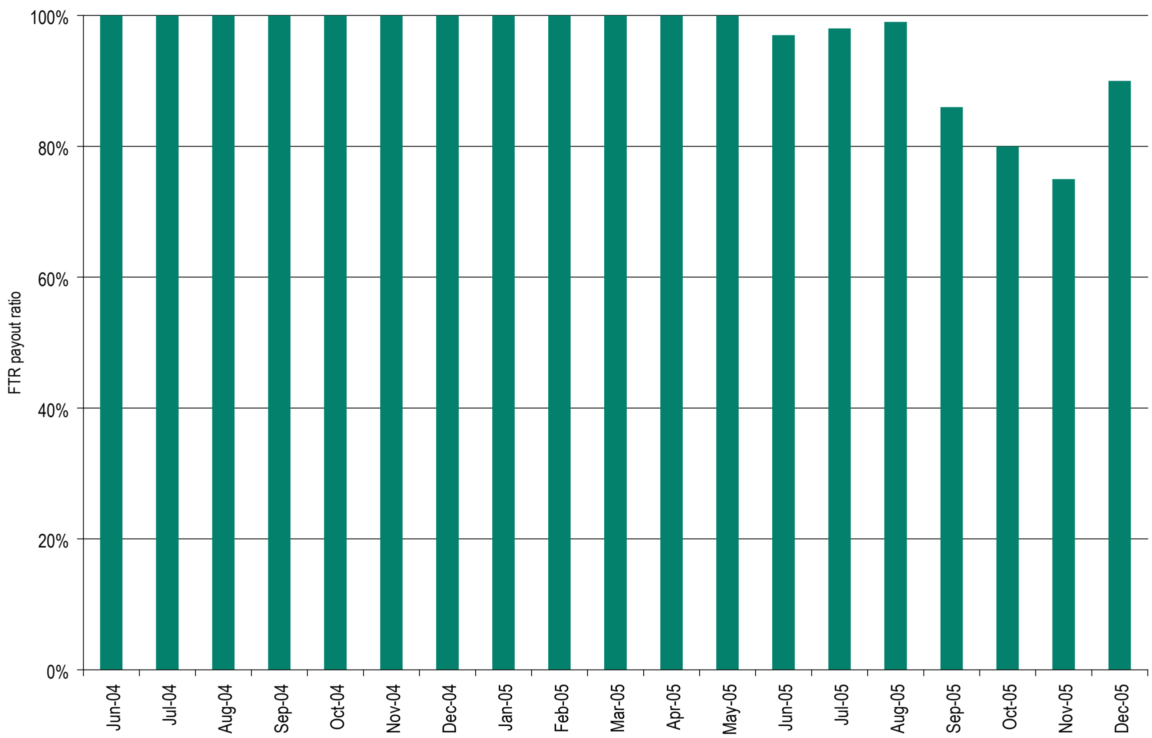
Table 8-7 - Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

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		

FTR Revenue and Congestion

FTR target allocations are based on hourly, day-ahead prices for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Figure 8-8 shows the monthly FTR payout ratio from June 2004 through December 2005.[16] FTRs were paid at 100 percent of the target allocations for the 2004 to 2005 planning period. FTRs through December 31, 2005, of the 2005 to 2006 planning period have been paid at 91 percent of the target allocation level.[17]

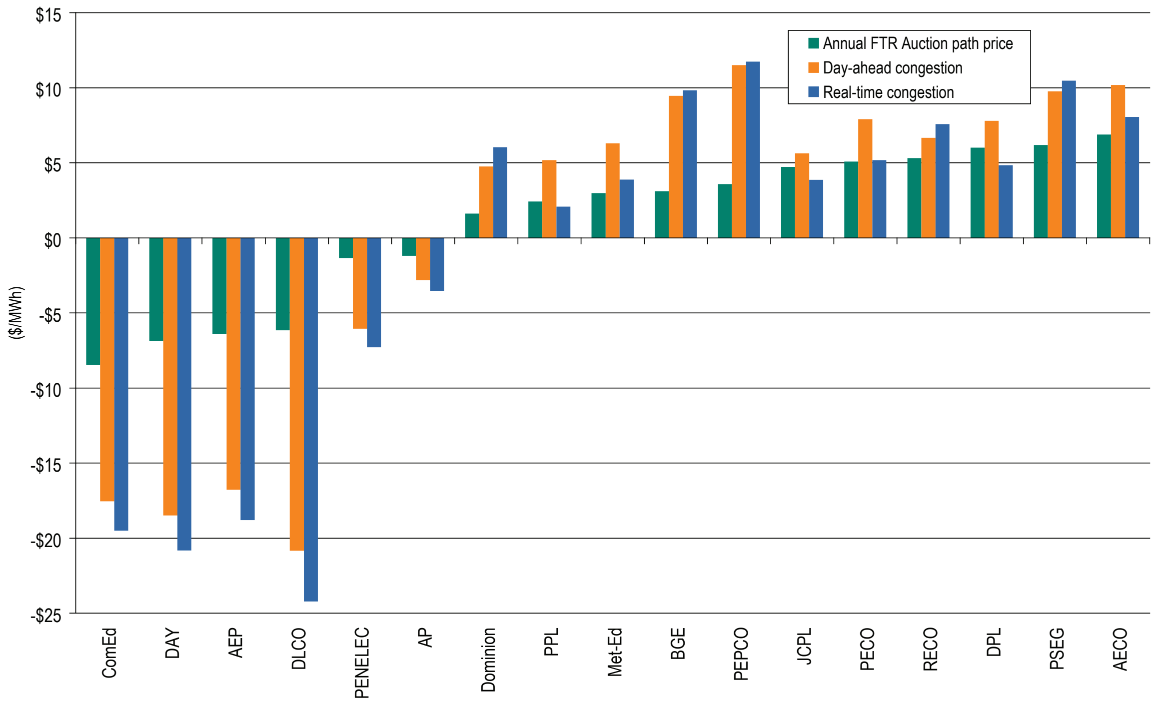
Figure 8-8 - Monthly FTR payout ratio: June 2004 to December 2005



16 See Section 7, “Congestion,” at Table 7-5, “Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period.”
17 For full congestion accounting and FTR revenue adequacy data, see Section 7, “Congestion.”

Figure 8-9 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM 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 $5.09 per MWh in the Annual FTR Auction and that about $7.91 per MWh of day-ahead congestion and $5.18 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 that are located east of Western Hub while congestion costs and price of FTRs are negative for control zones that are located west of that hub.

Figure 8-9 - Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2005 to 2006 through December 31, 2005



FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2005 to 2006 planning period through December 31, 2005. Figure 8-10 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 84.4 percent of total positive target allocations. FTRs with the top three sinks, the AEP, AP and Dominion Control Zones, included 63.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 43.4 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 11.6 percent of all negative target allocations.

Figure 8-10 - Ten largest positive and negative FTR target allocations summed by sink: Planning period 2005 to 2006 through December 31, 2005

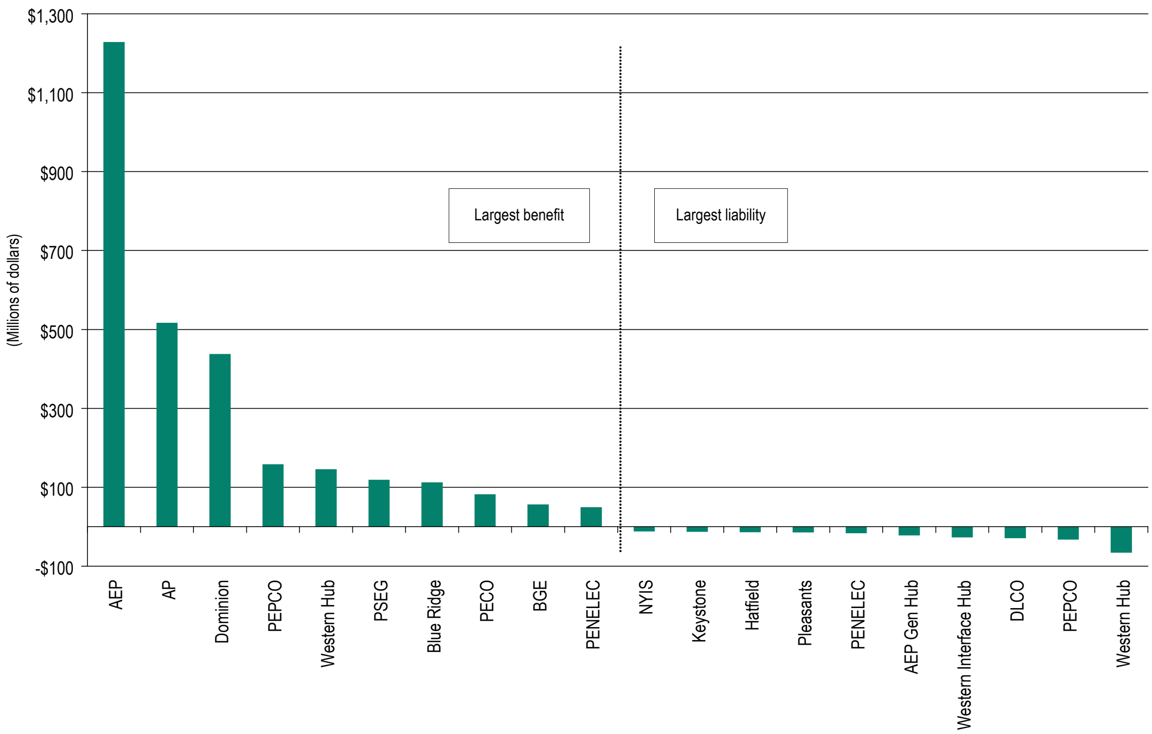
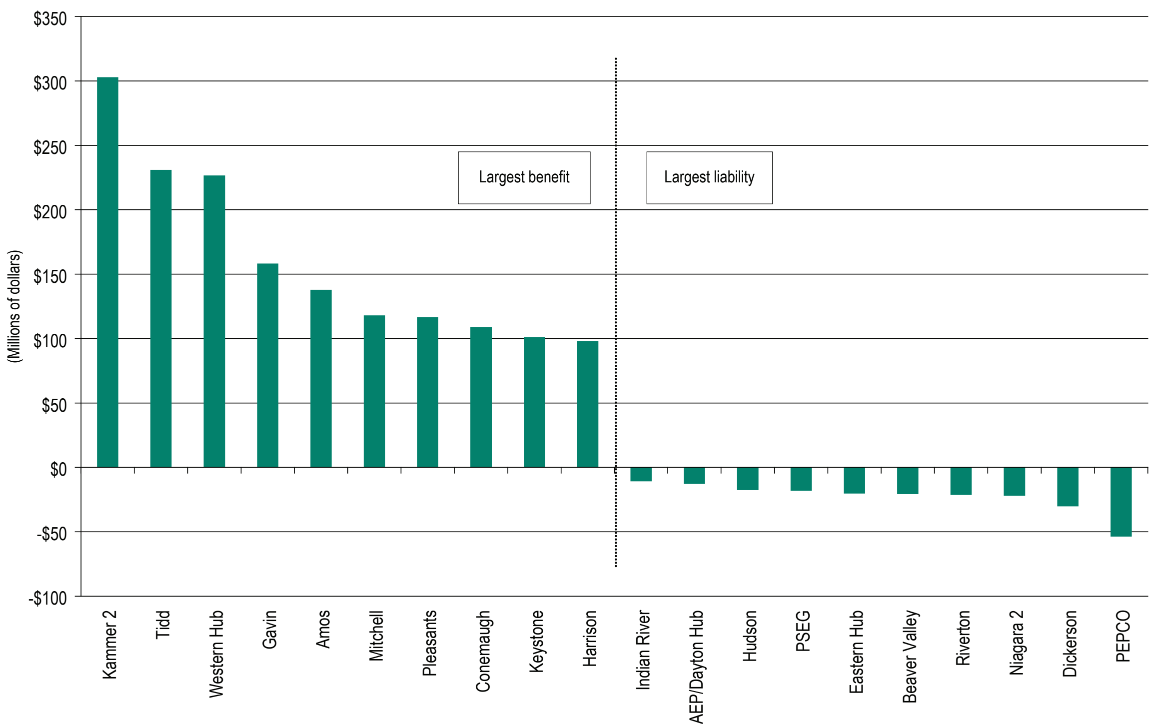


Figure 8-11 shows the FTR sources with the largest positive and negative target allocations. The top 10 sources with a positive target allocation accounted for 46.4 percent of total positive target allocations. All of these 10 sources were located in the AP and AEP Control Zones. FTRs with the Kammer 2 unit as their source included 8.8 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 40.4 percent of total negative target allocations. FTRs with the PEPCO Control Zone as the source encompassed 9.5 percent of all negative target allocations.

Figure 8-11 - Ten largest positive and negative FTR target allocations summed by source: Planning period 2005 to 2006 through December 31, 2005



Auction Revenue Rights

ARRs are financial instruments that entitle their holders to receive revenue or pay charges 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 price differences between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on these 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.

ARRs have been available to eligible participants since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and AP Control Zone. For the 2005 to 2006 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the new ComEd, AEP, DAY, DLCO and Dominion Control

Zones. After their integration dates, market participants in the new zones have two planning periods during which they are eligible for transitional allocation of FTRs or ARRs. After that transition, market participants are subject to the ARR allocation rules. When load shifts from one LSE to another in newly integrated zones, directly allocated FTRs with positive economic value follow the load.[18]

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. As of June 1, 2005, PJM had projected that its 2005 network peak load would be 126,293 MW plus an additional 6,066 MW of firm point-to-point service. Therefore, maximum ARR demand, including direct allocation FTRs for newly integrated control zones, was expected to be 132,359 MW, the sum of network and long-term, firm point-to-point transmission service.

ARR demand was 82,343 MW during the 2005 to 2006 planning period, up from 55,128 MW during the 2004 to 2005 planning period. Demand for ARRs increased because of load growth and the eligibility of the newly integrated zones to select ARR allocations, instead of direct allocation FTRs.

PJM's Open Access Transmission Tariff specifies the types of transmission service that are available to eligible customers. Eligible customers submit requests for transmission service – network and firm, point-to-point service – to PJM through the Open Access Same-Time Information System (OASIS). PJM evaluates each transmission-service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM network system. All available generating resources are included when evaluating the requested transmission services. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point services, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. Nonetheless, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated *pro rata* shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

For the 2005 to 2006 planning period, 59,410 MW of ARRs were cleared and allocated out of all the ARR requested, leaving uncleared bids of 22,933 MW. The Cedar Grove - Clifton 230 kV line and the Laurel - Woodstown 69 kV line were the principal constraints limiting supply in the Stage 1 ARR allocation. Similarly, the AP South Interface, the Branchburg 500/230 kV transformer and the Eastern Interface were the principal constraints limiting supply in the Stage 2 ARR allocation.

In response to a 2004 order by the United States Federal Energy Regulatory Commission (FERC),[19] PJM proposed changes to its ARR allocation process that would allow certain long-term, firm point-to-point transmission service customers to participate in Stage 1 of the annual ARR allocation. In a March 7, 2005,

18 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Reassignment of Financial Transmission Rights (FTRs)," Section 5, p. 32.
19 106 FERC ¶ 61,049 (2004).

order effective the following day, the FERC approved the proposed changes in the allocation rules, allowing network and point-to-point customers to participate on the same basis in the first and second stages of ARR allocation.[20] The rules were approved before the start of its Stage 1 ARR allocation process and became effective with the 2005 to 2006 planning period.

When retail load switches among LSEs, existing PJM market rules ensure that ARRs and their associated revenues are automatically reassigned from the losing to the winning LSE if the losing LSE has a net positive economic ARR value to that zone. About 10,921 MW of ARRs associated with $169,200 per MW-day of revenue were automatically reassigned in the first seven months (June 1 to December 31) of the 2005 to 2006 planning period. About 22,752 MW of ARRs with $173,600 per MW-day of revenue were reassigned for the 2004 to 2005 planning period. Any MW of load may be reassigned multiple times over a period. However, when ARRs are self-scheduled, the underlying FTR does not follow load and this may diminish the value of the hedge.

Prior to the start of the Stage 2 ARR allocation process, a participant can relinquish any portion of the ARR awards resulting from Stage 1 allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[21] Immediately after the Stage 1 ARR allocation for the 2005 to 2006 planning period, eligible customers relinquished 270 MW of the allocated ARRs. Participants may seek additional ARRs in the Stage 2 allocation.

For the set of requested ARRs, available supply was 59,410 MW. This level of ARR availability was higher than the 33,589 MW available during the 2004 to 2005 planning period, but still left 22,933 MW of ARR demand unfulfilled. The Cedar Grove - Clifton 230 kV and the Laurel - Woodstown 69 kV lines were the principal binding constraints limiting supply in the Stage 1 ARR allocation. Similarly, the AP South Interface, the Branchburg 500/230 kV transformer and the Eastern Interface were the principal binding constraints limiting supply in the Stage 2 ARR allocation.

ARR Allocation

Network service and long-term, firm point-to-point transmission customers can request ARRs up to the amount of their transmission service.[22] Network service customers may request ARRs up to their peak-load value, while qualifying firm transmission customers may request ARRs based on MW of firm service provided between receipt and delivery points for which the transmission customer had point-to-point transmission service during the reference year.[23, 24]

20 110 FERC ¶ 61,254 (2005).

21 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Annual Allocation of Auction Revenue Rights (ARRs) – Stage 1," Section 4, p. 24.

22 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.

23 Any firm transmission customers with an agreement for long-term point-to-point transmission service that is used to deliver energy from a designated network resource to load located either outside or within the PJM region, and that was confirmed and in effect during the historical reference year for the zone in which the resource is located.

24 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Annual Allocation of Auction Revenue Rights (ARRs) – Stage 1," Section 4, p. 22.

PJM allocates annual ARRs to eligible customers in a two-stage process, where the first stage is one round and second stage is a four-round allocation procedure:

- **Stage 1.** In the first stage of the allocation, network service customers can obtain ARRs, up to their peak-load share, based on generation resources that historically have served load in each transmission zone or load aggregation zone.[25] Firm point-to-point customers can obtain ARRs based on the MW of firm, long-term point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the period covered by the allocation.

- **Stage 2.** The second stage of the allocation is a four-step procedure, with 25 percent of remaining system capability allocated in each step of the process. Network service transmission customers can obtain ARRs from any generator bus, hub, zone or interface to any part of their aggregate load in the transmission zone or load aggregation zone to which an ARR was not allocated in the first stage. Firm point-to-point customers can obtain ARRs consistent with their transmission service as in Stage 1.

If the requested set of ARRs is not simultaneously feasible,[26] 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)[27]

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.[28] Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. 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.

ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can be requested through the PJM OASIS.[29]

25 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Network Integration Service Auction Revenue Rights (ARRs)," Section 3, p. 18.
26 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.
27 See Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.
28 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Allocation of Incremental Auction Revenue Rights (ARRs)," Section 4, p. 27.
29 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Firm Point-to-Point Transmission Auction Revenue Rights (ARRs)," Section 3, p. 19.

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.[30] 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. However, in the case where an LSE has elected to self-schedule ARRs, the positively valued ARRs follow load but the underlying FTRs do not.

Table 8-8 - ARRs automatically reassigned for network load changes by control zone (MW-day): June 1, 2004, to December 31, 2005

	2004/2005 (12 Months)	2005/2006 (7 Months)*
AECO	181	491
AEP	94	213
AP	188	181
BGE	4,383	2,608
ComEd	3,288	2,390
DAY	48	3
DLCO	364	467
Dominion	0	74
DPL	2,461	112
JCPL	784	1,000
Met-Ed	108	79
PECO	830	346
PENELEC	73	77
PEPCO	8,507	2,030
PPL	219	55
PSEG	1,206	791
RECO	18	4
Total	22,752	10,921

* Through 31-Dec-05

30 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Reassignment of Auction Revenue Rights (ARRs)," Section 4, p. 26.

Table 8-8 and Table 8-9 summarize ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2004 and December 2005. For the first seven months (June 1 to December 31) of the 2005 to 2006 planning period, more than 10,900 MW of ARRs were automatically reassigned, generating about $169,200 per MW-day of revenue.

Table 8-9 - ARR revenue automatically reassigned for network load changes by control zone [Dollars (thousands) per MW-day]: June 1, 2004, to December 31, 2005

	2004/2005 (12 Months)	2005/2006 (7 Months)*
AECO	$4.3	$16.2
AEP	$0.0	$4.9
AP	$0.0	$21.3
BGE	$41.7	$39.4
ComEd	$0.1	$7.9
DAY	$0.0	$0.0
DLCO	$0.0	$3.0
Dominion	$0.0	$0.0
DPL	$34.5	$1.8
JCPL	$10.9	$18.8
Met-Ed	$1.3	$2.2
PECO	$15.3	$13.0
PENELEC	$2.0	$1.6
PEPCO	$29.2	$15.2
PPL	$2.0	$1.2
PSEG	$32.3	$22.7
RECO	$0.0	$0.0
Total	$173.6	$169.2

* Through 31-Dec-05

ARRs and Integrations

Transitional FTR Allocation

During any planning period when new control zones are being integrated, PJM directly allocates FTRs to eligible customers in those zones.[31] 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 8-1 summarizes eligibility for ARRs and direct allocation FTRs.

Congestion Mitigation Credits

In response to the March 12, 2003, FERC order addressing direct assignment of FTRs for load in new zones as they are added to PJM,[32] PJM made a compliance filing[33] providing members in newly integrated zones the choice of receiving a direct allocation of FTRs or an allocation of FTRs for the two succeeding Annual FTR Auctions following the integration of the new zone into the PJM Energy Market.

In a related January 28, 2004, order,[34] the FERC required PJM to amend its tariff and file its proposed allocation method under section 205 of the Federal Power Act (FPA). The FERC also required that, if PJM could not award FTRs to all existing firm point-to-point customers, it would have to justify why the resulting allocation was reasonable and why mitigating measures should not be adopted.

The FERC found that since the allocation process gave preference to network service customers, PJM's annual allocation process for FTRs and ARRs under its existing Tariff and Operating Agreement appeared to be unjust and unreasonable under section 206 of FPA and instituted procedures to determine a just and reasonable allocation process for succeeding years.[35]

In responding, PJM acknowledged that its two-stage allocation process included a preference for native load customers served from resources that had historically served their load.[36]

PJM submitted a January 7, 2005, filing[37] in which PJM proposed to permit firm point-to-point customers to obtain FTRs/ARRs on a comparable basis to network customers for historic resources in the first stage of the allocation. After clarification on March 7, 2005, order and subsequent clarification on May 9, 2005, the FERC accepted PJM's proposal that permits point-to-point customers to obtain FTRs/ARRs on a comparable basis to network customers for nonhistoric resources in the second stage of the allocation.

The FERC ordered that if long-term, firm point-to-point transmission customers in the ComEd and AEP Control Zones were not allocated their full ARRs or FTR requests 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.

31 "PJM Financial Transmission Rights Manual" (April 15, 2005), "FTR Allocation Process for New Load in Zones Associated with Market Growth," Section 5, p. 29.
32 102 FERC ¶ 61,276 (2003).
33 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket No. ER03-406-002 (April 11, 2003, amended April 22, 2003).
34 106 FERC ¶ 61,049 (2004).
35 107 FERC ¶ 61,223 (2004) at P 47.
36 *Id* at P 15.
37 *PJM Interconnection, L.L.C.,* Compliance Filing, Docket Nos. ER04-742-003 and EL04-105-001 (January 7, 2005).

Total credit costs for these unallocated ARRs or FTRs 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, Table 8-10 summarizes FTRs requested by and awarded to customers in the relevant control zones, including mitigation FTRs.

Table 8-10 - ComEd and AEP Control Zones FTR mitigation credits: Planning period 2004 to 2005

	FTR Requested (MW)	FTR Awarded (MW)	FTR Unallocated (MW)	Requested FTR as Percent Unallocated
ComEd	476	308	168	35%
AEP	1,005	51	954	95%
Total	1,481	359	1,122	76%

Congestion mitigation credits for the ComEd and AEP Control Zones were valid only for the 2004 to 2005 planning period's FTR Market, ending May 31, 2005. During the 2005 to 2006 planning period, no mitigation credit is required for these integrated zones because long-term, firm point-to-point transmission customers can participate in the Stage 1 ARR allocation on an equal footing with network service transmission customers.

Pursuant to section 205 of the FPA, PJM's September 1, 2004, compliance filing with the FERC proposed an initial allocation of FTRs for the Dominion Control Zone, starting from its then planned November 1, 2004, integration date.[38] The FERC order found that under PJM's allocation, 100 percent of all FTRs requested for the Dominion Control Zone in Stage 1 were awarded.[39] Similarly, in the Stage 2 allocation, no ARRs requested by firm point-to-point transmission service customers had to be prorated. Thus, unlike the FTR allocation process for the ComEd and AEP Control Zones, the FERC agreed with PJM that no mitigation was necessary in this case.[40]

According to the FERC order mentioned above, a mechanism for congestion mitigation credit for Dominion Control Zone was not required.

ARR Performance

Volume

Of 82,343 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW (72 percent) were allocated. Eligible market participants subsequently converted 32,631 MW of these allocated ARRs into annual FTRs (55 percent of total allocated ARRs), leaving 26,779 MW of ARRs outstanding. Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW (61 percent) were allocated, of which 13,061 or 39 percent were converted into FTRs.

38 Dominion joined PJM on May 1, 2005.

39 The FERC notes that according to PJM, the only FTR requests that were prorated in this allocation were from two network service users that sought additional FTRs to resources that were perceived to have higher value [109 FERC ¶ 61,075 (2004) at P 17].

40 109 FERC ¶ 61,075 (2004) at P 17.

Revenue

Any ARR credits received equal the product of the ARR MW and the sink-minus-source price difference for the ARR path 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[41] has a hedge value based on actual day-ahead congestion on the selected path rather than a hedge value based on what bidders pay in the Annual FTR Auction.

ARR holders will receive $870 million in credits from the Annual FTR Auction during the 2005 to 2006 planning period, with an average hourly ARR credit of $1.67 per MWh. During the comparable 2004 to 2005 planning period, ARR holders received $345 million in ARR credits, with an average hourly ARR credit of $1.17 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 price differences between ARR sink and source established during the Annual FTR Auction. FTR Auction revenue is the net revenue from the auction. All ARR holders receive ARR credits equal to their target allocations if total net Annual and Monthly FTR Auction revenues are greater than, or equal to, the sum of all ARR target allocations. If the combined net Annual and Monthly FTR Auction revenues are less than that, the available revenue is proportionally allocated among all ARR holders.

Table 8-11 lists ARR target allocations and net revenue sources from the Annual and Monthly FTR Auctions for the 2003 to 2004, the 2004 to 2005 and the 2005 to 2006 (through December 31, 2005) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for all three planning periods. The 2005 to 2006 planning period's Annual and Monthly FTR Auctions generated a surplus of $22 million in auction net revenue through December 31, 2005, above the amount needed to pay 100 percent of ARR target allocations.

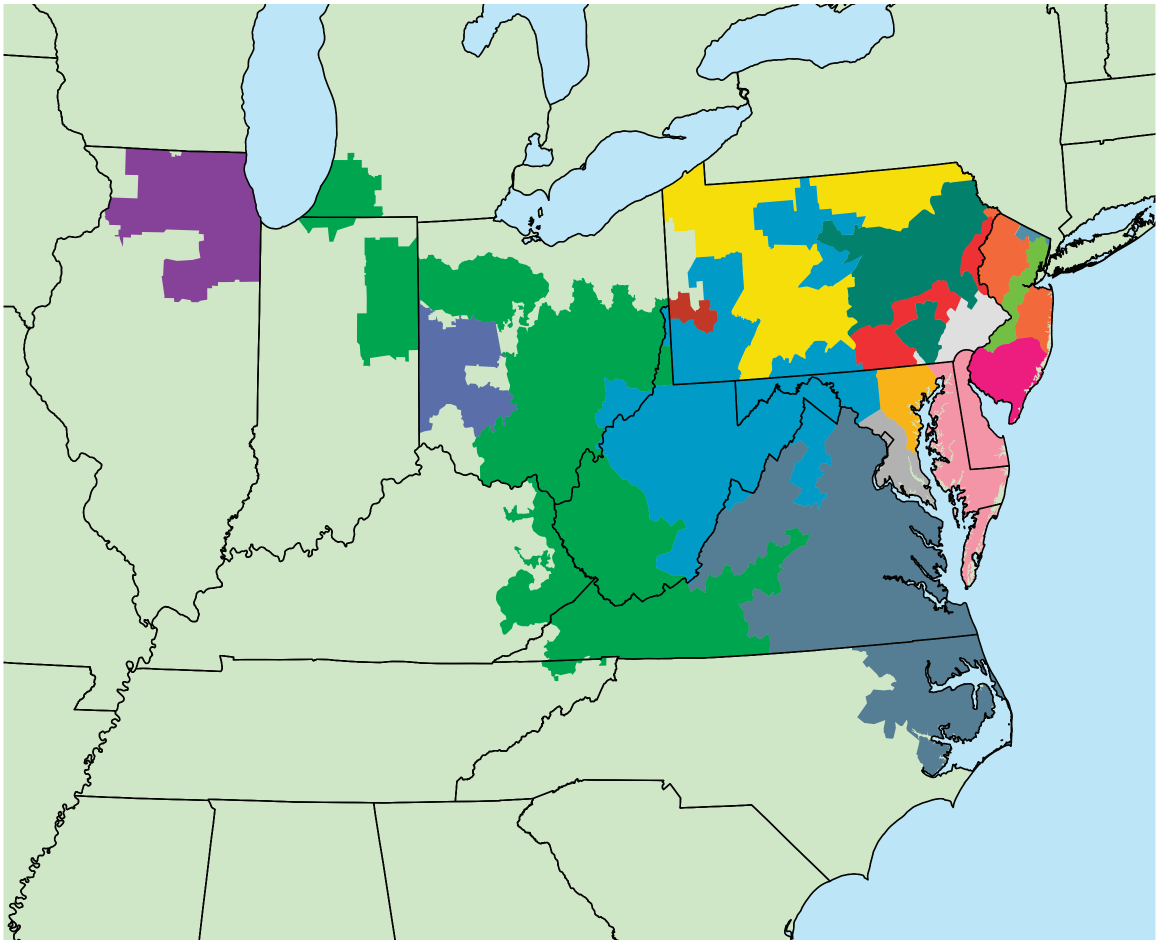
Table 8-11 - ARR revenue adequacy [Dollars (millions)]: By planning period

	2003/2004	2004/2005	2005/2006
Total FTR Auction Net Revenue	$359	$385	$892
Annual FTR Auction Net Revenue	$333	$370	$882
Monthly FTR Auction Net Revenue*	$26	$15	$10
ARR Target Allocations	$311	$345	$870
ARR Credits	$311	$345	$870
Surplus Auction Revenue	$48	$40	$22
ARR Payout Ratio	100%	100%	100%

* Shows 17 months for 2003/2004, 12 months for 2004/2005 and 7 months ending 31-Dec-05 for 2005/2006

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

APPENDIX A – PJM SERVICE TERRITORY



Legend

ZONE

- Allegheny Power Systems
- American Electric Power Co., Inc
- Atlantic Electric Company
- Baltimore Gas and Electric Company
- ComEd
- Dayton Power and Light Company
- Delmarva Power and Light
- Dominion
- Duquesne Light
- Jersey Central Power and Light Company
- Metropolitan Edison Company
- PPL Electric Utilities
- PECO Energy
- 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, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market clearing prices
	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
	March	FERC approval of Market Monitoring Plan
	April	Offer-based 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 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
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM