Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and which creates the funds available to offset congestion costs in an LMP market.[2]

The *2013 State of the Market Report for PJM*, focuses on the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period, covering January 1, 2013, through December 31, 2013.

Table 13-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and over sells FTRs. FTR funding levels are reduced as a result of these and other factors.

1 See 81 FERC ¶ 61,257, at 62,241 (1997).
2 See Id. at 62, 259–62,260 & n. 123.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2014 to 2017 Long Term FTR Auction include the Monticello – East Winamac flowgate, approximately 120 miles north of Indianapolis, IN, and the Cumberland Ave - Bush flowgate, approximately 100 miles north of Indianapolis, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2013 to 2014 planning period include the Cumberland Ave – Bush flowgate, approximately 100 miles north of Indianapolis, IN and the Beaver Channel - Albany flowgate, approximately 100 miles north of Springfield, IL. The geographic location of these constraints is shown in Figure 13-1.
- **Market participants can also sell FTRs.** In the 2014 to 2017 Long Term FTR Auction, total participant FTR sell offers were 316,056 MW, up from 211,316 MW from the 2013 to 2016 Long Term FTR Auction. In the 2013 to 2014 Annual FTR Auction, total participant FTR sell offers were 417,118 MW, up from 356,299 MW in the 2012 to 2013 planning period. In the first seven months of the Monthly Balance of Planning Period FTR Auctions for the

2013 to 2014 planning period, total participant FTR sell offers were 3,862,503 MW, up from 3,589,824 MW for the same period during the 2012 to 2013 planning period.

- **Demand.** In the 2014 to 2017 Long Term FTR Auction, total FTR buy bids increased 10.8 percent from 2,772,621 MW to 3,072,909 MW. There were 3,274,373 MW of buy and self-scheduled bids in the 2013 to 2014 Annual FTR Auction, up from 2,561,835 MW in the previous planning period. The total FTR buy bids from the first seven months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 11.4 percent from 14,906,684 MW for the same time period of the prior planning period, to 16,604,063 MW.

- **Patterns of Ownership.** For the 2014 to 2017 Long Term FTR Auction, financial entities purchased 65.1 percent of prevailing flow FTRs and 79.7 percent of counter flow FTRs. For the 2013 to 2014 Annual FTR Auction, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 76.0 percent of prevailing flow and 85.8 percent of counter flow FTRs for January through December of 2013. Financial entities owned 59.0 percent of all prevailing and counter flow FTRs, including 50.6 percent of all prevailing flow FTRs and 75.3 percent of all counter flow FTRs during January through December 2013.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $531,678 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.

- **Credit Issues.** Ten participants defaulted during 2013 from 16 default events. The average of these defaults was $255,611 with 10 based on inadequate collateral and six based on nonpayment. The average collateral default was $93,749 and the average nonpayment default was $352,729. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** The 2014 to 2017 Long Term FTR Auction cleared 197,125 MW (6.4 percent of demand) of FTR buy bids, compared to 290,700 MW (10.5 percent) in the 2013 to 2015 Long Term FTR Auction. This is at least partially due to the newly implemented rule limiting Long Term FTR Auction capacity to 50 percent. The Long Term FTR Auction also cleared 21,501 MW (6.8 percent) of FTR sell offers, down from 56,692 MW (26.8 percent) in the 2013 to 2014 Long Term FTR Auction.

  In the Annual FTR Auction for the 2013 to 2014 planning period 420,489 MW (12.8 percent) of buy and self-schedule bids cleared. For the first seven months of the 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 2,283,411 MW (13.8 percent) of FTR buy bids and 742,731 MW (19.2 percent) of FTR sell offers.

- **Price.** In the 2014 to 2017 Long Term FTR Auction, 97.6 percent of FTRs were purchased for less than $1 per MW, up from 95.9 percent in the previous Long Term FTR Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction was -$0.18, down from $0.36 from the previous Long Term FTR Auction.

  For the 2013 to 2014 annual auction, 93.0 percent of FTRs were purchased for less than $1 per MW, up from 93.0 percent in the previous Annual FTR Auction. The weighted-average buy-bid FTR price for the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2013 to 2014 planning period was $0.06, down from $0.12 per MW in the 2012 to 2013 planning period.

- **Revenue.** The 2014 to 2017 Long Term FTR Auction generated $16.8 million of net revenue for all FTRs, down from $28.6 million in the 2013 to 2016 Long Term FTR Auction. The 2013 to 2014 Annual FTR Auction generated $558.4 million in net revenue, down $44.5 million from the 2012 to 2013 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $5.4 million in net revenue for all FTRs for the first seven months of the 2013 to 2014 planning period, down from $17.3

million for the same time period in the 2012 to 2013 planning period.

- **Revenue Adequacy.** FTRs were paid at 67.8 percent of the target allocation for the entire 2012 to 2013 planning period. FTRs were paid at 75.1 percent of the target allocation level for the first seven months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the first seven months of the 2013 to 2014 planning period and $614.0 million during the entire 2012 to 2013 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Sunnymead and the Western Hub.

  Target allocations values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs.

- ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $170.2 million in profits for physical entities, of which $167.9 million was from self-scheduled FTRs, and $177.5 million for financial entities. As shown in Table 13-18, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013. FTR profits generally increased in the summer and winter months when congestion was higher.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the annual ARR allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the annual ARR allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the first seven months of the 2013 to 2014 planning period PJM allocated a total of 6,428.8 MW of residual ARRs with a total target allocation of $3,647,248.

- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 35,501 MW of ARRs associated with approximately $233,800 of revenue that were reassigned for the first seven months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first seven months of the 2013 to 2014 planning period, the ARR target allocations were $175.0 million while PJM collected $197.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $587.0 million while PJM collected $653.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first seven months of the

2013 to 2014 planning period and for the 2012 to 2013 planning period.

Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested. One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system as a hedge against congestion and pay for balancing congestion in order to increase the payout to holders of FTRs who are not loads.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period, the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013, the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM monthly is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real–time markets, including reactive interfaces, which directly results in differences in congestion between day - ahead and real-time markets; differences in day-ahead and real–time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day–ahead and real-time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, PJM should reduce the number of FTRs sold.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths, subject to revenue availability. This value, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses.

Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation is a cap on what FTR holders can receive. Revenues above that level on individual FTR paths are used to fund FTRs on paths which received less than their target allocations. Available revenue to pay FTR holders is based on the amount of day-ahead and balancing congestion collected, along with Market to Market payments, excess ARR revenues available at the end of a month and any charges made to day-ahead operating reserves.

FTR funding is not on a path specific basis or on a time specific basis. There are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. Revenues to fund FTRs come from both day-ahead congestion charges on the transmission system and balancing congestion charges. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self-scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR 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) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates an Annual FTR Auction for all participants. In addition, PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, which allows participants to buy and sell residual transmission capability. PJM also runs a Long Term FTR Auction for the following three consecutive planning years. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

FTR buy bids and sell offers may be made as obligations or options and as any of the three classes. FTR self-scheduled bids are available only as obligations and 24-hour class, consistent with the associated ARRs, and only in the Annual FTR Auction.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[3] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction.

Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included in the model, while known outages of five days or more are included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[4]

But the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR.

Long Term FTR Auctions

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system

3 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 38.
4 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 55.

capability assuming that all ARRs allocated in the prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds.[5] The 2011 to 2014 and 2012 to 2015 Long Term FTR Auctions consisted of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one year or a single term of all three years. FTR products available in the Long Term Auction include 24-hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 1.** The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink.
- **Round 2.** The second round is conducted approximately three months after the first round and follows the same rules as Round 1.
- **Round 3.** The third round is conducted approximately six months after the first round and follows the same rules as Round 1.

Table 13-2 and Table 13-3 show the top 10 binding constraints for the 2014 to 2017 Long Term FTR Auction and the 2013 to 2014 Annual FTR Auction based on the marginal value of on peak hours. The severity ranking is based on the marginal value of the constraint in the simultaneous feasibility test.

Table 13-2 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2014 to 2017

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
Monticello - East Winamac	Flowgate	MISO	1	58	1
Cumberland Ave - Bush	Flowgate	MISO	10	1	2
West Lafayette - Cumberland	Flowgate	MISO	NA	2	16
Oak Grove - Galesburg	Flowgate	MISO	NA	11	3
Bartonsville - Stephenson	Line	AP	NA	NA	4
Mazon - Mazon	Line	ComEd	264	10	5
Cayuga	Line	Penelec	4	3	9
Commonwealth NG - Grassfields	Line	Dominion	5	NA	NA
New Carlisle - Map	Line	MISO	NA	4	NA
Gordonsville	Transformer	Dominion	6	143	NA

Annual FTR Auctions

After the Long Term FTR Auction, residual capability on the PJM transmission system is auctioned in the Annual FTR Auction. Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months are included in the determination of the simultaneous feasibility for the Annual FTR Auction. ARR holders who wish to self schedule must inform PJM prior to round one of this auction. Any self-scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24-hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Figure 13-1 shows the geographic location of the top ten binding constraints from the 2014 to 2017 Long Term FTR Auction, the 2013 to 2014 Annual FTR Auction and the 2013 to 2014 Annual ARR allocation. Many of the top binding constraints are flowgates and the binding constraints are primarily concentrated near the PJM-MISO border. All of the top Long Term FTR Auction constraints are also ARR constraints, denoted by a yellow border.

5 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

Figure 13-1 Geographic location of top five binding constraints for the Long Term FTR Auction, Annual FTR Auction and Annual ARR Allocation: Planning period 2014 to 2017 and 2013 to 2014

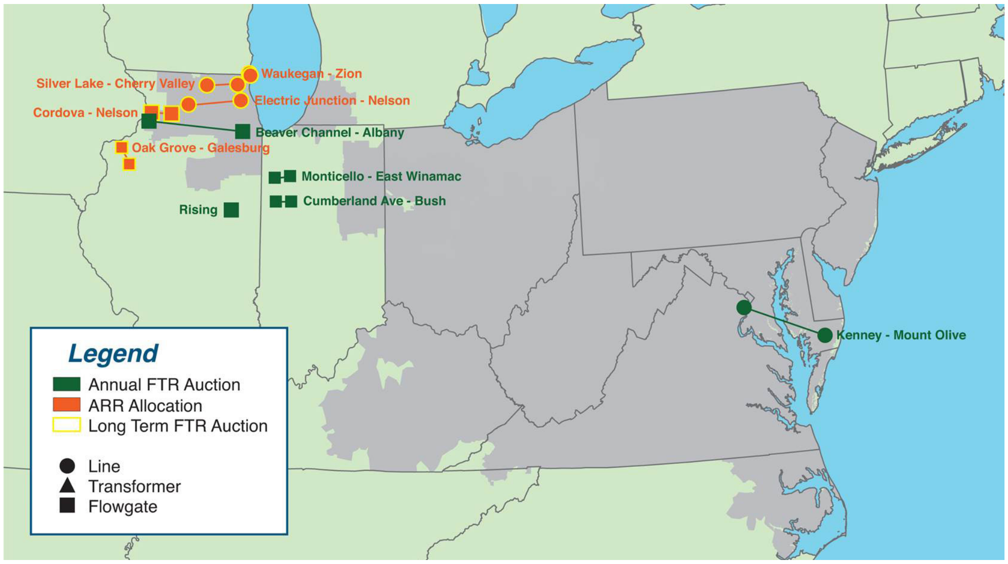


Table 13-3 shows the top 10 binding constraints for the 2013 to 2014 Annual FTR Auction based on the marginal value of on peak hours.

Table 13-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2013 to 2014

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Cumberland Ave - Bush	Flowgate	MISO	1	1	1	1
Beaver Channel - Albany	Flowgate	MISO	2	3	2	3
Monticello - East Winamac	Flowgate	MISO	3	2	3	2
Rising	Flowgate	MISO	NA	NA	NA	4
Kenney - Mount Olive	Line	DPL	7	NA	4	5
Roxbury - Shade Gap	Line	PENELEC	4	8	8	10
Prairie State - W. Mt. Vernon	Flowgate	MISO	5	5	10	NA
Glenarm - Windy Edge	Line	BGE	6	7	5	6
Kenney - Stockton	Line	DPL	NA	4	NA	NA
Pana North	Flowgate	MISO	8	6	6	NA

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Existing FTRs are modeled as fixed injections and withdrawals. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak and off peak products.[6]

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original

6 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 39.

FTR start time and the end time cannot be later than the original FTR end time.

Buy Bids

The total FTR buy bids in the 2013 to 2014 Annual FTR Auction were 3,274,373 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period were 19,685,688 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-4 presents the 2014 to 2017 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 65.1 percent of prevailing flow by bid FTRs and 79.7 percent of counter flow buy bid FTRs with the result that financial entities purchased 70.7 percent of all Long Term FTR Auction cleared buy bids for the 2014 to 2017 Long Term FTR Auction.

Table 13-4 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2014 to 2017

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	34.9%	20.3%	29.3%
	Financial	65.1%	79.7%	70.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	13.0%	13.0%	13.0%
	Financial	87.0%	87.0%	87.0%
	Total	100.0%	100.0%	100.0%

Table 13-5 presents the Annual FTR Auction cleared FTRs for the 2013 to 2014 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2013 to 2014 planning period, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs, with the result that financial entities purchased 61.5 percent of all Annual FTR Auction cleared buy bids for the 2013 to 2014 planning period.

Table 13-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2013 to 2014

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	9.2%	0.2%	7.0%
		No	36.1%	17.5%	31.5%
		Total	45.3%	17.8%	38.5%
	Financial	No	54.7%	82.2%	61.5%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		20.7%	19.0%	20.2%
	Financial		79.3%	81.0%	79.8%
	Total		100.0%	100.0%	100.0%

Table 13-6 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through December 2013 by trade type, organization type and FTR direction. Financial entities purchased 76.0 percent of prevailing flow and 85.8 percent of counter flow FTRs for the year, with the result that financial entities purchased 80.0 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through December 2013.

Table 13-6 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through December 2013

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	24.0%	14.2%	20.0%
	Financial	76.0%	85.8%	80.0%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	31.7%	28.6%	31.1%
	Financial	68.3%	71.4%	68.9%
	Total	100.0%	100.0%	100.0%

Table 13-7 presents the daily net position ownership for all FTRs for January through December 2013, by FTR direction.

Table 13-7 Daily FTR net position ownership by FTR direction: January through December 2013

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	49.4%	24.7%	41.0%
Financial	50.6%	75.3%	59.0%
Total	100.0%	100.0%	100.0%

Market Behavior

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real-time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 13-2 demonstrates the FTR forfeiture rule for INCs and DECs. The INC or DEC distribution factor (dfax) is compared to the largest impact withdrawal or injection dfax. If the absolute difference between the virtual bid and its counterpart is greater than or equal to 75 percent, the virtual bid is considered for forfeiture. This is the metric in the rule which defines the impact of the virtual bid on the constraint.

In the first part of the example in Figure 13-2, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfaxes is -0.75 (0.25 minus -0.5). The absolute value is 0.75. In the second part of the example in, the DEC has dfax of 0.5 and the maximum injection dfax on the constraint is -0.25. The difference between the two dfaxes is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-2 Illustration of INC/DEC FTR forfeiture rule

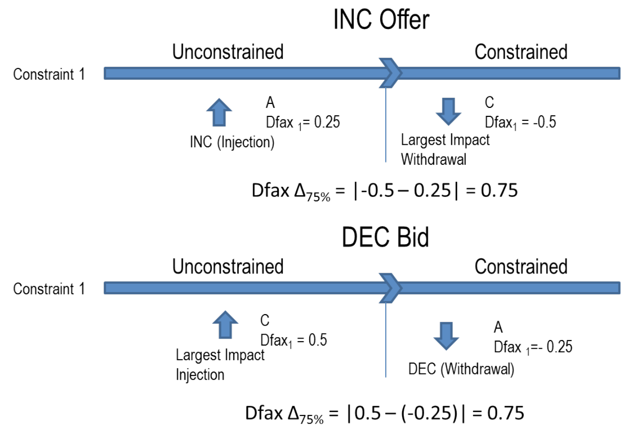


Figure 13-3 shows the FTR forfeitures values for both physical and financial participants for each month of June 2010 through December 2013. Currently, FTRs that alleviate a constraint are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2012 to 2013 planning period were $539,580 (0.09 percent of total FTR target allocations).

Figure 13-3 Monthly FTR forfeitures for physical and financial participants: June 2010 through December 2013

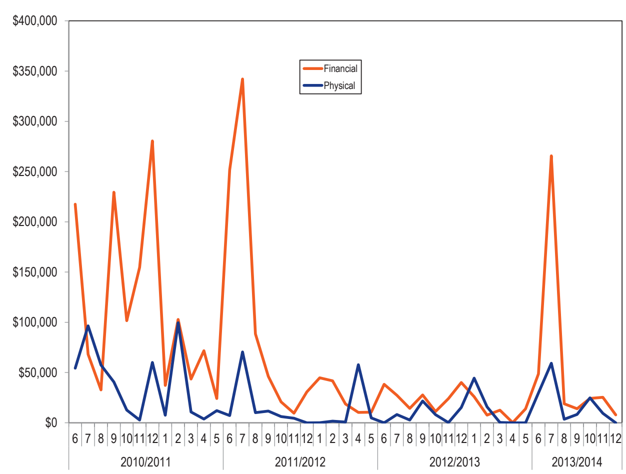
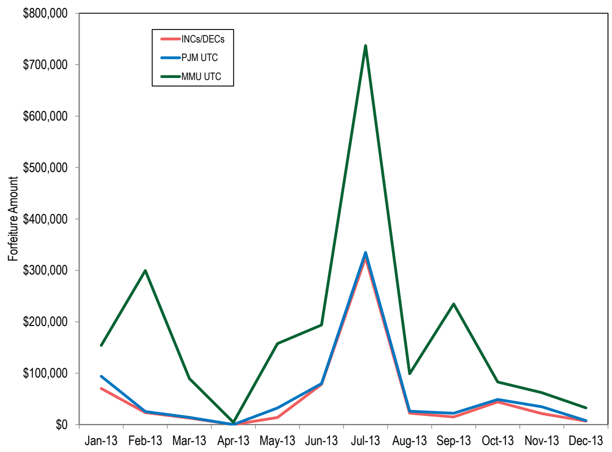


Figure 13-4 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through December 2013. The method proposed by PJM for calculating forfeitures associated with UTCs was implemented on September 1, 2013, and for each month thereafter. UTC forfeitures before September 2013 were not billed, but are included to illustrate the impact of the different methods of calculating forfeitures. The UTC curves include all forfeitures for the month associated with INCs, DECs and UTCs.

Figure 13-4 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2013



Credit Issues

The credit issues reported here were not necessarily related to FTR positions.

Ten participants defaulted during 2013 from 16 default events. The average of these defaults was $255,611 with ten based on inadequate collateral and six based on nonpayment. The average collateral default was $93,749 and the average nonpayment default was $352,729. The majority of these defaults were promptly cured, with one partial cure.

Market Performance

Volume

Table 13-8 shows the 2014 to 2017 Long Term FTR Auction volume by trade type, FTR direction and period type.[7] The total volume was 3,072,909 MW for FTR buy bids and 316,056 MW for FTR sell offers in the 2014 to 2017 Long Term FTR Auction. This represents a 23.8 percent increase in buy bids and a 104.4 percent increase in FTR sell offers over the 2012 to 2015 Long Term FTR Auction.

The 2014 to 2017 Long Term FTR Auction cleared 197,125 MW (6.4 percent) of FTR buy bids, compared to 290,700 MW (10.5 percent) in the previous Long Term FTR Auction. The 2014 to 2017 Long Term FTR Auction also cleared 21,501MW (6.8 percent) of FTR sell offers, compared to 56,692 MW (26.8 percent) in the previous Long Term FTR Auction.

The volume of buy bids for the period covering all three years of the Long Term FTR Auction was 35,019 MW for both prevailing and counter flow FTRs, with a total of 3,197 MW clearing (9.1 percent). In the previous Long Term FTR Auction the buy bids for the three year FTR were 49,019 MW with 2,400 MW clearing, representing a 28.6 percent decrease in buy bids for the 2014 to 2017 planning periods.

In the 2014 to 2017 Long Term FTR Auction 76,703 MW (5.8 percent of demand; 38.9 percent of total FTR volume) of counter flow FTR buys bids and 120,421 MW (6.8 percent of demand; 61.1 percent of total FTR volume) of prevailing flow FTR buy bids cleared. In the 2014 to 2017 Long Term FTR Auction, there were 210,794 MW (2.4 percent) of counter flow sell offers and 105,262 MW (15.7 percent) of prevailing flow sell offers cleared.

7 Calculated values shown in Section 13, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 13-8 Long Term FTR Auction market volume: Planning period 2014 to 2017

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	98,411	526,986	27,349	5.2%	499,636	94.8%
		Year 2	85,834	385,003	22,845	5.9%	362,158	94.1%
		Year 3	79,639	367,513	23,312	6.3%	344,201	93.7%
		Year All	7,078	35,019	3,197	9.1%	31,822	90.9%
		Total	270,962	1,314,520	76,703	5.8%	1,237,817	94.2%
	Prevailing Flow	Year 1	104,304	668,739	44,052	6.6%	624,687	93.4%
		Year 2	89,178	545,049	38,446	7.1%	506,603	92.9%
		Year 3	82,292	509,847	36,862	7.2%	472,984	92.8%
		Year All	7,149	34,753	1,061	3.1%	33,693	96.9%
		Total	282,923	1,758,389	120,421	6.8%	1,637,967	93.2%
	Total		553,885	3,072,909	197,125	6.4%	2,875,785	93.6%
Sell offers	Counter Flow	Year 1	37,482	112,049	2,900	2.6%	109,149	97.4%
		Year 2	26,215	76,173	1,831	2.4%	74,342	97.6%
		Year 3	11,484	22,571	286	1.3%	22,285	98.7%
		Year All	NA	NA	NA	NA	NA	NA
		Total	75,181	210,794	5,017	2.4%	205,777	97.6%
	Prevailing Flow	Year 1	19,598	64,957	9,111	14.0%	55,846	86.0%
		Year 2	13,012	34,903	6,798	19.5%	28,105	80.5%
		Year 3	3,057	5,403	575	10.6%	4,828	89.4%
		Year All	NA	NA	NA	NA	NA	NA
		Total	35,667	105,262	16,484	15.7%	88,778	84.3%
	Total		110,848	316,056	21,501	6.8%	294,555	93.2%

Table 13-9 provides the Annual FTR Auction market volume for the 2013 to 2014 planning period. Total FTR buy bids were 3,274,373 MW, up 27.8 percent from 2,561,835 MW for the previous planning period. For the 2013 to 2014 planning period 391,148 MW (12.1 percent) of buy bids cleared, up 5.3 percent from 371,295 MW for the last planning period. There were 417,118 MW of sell offers with 37,821 MW (9.1 percent) clearing for the 2013 to 2014 planning period.

Table 13-9 Annual FTR Auction market volume: Planning period 2013 to 2014

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	76,647	365,441	103,814	28.4%	261,627	71.6%
		Prevailing Flow	234,724	1,650,737	225,006	13.6%	1,425,731	86.4%
		Total	311,371	2,016,178	328,820	16.3%	1,687,358	83.7%
	Options	Counter Flow	172	8,829	0	0.0%	8,829	100.0%
		Prevailing Flow	42,659	1,220,026	62,328	5.1%	1,157,698	94.9%
		Total	42,831	1,228,855	62,328	5.1%	1,166,527	94.9%
	Total	Counter Flow	76,819	374,269	103,814	27.7%	270,455	72.3%
		Prevailing Flow	277,383	2,870,763	287,334	10.0%	2,583,430	90.0%
		Total	354,202	3,245,033	391,148	12.1%	2,853,885	87.9%
Self-scheduled bids	Obligations	Counter Flow	129	231	231	100.0%	0	0.0%
		Prevailing Flow	2,847	29,110	29,110	100.0%	0	0.0%
		Total	2,976	29,341	29,341	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	76,776	365,672	104,045	28.5%	261,627	71.5%
		Prevailing Flow	237,571	1,679,847	254,116	15.1%	1,425,731	84.9%
		Total	314,347	2,045,518	358,161	17.5%	1,687,358	82.5%
	Options	Counter Flow	172	8,829	0	0.0%	8,829	100.0%
		Prevailing Flow	42,659	1,220,026	62,328	5.1%	1,157,698	94.9%
		Total	42,831	1,228,855	62,328	5.1%	1,166,527	94.9%
	Total	Counter Flow	76,948	374,500	104,045	27.8%	270,455	72.2%
		Prevailing Flow	280,230	2,899,873	316,444	10.9%	2,583,430	89.1%
		Total	357,178	3,274,373	420,489	12.8%	2,853,885	87.2%
Sell offers	Obligations	Counter Flow	36,423	144,023	11,356	7.9%	132,667	92.1%
		Prevailing Flow	54,723	262,545	25,761	9.8%	236,784	90.2%
		Total	91,146	406,568	37,117	9.1%	369,451	90.9%
	Options	Counter Flow	1	1	0	0.0%	1	100.0%
		Prevailing Flow	406	10,549	704	6.7%	9,845	93.3%
		Total	407	10,550	704	6.7%	9,846	93.3%
	Total	Counter Flow	36,424	144,024	11,356	7.9%	132,668	92.1%
		Prevailing Flow	55,129	273,095	26,465	9.7%	246,630	90.3%
		Total	91,553	417,118	37,821	9.1%	379,297	90.9%

Figure 13-5 shows the volume trend of the Annual FTR Auctions from planning period 2009 to 2010 through December 31, 2013. The payout ratio, represented by the green bars, for 2013 to 2014 is not yet final. The cleared MW over these planning periods has been increasing for off-peak and on-peak prevailing flow FTRs, and has remained relatively steady for all other FTR classes.

Figure 13-5 Annual FTR Auction volume: Planning period 2009 to 2010 to 2013 to 2014

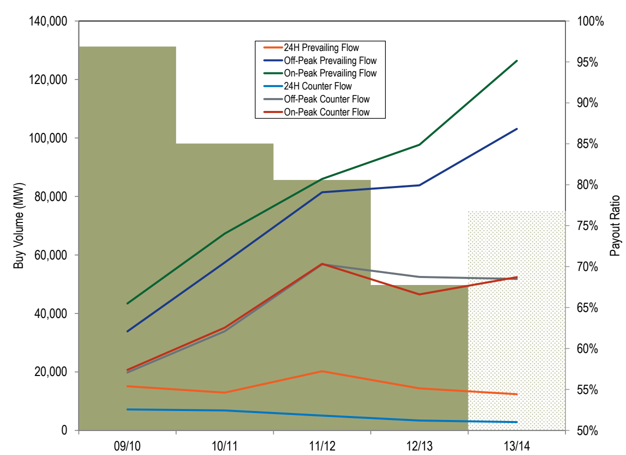


Table 13-10 shows the proportion of ARRs self scheduled as FTRs for the last five planning periods. The maximum possible level of self-scheduled FTRs includes all ARR, including RTEP ARRs. Eligible participants self-scheduled 29,341 MW (31.2 percent) of ARRs into FTRs for the 2013 to 2014 planning period, down from 41,716 MW (42.1 percent) in the previous planning period.

Table 13-10 Comparison of self-scheduled FTRs: Planning periods from 2009 to 2010 through 2013 to 2014

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,735	44.4%
2012/2013	41,716	99,115	42.1%
2013/2014	29,341	94,061	31.2%

In an effort to reduce FTR underfunding caused by forced Stage 1A infeasibilities, PJM may use reduced capability limits instead of the increased Stage 1A capability limits in FTR auctions. These capability limits may be reduced if ARR funding is not impacted, all requested self-scheduled FTRs clear and net FTR Auction revenue is positive. If the normal capability limit cannot be reached due to infeasibilities then FTR Auction capability reductions are undertaken pro-rata based on the MWs of Stage 1A infeasibility. Reducing capability limits will reduce the number of oversold FTR facilities due to forced Stage 1A infeasibilities and reduce underfunding caused by these ARR infeasibilities. The downside to this strategy is that there will be less FTRs for sale in the FTR Auctions, therefore, less auction revenue will be collected to pay ARR holders.

Also in an effort to reduce FTR underfunding, PJM implemented a new rule stating that PJM may model normal capability limits on facilities which are infeasible due to modeled transmission outages in Monthly Balance of Planning Period FTR Auctions. The capability of these facilities may be reduced if ARR target allocations are fully funded and net auction revenues are greater than zero. The results of this action should be an increased feasibility of the FTR model and a reduced risk of FTR underfunding, but will lead to a reduction in FTR Auction revenue due to a lower capability.

Table 13-11 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2012 to 2013 planning period and the first seven months of the 2013 to 2014 planning period. There were 13,634,312 MW of FTR buy bid obligations and 2,969,751 MW of FTR sell offer obligations for all bidding periods in the first seven months of the 2013 to 2014 planning period. The monthly balance of planning period auctions cleared 2,186,617 MW (16.0 percent) of FTR buy bid obligations and 431,536 MW (11.9 percent) of FTR sell offer obligations.

There were 2,882,925 MW of FTR buy bid options and 979,578 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2013 to 2014 planning period. The monthly auctions cleared 96,794 (3.3 percent) of FTR buy bid options, and 311,195 MW (31.8 percent) of FTR sell offers.

Table 13-11 Monthly Balance of Planning Period FTR Auction market volume: January through December 2013

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-13	Obligations	Buy bids	150,397	963,036	166,622	17.3%	796,414	82.7%
		Sell offers	84,563	297,609	34,710	11.7%	262,899	88.3%
	Options	Buy bids	2,830	104,318	6,767	6.5%	97,551	93.5%
		Sell offers	10,204	73,624	17,322	23.5%	56,302	76.5%
Feb-13	Obligations	Buy bids	164,620	1,035,756	166,386	16.1%	869,369	83.9%
		Sell offers	76,210	261,631	36,402	13.9%	225,229	86.1%
	Options	Buy bids	2,518	94,039	4,749	5.0%	89,290	95.0%
		Sell offers	9,053	62,833	16,434	26.2%	46,399	73.8%
Mar-13	Obligations	Buy bids	168,718	1,092,986	188,849	17.3%	904,138	82.7%
		Sell offers	77,248	256,820	40,079	15.6%	216,741	84.4%
	Options	Buy bids	2,674	103,046	5,591	5.4%	97,455	94.6%
		Sell offers	10,054	84,993	21,581	25.4%	63,411	74.6%
Apr-13	Obligations	Buy bids	130,671	742,450	143,747	19.4%	598,703	80.6%
		Sell offers	55,739	206,725	33,203	16.1%	173,522	83.9%
	Options	Buy bids	1,852	47,911	4,069	8.5%	43,842	91.5%
		Sell offers	6,017	58,130	17,259	29.7%	40,870	70.3%
May-13	Obligations	Buy bids	99,964	562,240	119,522	21.3%	442,718	78.7%
		Sell offers	25,028	93,603	19,917	21.3%	73,686	78.7%
	Options	Buy bids	792	33,223	2,901	8.7%	30,322	91.3%
		Sell offers	2,634	24,643	15,506	62.9%	9,137	37.1%
Jun-13	Obligations	Buy bids	268,004	1,548,839	275,485	17.8%	1,273,354	82.2%
		Sell offers	150,754	474,950	59,536	12.5%	415,415	87.5%
	Options	Buy bids	4,155	313,972	14,825	4.7%	299,147	95.3%
		Sell offers	23,090	198,850	55,455	27.9%	143,395	72.1%
Jul-13	Obligations	Buy bids	296,234	2,006,362	281,879	14.0%	1,724,483	86.0%
		Sell offers	142,594	429,555	57,422	13.4%	372,133	86.6%
	Options	Buy bids	10,303	564,738	16,412	2.9%	548,326	97.1%
		Sell offers	20,146	140,558	51,541	36.7%	89,018	63.3%
Aug-13	Obligations	Buy bids	337,418	2,283,124	334,179	14.6%	1,948,945	85.4%
		Sell offers	133,353	385,475	61,167	15.9%	324,309	84.1%
	Options	Buy bids	8,850	443,384	12,719	2.9%	430,665	97.1%
		Sell offers	21,320	147,295	45,916	31.2%	101,379	68.8%
Sep-13	Obligations	Buy bids	316,757	2,128,460	354,081	16.6%	1,774,379	83.4%
		Sell offers	186,831	421,145	65,522	15.6%	355,623	84.4%
	Options	Buy bids	8,735	476,204	19,173	4.0%	457,032	96.0%
		Sell offers	20,991	137,118	47,328	34.5%	89,790	65.5%
Oct-13	Obligations	Buy bids	278,253	1,828,738	309,173	16.9%	1,519,565	83.1%
		Sell offers	149,754	410,505	64,132	15.6%	346,373	84.4%
	Options	Buy bids	9,107	404,346	13,732	3.4%	390,614	96.6%
		Sell offers	17,560	129,935	36,112	27.8%	93,822	72.2%
Nov-13	Obligations	Buy bids	280,197	1,882,603	315,898	16.8%	1,566,704	83.2%
		Sell offers	138,601	379,154	58,685	15.5%	320,469	84.5%
	Options	Buy bids	8,701	424,561	12,156	2.9%	412,404	97.1%
		Sell offers	15,495	104,508	32,240	30.8%	72,268	69.2%
Dec-13	Obligations	Buy bids	244,187	1,956,187	315,922	16.1%	1,640,265	83.9%
		Sell offers	133,204	382,140	65,072	17.0%	317,067	83.0%
	Options	Buy bids	9,184	342,546	7,776	2.3%	334,770	97.7%
		Sell offers	16,317	121,314	42,605	35.1%	78,710	64.9%
2012/2013*	Obligations	Buy bids	2,255,105	12,956,832	2,171,751	16.8%	10,785,081	83.2%
		Sell offers	1,080,775	3,922,225	468,426	11.9%	3,453,798	88.1%
	Options	Buy bids	103,926	6,728,856	74,889	1.1%	6,653,967	98.9%
		Sell offers	149,274	1,088,211	268,684	24.7%	819,527	75.3%
2013/2014**	Obligations	Buy bids	2,021,050	13,634,312	2,186,617	16.0%	11,447,695	84.0%
		Sell offers	1,035,091	2,882,925	431,536	15.0%	2,451,389	85.0%
	Options	Buy bids	59,035	2,969,751	96,794	3.3%	2,872,957	96.7%
		Sell offers	134,919	979,578	311,195	31.8%	668,382	68.2%

* Shows Twelve Months for 2012/2013; ** Shows seven months ended 31-Dec-13 for 2013/2014

Table 13-12 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for January through December 2013 is 257,717.7 MW. The average monthly cleared volume for January through December 2012 was 176,910.2 MW.

Table 13-12 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through December 2013

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	Bid	595,260	191,417	115,207				165,471	1,067,354
	Cleared	125,075	24,018	8,251				16,045	173,389
Feb-13	Bid	654,446	174,360	177,548				123,440	1,129,794
	Cleared	131,562	15,659	13,975				9,939	171,135
Mar-13	Bid	645,247	232,876	224,105				93,804	1,196,032
	Cleared	136,007	27,219	24,669				6,544	194,440
Apr-13	Bid	610,571	179,789						790,360
	Cleared	127,896	19,920						147,816
May-13	Bid	595,463							595,463
	Cleared	122,423							122,423
Jun-13	Bid	766,947	218,427	205,723	112,180	195,196	193,766	170,571	1,862,810
	Cleared	141,332	31,035	25,346	14,149	27,397	25,560	25,491	290,310
Jul-13	Bid	921,277	343,637	244,602		329,350	349,639	382,594	2,571,100
	Cleared	158,643	30,086	15,959		27,840	34,134	31,628	298,291
Aug-13	Bid	1,076,550	268,252	266,570		331,723	393,247	390,165	2,726,508
	Cleared	178,551	26,336	22,399		30,116	47,483	42,012	346,898
Sep-13	Bid	934,389	330,547	344,156		250,625	375,174	369,773	2,604,664
	Cleared	188,437	37,569	36,258		23,153	45,357	42,480	373,253
Oct-13	Bid	881,879	334,532	292,728			347,421	376,525	2,233,085
	Cleared	169,523	39,747	20,054			45,843	47,738	322,905
Nov-13	Bid	978,927	327,581	306,138			309,506	385,011	2,307,163
	Cleared	190,228	28,048	23,552			36,379	49,848	328,055
Dec-13	Bid	930,516	383,830	378,094			225,178	381,114	2,298,733
	Cleared	168,414	42,300	38,165			26,989	47,830	323,698

Figure 13-6 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2013, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with an accompanying rise in the share of Annual FTRs.

Figure 13-6 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2013

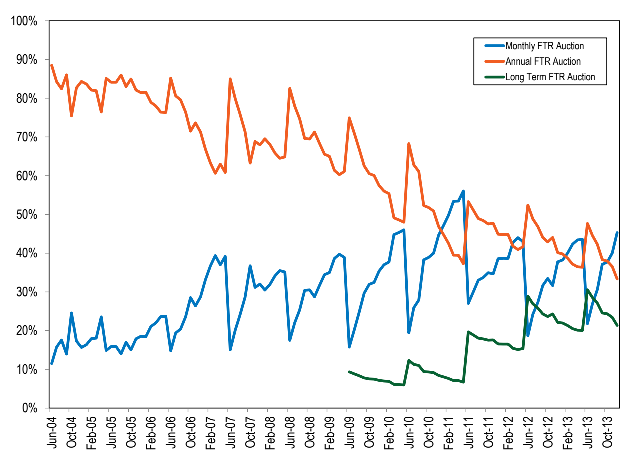


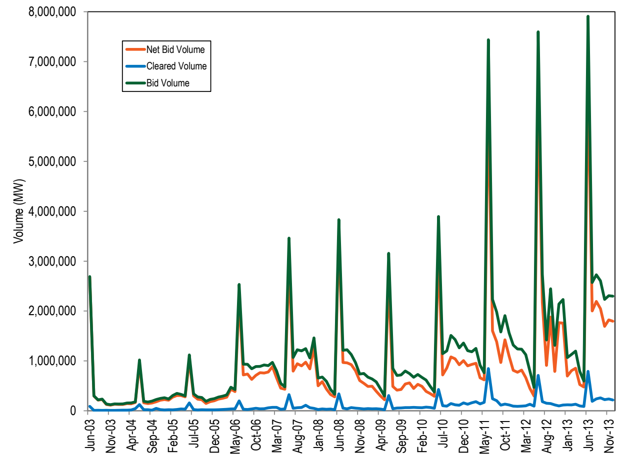
Table 13-13 provides the secondary bilateral FTR market volume for the entire 2012 to 2013 and 2013 to 2014 planning periods.

Table 13-13 Secondary bilateral FTR market volume: Planning periods 2012 to 2013 and 2013 to 2014[8]

Planning Period	Hedge Type	Class Type	Volume (MW)
2012/2013	Obligation	24-Hour	95
		On Peak	137
		Off Peak	60
		Total	292
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0
2013/2014	Obligation	24-Hour	110
		On Peak	41,590
		Off Peak	34,178
		Total	75,879
	Option	24-Hour	0
		On Peak	9,724
		Off Peak	914
		Total	10,638

Figure 13-7 shows the FTR bid, cleared and net bid volume from June 2003 through December 2013 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume is the volume of FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers, excluding sell offers. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

Figure 13-7 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2013



Price

Table 13-14 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2014 to 2017 Long Term FTR Auction. Only FTR obligation products are available in the Long Term FTR Auctions. In this auction, weighted-average buy bid FTR prices were $0.03 per MW, down $0.02 from 2013 to 2016 Long Term FTR Auction prices, while weighted-average sell offer FTR prices were $0.11 per MW, down $0.03 per MW from the previous Long Term FTR Auction.

8 The 2013 to 2014 planning period covers bilateral FTRs that are effective for any time between June 1, 2013 through December 31, 2013, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Table 13-14 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2014 to 2017

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($0.68)	($0.22)	($0.36)	($0.29)
		Year 2	($0.68)	($0.19)	($0.27)	($0.25)
		Year 3	($0.54)	($0.17)	($0.25)	($0.21)
		Year All	NA	($0.04)	($0.08)	($0.05)
		Total	($0.65)	($0.17)	($0.28)	($0.23)
	Prevailing Flow	Year 1	$0.23	$0.19	$0.31	$0.24
		Year 2	$0.17	$0.15	$0.27	$0.20
		Year 3	$0.19	$0.14	$0.23	$0.18
		Year All	NA	$0.04	$0.08	$0.05
		Total	$0.19	$0.16	$0.27	$0.21
	Total		($0.18)	$0.02	$0.06	$0.03
Sell offers	Counter Flow	Year 1	($2.89)	($0.29)	($0.50)	($0.39)
		Year 2	NA	($0.33)	($0.60)	($0.45)
		Year 3	NA	($0.34)	($0.65)	($0.49)
		Year All	NA	NA	NA	NA
		Total	($2.89)	($0.31)	($0.54)	($0.42)
	Prevailing Flow	Year 1	$0.26	$0.23	$0.40	$0.31
		Year 2	$0.08	$0.13	$0.35	$0.22
		Year 3	NA	$0.18	$0.38	$0.23
		Year All	NA	NA	NA	NA
		Total	$0.12	$0.19	$0.38	$0.27
	Total		$0.03	$0.07	$0.16	$0.11

Figure 13-8 shows the cleared buy bid price frequency for the 2014 to 2017 Long Term FTR Auction and that 97.6 percent of Long Term FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The majority of the cleared bids for the 2014 to 2017 Long Term FTR Auction fall into the $0 to $2 range.

Figure 13-8 Long Term FTR Auction clearing price per MW frequency: Planning periods 2014 to 2017

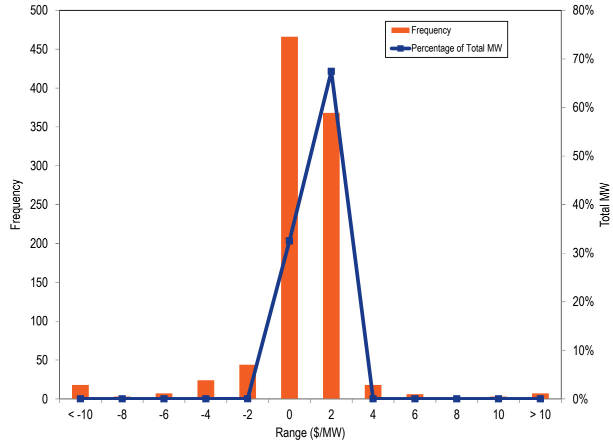


Table 13-15 shows the weighted-average cleared buy-bid prices by trade type, hedge type, FTR direction and class type for the Annual FTR Auction for the 2013 to 2014 planning period. The weighted-average buy-bid FTR price in the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period.

Table 13-15 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2013 to 2014

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.17)	($0.30)	($0.15)	($0.22)
		Prevailing Flow	$0.59	$0.51	$0.32	$0.43
		Total	$0.45	$0.27	$0.16	$0.23
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.19	$0.17	$0.10	$0.13
		Total	$1.19	$0.17	$0.10	$0.13
Self-scheduled bids	Obligations	Counter Flow	($0.24)	NA	NA	($0.24)
		Prevailing Flow	$0.73	NA	NA	$0.73
		Total	$0.72	NA	NA	$0.72
Buy and self-scheduled bids	Obligations	Counter Flow	($0.18)	($0.30)	($0.15)	($0.22)
		Prevailing Flow	$0.69	$0.51	$0.32	$0.49
		Total	$0.64	$0.27	$0.16	$0.30
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.19	$0.17	$0.10	$0.13
		Total	$1.19	$0.17	$0.10	$0.13
Sell offers	Obligations	Counter Flow	($1.95)	($0.57)	($0.35)	($0.54)
		Prevailing Flow	$0.35	$0.38	$0.21	$0.30
		Total	($0.18)	$0.14	$0.02	$0.05
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.07	$0.07	$0.07
		Total	$0.00	$0.07	$0.07	$0.07

Figure 13-9 shows the volume-weighted average buy bid price for the Annual FTR Auctions from the 2009 to 2010 planning period through December 31, 2013 of the 2013 to 2014 planning period. The payout ratio, represented by gray bars, for the 2013 to 2014 planning period is not yet final. Overall, the prices of 24 hour obligation FTRs are down, while Off-peak and On-peak FTR buy bid prices remain relatively unchanged.

Figure 13-9 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through December 31, 2013

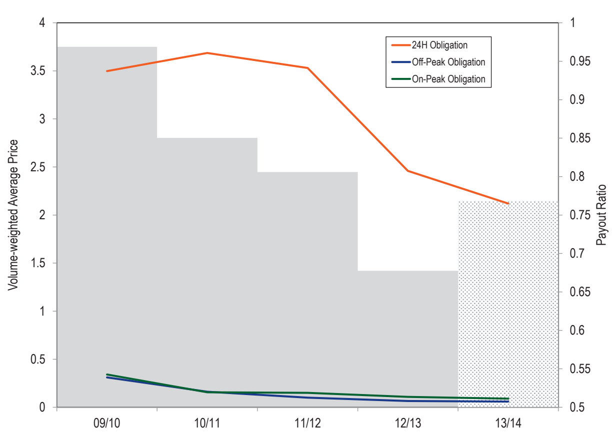


Figure 13-10 shows the weighted-average cleared buy-bid price frequency for the 2013 to 2014 Annual FTR Auction. 92.9 percent of Annual FTRs were purchased for less than $1 per MW.

Figure 13-10 Annual FTR Auction clearing price per MW: Planning period 2013 to 2014

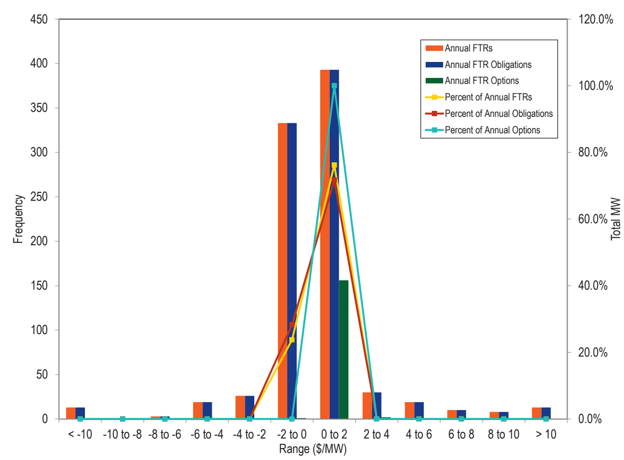


Table 13-16 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2013 through December 2013. For example, for the January 2013 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is

March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2013 Monthly Balance of Planning Period FTR Auction.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through December 2013 was $0.06 per MW, down from $0.12 per MW in the same time last year.

Table 13-16 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through December 2013

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	$0.11	$0.20	$0.05				$0.09	$0.11
Feb-13	$0.09	$0.12	$0.10				$0.13	$0.10
Mar-13	$0.10	$0.12	$0.10				$0.05	$0.10
Apr-13	$0.10	$0.16						$0.11
May-13	$0.09	$0.00						$0.09
Jun-13	$0.08	$0.21	$0.19	$0.15	$0.16	$0.14	$0.10	$0.06
Jul-13	$0.10	$0.17	($0.14)		$0.12	$0.07	$0.06	$0.08
Aug-13	$0.08	$0.17	$0.07		$0.07	$0.07	$0.06	$0.08
Sep-13	$0.06	$0.07	$0.04		$0.11	$0.09	$0.06	$0.07
Oct-13	$0.08	$0.09	($0.01)			$0.08	$0.07	$0.06
Nov-13	$0.06	$0.07	$0.12			$0.05	$0.07	$0.04
Dec-13	$0.07	$0.09	$0.04			$0.12	$0.08	$0.06

Profitability

Table 13-17 FTR profits by organization type and FTR direction: January through December 2013

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($43,931,263)	$167,898,667	$44,305,554	$1,907,612	$170,180,569
Financial	$50,622,405	NA	$126,872,101	NA	$177,494,506
Total	$6,691,142	$167,898,667	$171,177,655	$1,907,612	$347,675,076

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but the ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 13-17 lists FTR profits by organization type and FTR direction for the period from January through December, 2013. FTR profits are the sum of the daily FTR credits, including for self-scheduled FTRs, minus the daily FTR auction costs for each FTR held by an organization. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days, but self-scheduled FTRs have zero cost. FTRs were profitable overall, with $170.2 million in profits for physical entities, of which $169.8 million was from self-scheduled FTRs, and $177.5 million for financial entities.

Table 13-18 lists the monthly FTR profits in 2013 by organization type.

Table 13-18 Monthly FTR profits by organization type: January through December 2013

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$4,433,798	$24,630,019	$13,640,158	$42,703,975
Feb	$14,090,796	$20,676,306	$16,980,941	$51,748,044
Mar	($9,498,908)	$15,149,289	$4,849,731	$10,500,113
Apr	($12,666,550)	$6,571,358	$2,187,796	($3,907,396)
May	($3,242,261)	$14,590,963	$12,513,107	$23,861,810
Jun	$1,557,793	$12,289,397	$14,357,719	$28,204,910
Jul	$9,677,398	$20,442,580	$33,133,249	$63,253,226
Aug	(11,149,377.18)	$6,876,920	$3,987,989	($284,468)
Sep	$9,770,015	$14,681,142	$30,413,658	$54,864,815
Oct	($3,363,184)	$7,679,380	$8,438,729	$12,754,925
Nov	($3,783,325)	$10,090,289	$9,346,813	$15,653,777
Dec	$4,548,096	$16,128,634	$27,644,615	$48,321,345
Total	$374,291	$169,806,278	$177,494,506	$347,675,076

Revenue

Long Term FTR Auction Revenue

Table 13-19 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2014 to 2017 Long Term FTR Auction netted $16.8 million in revenue, $11.8 million less than the previous Long Term FTR Auction. Buyers paid $27.2 million and sellers received $10.4 million, down $35.5 million and $23.7 million over the previous Long Term FTR Auction.

Table 13-19 Long Term FTR Auction Revenue: Planning periods 2014 to 2017

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($2,686,267)	($17,437,460)	($15,165,264)	($35,288,992)
		Year 2	($2,517,547)	($12,137,365)	($10,466,042)	($25,120,954)
		Year 3	($1,034,386)	($11,337,075)	($9,840,633)	($22,212,094)
		Year All	$0	($952,834)	($1,125,735)	($2,078,569)
		Total	($6,238,200)	($41,864,735)	($36,597,675)	($84,700,609)
	Prevailing Flow	Year 1	$475,987	$26,701,546	$19,917,305	$47,094,838
		Year 2	$779,165	$19,766,021	$13,859,144	$34,404,330
		Year 3	$1,112,584	$16,609,539	$11,914,315	$29,636,438
		Year All	$0	$364,497	$402,309	$766,806
		Total	$2,367,736	$63,441,603	$46,093,074	$111,902,412
	Total		($3,870,464)	$21,576,868	$9,495,400	$27,201,803
Sell offers	Counter Flow	Year 1	($126,480)	($2,763,327)	($2,103,648)	($4,993,454)
		Year 2	$0	($2,123,903)	($1,500,852)	($3,624,754)
		Year 3	0	($397,087)	($215,352)	($612,439)
		Year All	NA	NA	NA	NA
		Total	($126,480)	($5,284,316)	($3,819,851)	($9,230,647)
	Prevailing Flow	Year 1	$88,606	$7,106,180	$5,129,677	$12,324,463
		Year 2	$34,781	$4,520,648	$2,127,053	$6,682,482
		Year 3	48,560	$392,453	$212,369	$653,382
		Year All	NA	NA	NA	NA
		Total	$171,947	$12,019,281	$7,469,099	$19,660,327
	Total		$45,468	$6,734,965	$3,649,247	$10,429,680
Total			($3,915,932)	$14,841,903	$5,846,152	$16,772,123

For the 2014 to 2017 Long Term FTR Auction, the counter flow FTRs netted -$75.5 million in revenue, down $63.0 million, while prevailing flow FTRs netted $ 92.2 million in revenue, down $104.1 million from the previous Long Term FTR Auction.

Figure 13-11 summarizes total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2014 to 2017 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $46.0 million of the total revenue of $29.8 million paid in the auction, they also comprised 7.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$22.6 million of revenue and constituted 2.9 percent of all FTRs bought in the auction.

Figure 13-11 Ten largest positive and negative revenue production FTR sources purchased in the Long Term FTR Auction: Planning periods 2014 to 2017

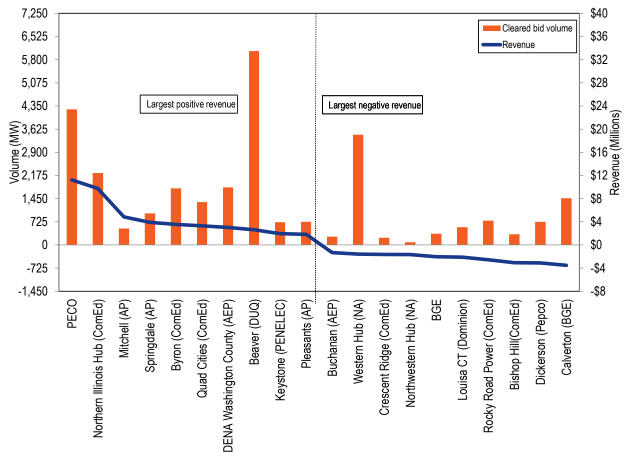


Figure 13-12 Ten largest positive and negative revenue producing sinks purchased in the Long Term FTR Auction: Planning periods 2014 to 2017[10]

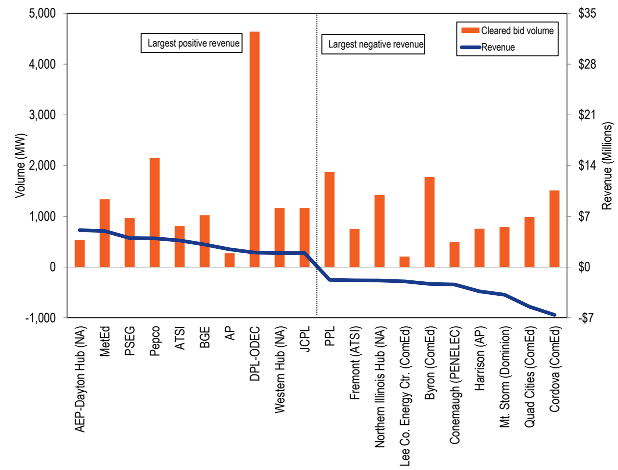


Figure 13-12 summarizes the total revenue associated with all FTRs, regardless of source, to FTR sources that produced the largest positive and negative revenue from the 2014 to 2017 Long Term FTR Auction.[9] The top 10 positive revenue production FTR sinks accounted for $33.1 million of the total revenue of $40.4 million paid in the auction, they also comprised 5.0 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$31.4 million of revenue and constituted 3.8 percent of all FTRs bought in the auction.

Annual FTR Auction Revenue

Table 13-20 shows the Annual FTR Auction revenue by trade type, hedge type, FTR direction and class type. The Annual FTR Auction for the 2013 to 2014 planning period generated $558.4 million, down 7.4 percent from $602.9 million in the 2012 to 2013 planning period, and down 45.8 percent from the 2011 to 2012 planning period. Counter flow FTR holders received $73.5 million from the auction and prevailing flow FTR holders paid $631.9 million.

9 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce the net auction revenue, therefore, the sum of the highest revenue production FTRs can exceed the net auction revenue.

10 For Figure 13-11 through Figure 13-16, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Table 13-20 Annual FTR Auction revenue: Planning period 2013 to 2014

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($3,584,655)	($61,297,999)	($34,970,300)	($99,852,954)
		Prevailing Flow	$57,603,843	$244,753,274	$143,657,697	$446,014,815
		Total	$54,019,189	$183,455,275	$108,687,397	$346,161,861
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$773,687	$20,414,078	$15,109,880	$36,297,645
		Total	$773,687	$20,414,078	$15,109,880	$36,297,645
	Total	Counter Flow	($3,584,655)	($61,297,999)	($34,970,300)	($99,852,954)
		Prevailing Flow	$58,377,530	$265,167,352	$158,767,577	$482,312,460
		Total	$54,792,875	$203,869,353	$123,797,277	$382,459,506
Self-scheduled bids	Obligations	Counter Flow	($484,421)	NA	NA	($484,421)
		Prevailing Flow	$185,666,567	NA	NA	$185,666,567
		Total	$185,182,146	NA	NA	$185,182,146
Buy and self-scheduled bids	Obligations	Counter Flow	($4,069,076)	($61,297,999)	($34,970,300)	($100,337,375)
		Prevailing Flow	$243,270,411	$244,753,274	$143,657,697	$631,681,382
		Total	$239,201,335	$183,455,275	$108,687,397	$531,344,007
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$773,687	$20,414,078	$15,109,880	$36,297,645
		Total	$773,687	$20,414,078	$15,109,880	$36,297,645
	Total	Counter Flow	($4,069,076)	($61,297,999)	($34,970,300)	($100,337,375)
		Prevailing Flow	$244,044,097	$265,167,352	$158,767,577	$667,979,027
		Total	$239,975,022	$203,869,353	$123,797,277	$567,641,652
Sell offers	Obligations	Counter Flow	($6,178,881)	($10,761,004)	($9,879,378)	($26,819,263)
		Prevailing Flow	$3,672,742	$21,045,102	$11,155,364	$35,873,207
		Total	($2,506,139)	$10,284,097	$1,275,986	$9,053,944
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$87,616	$133,050	$220,666
		Total	$0	$87,616	$133,050	$220,666
	Total	Counter Flow	($6,178,881)	($10,761,004)	($9,879,378)	($26,819,263)
		Prevailing Flow	$3,672,742	$21,132,718	$11,288,414	$36,093,874
		Total	($2,506,139)	$10,371,714	$1,409,036	$9,274,610
Total			$242,481,161	$193,497,639	$122,388,241	$558,367,042

Figure 13-13 summarizes the total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Annual FTR Auction for the 2013 to 2014 planning period. The top ten positive revenue sinks accounted for 65.0 percent of total revenue. The top ten negative revenue sinks accounted for 3.9 percent of total revenue.

Figure 13-13 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2013 to 2014

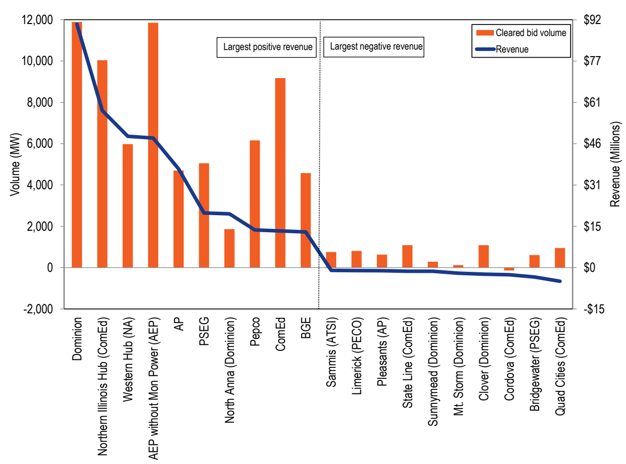
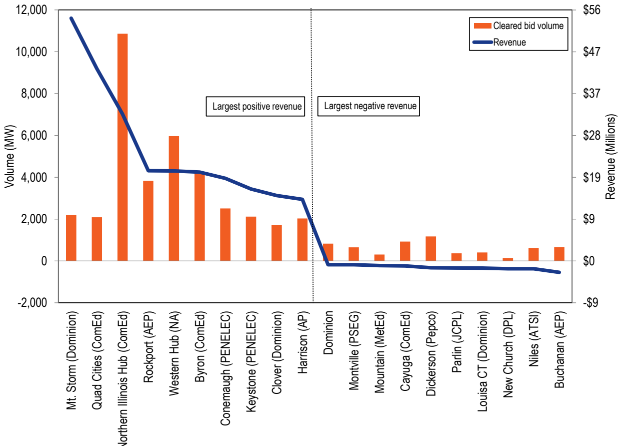


Figure 13-14 summarizes the total revenue associated with all FTRs, regardless of sink, to the FTR sinks that produced the largest positive and negative revenue in the Annual FTR Auction for the 2013 to 2014 planning period. The top 10 positive revenue sinks accounted for 45.2 percent of total revenue. The top 10 negative revenue sinks accounted for 2.6 percent of total revenue.

Figure 13-14 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2013 to 2014



Monthly Balance of Planning Period FTR Auction Revenue

Table 13-21 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through December 2013. The Monthly Balance of Planning Period FTR Auction netted $5.4 million in revenue, with buyers paying $116.0 million and sellers receiving $110.6 million for the first seven months of the 2013 to 2014 planning period. Net revenues were down 68.8 percent, with a net revenue of $17.3 million for the first seven months of the 2012 to 2013 planning period. For the entire 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions netted $23.8 million in revenue with buyers paying $127.7 million and sellers receiving $22.1 million. For the entire 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions netted $26.3 million in revenue with buyers paying $132.6 million and sellers receiving $106.4 million.

Table 13-21 Monthly Balance of Planning Period FTR Auction revenue: January through December 2013

Monthly Auction	Type	Trade Type	Class Type 24-Hour	On Peak	Off Peak	All
Jan-13	Obligations	Buy bids	$42,552	$4,558,023	$3,371,362	$7,971,937
		Sell offers	$106,975	$2,609,123	$1,599,772	$4,315,870
	Options	Buy bids	$0	$237,321	$153,334	$390,655
		Sell offers	$0	$1,133,641	$1,206,317	$2,339,958
Feb-13	Obligations	Buy bids	$176,565	$3,587,647	$2,468,155	$6,232,366
		Sell offers	$401,600	$1,782,016	$1,097,066	$3,280,682
	Options	Buy bids	$5,100	$99,651	$128,731	$233,482
		Sell offers	$0	$861,109	$904,603	$1,765,712
Mar-13	Obligations	Buy bids	$189,939	$4,040,854	$3,035,268	$7,266,060
		Sell offers	$61,862	$2,221,264	$1,434,875	$3,718,001
	Options	Buy bids	$16,526	$229,272	$95,137	$340,935
		Sell offers	$0	$1,242,062	$1,381,010	$2,623,072
Apr-13	Obligations	Buy bids	($27,848)	$3,384,641	$2,231,023	$5,587,816
		Sell offers	$414,627	$1,703,707	$1,085,350	$3,203,684
	Options	Buy bids	$46,767	$236,939	$92,241	$375,947
		Sell offers	$0	$816,642	$702,628	$1,519,270
May-13	Obligations	Buy bids	$22,637	$2,501,391	$1,418,753	$3,942,781
		Sell offers	$210,649	$1,133,878	$524,793	$1,869,320
	Options	Buy bids	$0	$146,702	$55,903	$202,605
		Sell offers	$441	$739,219	$602,794	$1,342,454
Jun-13	Obligations	Buy bids	$258,896	$12,840,102	$8,210,854	$21,309,852
		Sell offers	$6,203,476	$4,763,316	$2,821,569	$13,788,360
	Options	Buy bids	$1,937	$527,792	$270,176	$799,905
		Sell offers	$0	$4,338,954	$2,862,300	$7,201,254
Jul-13	Obligations	Buy bids	$510,314	$9,102,951	$4,353,703	$13,966,968
		Sell offers	$93,068	$5,789,068	$4,745,346	$10,627,482
	Options	Buy bids	$4,131	$627,541	$557,307	$1,188,979
		Sell offers	$0	$3,737,741	$3,401,595	$7,139,335
Aug-13	Obligations	Buy bids	$865,368	$8,730,071	$6,036,457	$15,631,896
		Sell offers	$80,061	$5,495,491	$4,455,681	$10,031,232
	Options	Buy bids	$2,361	$533,585	$446,817	$982,762
		Sell offers	$0	$2,977,768	$2,590,004	$5,567,772
Sep-13	Obligations	Buy bids	$528,800	$8,147,903	$5,670,300	$14,347,003
		Sell offers	$219,616	$4,804,814	$3,795,424	$8,819,854
	Options	Buy bids	$633	$617,446	$628,494	$1,246,573
		Sell offers	$0	$3,184,129	$2,500,854	$5,684,983
Oct-13	Obligations	Buy bids	$1,686,257	$6,662,996	$5,029,439	$13,378,692
		Sell offers	$106,651	$4,788,674	$4,196,692	$9,092,018
	Options	Buy bids	$1,985	$450,964	$396,471	$849,419
		Sell offers	$0	$2,494,525	$1,831,822	$4,326,347
Nov-13	Obligations	Buy bids	$840,852	$6,572,261	$3,136,906	$10,550,020
		Sell offers	$157,148	$4,355,453	$2,684,978	$7,197,579
	Options	Buy bids	$0	$473,050	$413,497	$886,548
		Sell offers	$0	$1,988,825	$1,523,642	$3,512,467
Dec-13	Obligations	Buy bids	$615,410	$7,685,428	$4,886,446	$13,187,284
		Sell offers	$545,647	$3,994,464	$1,678,204	$6,218,314
	Options	Buy bids	$0	$572,909	$400,160	$973,069
		Sell offers	$0	$3,031,134	$2,631,315	$5,662,449
2012/2013*	Obligations	Buy bids	$67,116	$76,349,386	$43,832,157	$120,248,659
		Sell offers	$4,731,328	$40,127,400	$18,982,130	$63,840,858
	Options	Buy bids	$152,160	$4,512,768	$2,793,076	$7,458,004
		Sell offers	$313,760	$22,240,204	$17,444,010	$39,997,974
	Total		($4,825,812)	$18,494,550	$10,199,092	$23,867,830
2013/2014**	Obligations	Buy bids	$5,305,898	$59,741,712	$37,324,105	$102,371,715
		Sell offers	$7,405,666	$33,991,280	$24,377,894	$65,774,840
	Options	Buy bids	$161,270	$7,788,263	$5,635,822	$13,585,355
		Sell offers	$0	$24,937,206	$19,842,384	$44,779,590
	Total		($1,938,499)	$8,601,489	($1,260,352)	$5,402,639

* Shows Twelve Months; ** Shows seven months ended 31-Dec-2013 for 2013/2014

Figure 13-15 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period. The top 10 positive revenue producing FTR sources accounted for $42.5 million of the total revenue of $4.5 million paid in the auction, they also comprised 4.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$14.5 million of revenue and constituted 1.8 percent of all FTRs bought in the auction.

Figure 13-15 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through December 31, 2013

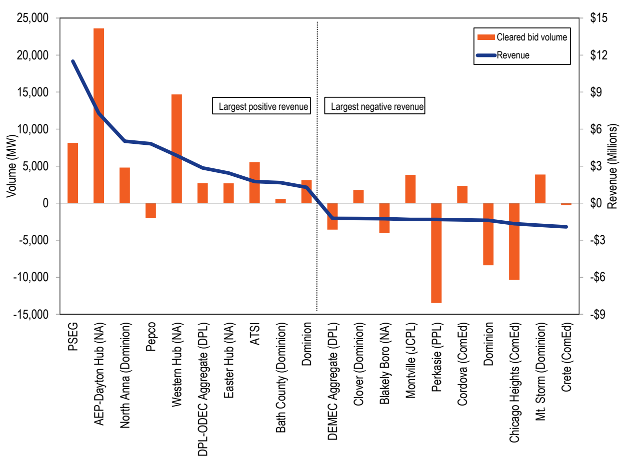
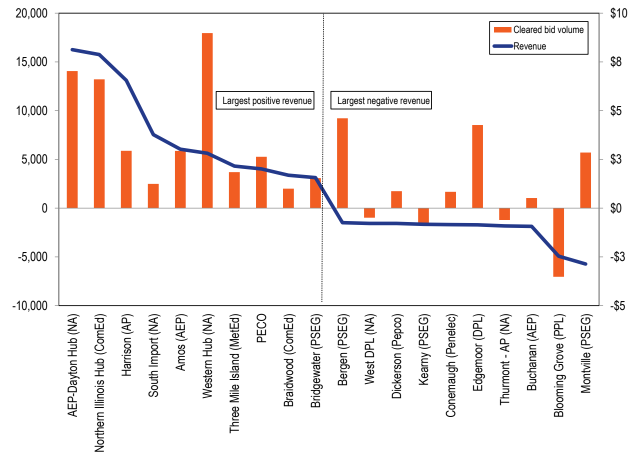


Figure 13-16 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period through December 31, 2013. The top 10 positive revenue producing FTR sources accounted for $39.6 million of the total revenue of $4.5 million paid in the auction, they also comprised 4.8 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$12.0 million of revenue and constituted 1.1 percent of all FTRs bought in the auction.

Figure 13-16 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through December 31, 2013



FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the first seven months of the 2013 to 2014 planning. Figure 13-17 shows the ten largest positive and negative FTR target allocations, summed by sink, for the first seven months of the 2013 to 2014 planning period. The top 10 sinks that produced financial benefit accounted for 19.1 percent of total positive target allocations during the 2013 to 2014 planning period with the Western Hub accounting for 3.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 7.6 percent of total negative target allocations with the AEP-Dayton Hub accounting for 1.1 percent of all negative target allocations.

Figure 13-17 Ten largest positive and negative FTR target allocations summed by sink: 2013 to 2014 planning period through December 31, 2013

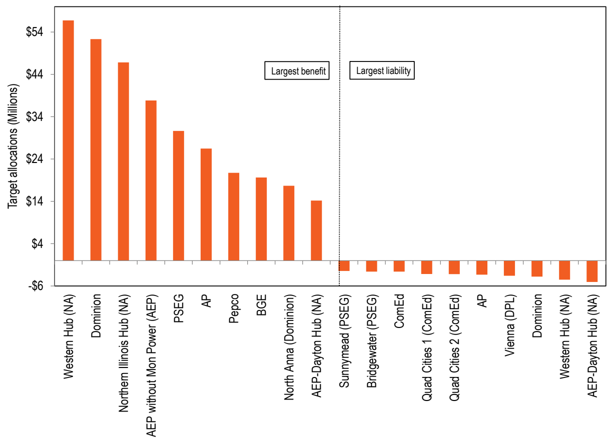
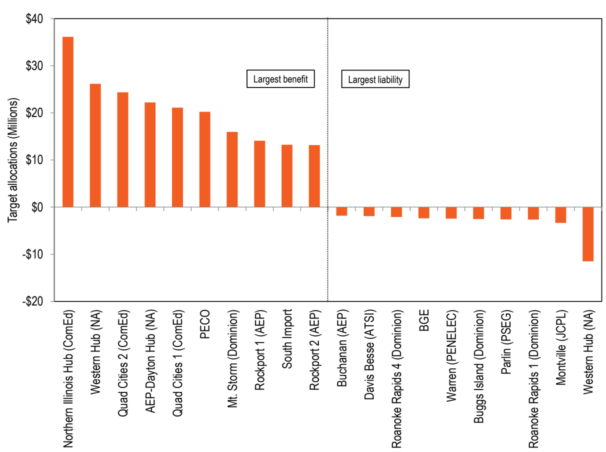


Figure 13-18 shows the ten largest positive and negative FTR target allocations, summed by source, for the first seven months of the 2013 to 2014 planning period. The top 10 sources with a positive target allocation accounted for 12.2 percent of total positive target allocations with the Northern Illinois Hub accounting for 2.1 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 7.4 percent of all negative target allocations, with the Western Hub accounting for 2.5 percent.

Figure 13-18 Ten largest positive and negative FTR target allocations summed by source: 2013 to 2014 planning period through December 31, 2013



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in 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 constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[11] That is the source of the congestion revenue to pay holders of ARRs and FTRs. In general, FTR revenue adequacy exists when the sum of congestion credits is equal to or greater than the sum of congestion across the positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues to the total target allocations across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. The adequacy of FTRs as an offset against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability or purchase of FTRs.

FTRs are paid each month from congestion revenues, both day-ahead and balancing, FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not

11 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets, and net negative congestion.[12] FTR revenues also include ARR excess, which is the difference between ARR target allocations and FTR auction revenues, and negative FTR target allocations, which is an income for the FTR market from FTRs with a negative target allocation. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-22 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates (M2M flowgates) in MISO and NYISO whose operating limits are respected by PJM.[13]

In 2013, the market to market operations resulted in NYISO, MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

For the 2012 to 2013 planning period, PJM paid MISO and NYISO a combined $40.3 million for the redispatch on the designated M2M flowgates, and for the first seven months of the 2013 to 2014 planning period PJM has paid MISO and NYISO a combined $2.3 million. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any previous PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

FTRs were paid at 75.1 percent of the target allocation level for the first seven months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the first seven months of the 2013 to 2014 planning period, and $335.7 million during the first seven months of the 2012 to 2013 planning period, a 14.4 percent decrease. For the first seven months of the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were the AEP-Dayton Hub and the Western Hub.

Table 13-22 presents the PJM FTR revenue detail for the 2012 to 2013 planning period and the first seven months of the 2013 to 2014 planning period.

12 Hourly congestion revenues may be negative.

13 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

Table 13-22 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

Accounting Element	2012/2013	2013/2014*
ARR information		
ARR target allocations	$587.0	$303.1
FTR auction revenue	$653.6	$341.3
ARR excess	$66.7	$36.0
FTR targets		
Positive target allocations	$992.9	$663.5
Negative target allocations	($86.1)	($44.3)
FTR target allocations	$906.8	$619.2
Adjustments:		
Adjustments to FTR target allocations	($1.0)	($0.5)
Total FTR targets	$905.8	$618.7
FTR revenues		
ARR excess	$66.7	$36.0
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($90.6)	($36.0)
Hourly congestion revenue	$668.4	$461.8
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($41.1)	($6.6)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.0)	$0.0
Total FTR revenues	$601.9	$455.2
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$12.1	$9.2
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$614.0	$287.4
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$614.0	$287.4
Remaining deficiency	$292.3	$154.2

* Shows seven months ended 31-Dec-13

Unallocated Congestion Charges

When congestion revenue at the end of an hour is negative, target allocations in that hour are set to zero, and there is a congestion liability for that hour. At the end of the month, if excess ARR revenue and excess congestion from other hours and months are not adequate to offset the sum of these hourly differences, day-ahead operating reserves are charged the unallocated congestion charges so that the total congestion for the month is not less than zero. This charge is applied retroactively at the end of the month as additional day-ahead operating reserves charges and is never credited back to day-ahead operating reserves in the case of excess congestion. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation and there was not enough excess during the month to pay the difference. From 2010 through May 31, 2012, these charges were only made three times, for a total of $7.3 million. However, in the 2012 to 2013 planning period these charges were made in five months for a total of $12.1 million in just one planning period.

Table 13-23 shows the monthly unallocated congestion charges made to day-ahead operating reserves for the 2012 to 2013 planning period and the 2013 to 2014 planning period through December. Months with no unallocated congestion are excluded from the table.[14]

Table 13-23 Unallocated congestion charges: Planning period 2012 to 2013 to 2013 and 2014

Period	Charge
Oct-12	$794,752
Dec-12	$193,429
Jan-13	$5,233,445
Mar-13	$701,303
May-13	$5,210,739
Jun-13	$2,828,660
Sep-13	$6,411,602
2012/2013	$12,133,668
2013/2014	$9,240,262

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and are defined to be the revenue required to compensate FTR holders for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-24 lists the FTR revenues, target allocations, credits, payout ratios, 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.

The total row in Table 13-24 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

14 See Section 4, "Energy Uplift" at "Energy Uplift Charges" for the impact of Unallocated Congestion Charges on Operating Reserve rates.

Table 13-24 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2012 to 2013 and 2013 to 2014

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-12	$58.5	$62.9	92.9%	$58.5	93.0%	($4.4)
Jul-12	$71.3	$80.0	88.9%	$71.3	88.9%	($8.8)
Aug-12	$54.1	$55.4	97.1%	$54.1	97.3%	($1.3)
Sep-12	$38.7	$82.5	46.7%	$38.7	46.8%	($43.8)
Oct-12	$24.3	$58.2	41.8%	$25.1	42.7%	($33.1)
Nov-12	$52.0	$59.6	87.2%	$52.0	87.3%	($7.5)
Dec-12	$36.3	$50.1	72.2%	$36.5	72.5%	($13.6)
Jan-13	$63.4	$120.3	53.4%	$68.6	56.5%	($51.7)
Feb-13	$77.2	$128.1	60.5%	$77.2	60.2%	($50.9)
Mar-13	$51.7	$70.7	73.2%	$52.4	74.2%	($18.2)
Apr-13	$32.7	$47.4	69.4%	$32.7	69.0%	($14.7)
May-13	$41.8	$90.7	46.1%	$47.0	51.9%	($43.7)
Summary for Planning Period 2012 to 2013						
Total	$601.9	$905.8		$614.0	67.8%	($291.8)
Jun-13	$61.3	$81.9	74.7%	$64.1	78.2%	($17.8)
Jul-13	$113.5	$128.3	88.3%	$113.5	88.5%	($14.7)
Aug-13	$43.1	$45.8	94.0%	$43.1	94.0%	($2.7)
Sep-13	$60.3	$116.0	52.0%	$66.7	57.5%	($49.3)
Oct-13	$47.4	$63.9	74.0%	$47.4	74.1%	($16.6)
Nov-13	$44.7	$66.9	66.9%	$44.7	66.9%	($22.1)
Dec-13	$85.0	$115.9	73.3%	$85.0	73.3%	($31.0)
Summary for Planning Period 2013 to 2014						
Total	$455.2	$618.7		$464.5	75.1%	($154.3)

Figure 13-19 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 2013. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 13-19 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratios for months in the 2013 to 2014 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 13-19 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2013

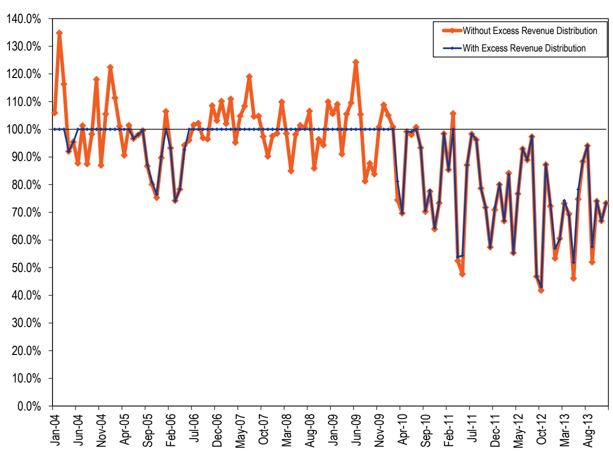


Table 13-25 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves.

Table 13-25 PJM reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	75.1%

*2013/2014 Through 31-Dec-13

FTR Uplift Charge

At the end of the planning period, an uplift charge is applied to FTR holders. This charge is to cover the net of the monthly deficiencies in the target allocations calculated for individual participants. An individual participant's uplift charge is a pro-rata charge, to cover this deficiency, based on their net target allocation with respect to the total net target allocation of all participants with net positive target allocations for the planning period. Participants pay an uplift charge that is a ratio of their share of net positive target allocations to the total net positive target allocations.

The uplift charge is only applied to, and calculated from, members with a net positive target allocation at the end of the planning period. Members with a net negative target allocation have their year-end target allocation set to zero for all uplift calculations. Since participants in the FTR market with net positive target allocations are paying the uplift charge to fully fund FTRs, their payout ratio cannot be 100 percent. The end of planning period payout ratio is calculated as the participant's target allocations minus the uplift charge applied to them divided by their target allocations. The calculations of uplift are structured so that, at the end of the planning period, every participant in the FTR market with a positive net target allocation receives payments based on the same payout ratio. At the end of the planning period and the end of a given month no payout ratio is actually applied to a participant's target allocations. The payout ratio is simply used as a reporting mechanism to demonstrate the amount of revenue available to pay target allocations and represent the percentage of target allocations a participant with a net positive portfolio has been paid for the planning period. However, this same calculation is not accurate when calculating a single month's payout ratio as currently reported, where the calculation of available revenue is not the same.

The total planning period target allocation deficiency is the sum of the monthly deficiencies throughout the planning period. The monthly deficiency is the difference in the net target allocation of all participants and the total revenue collected for that month. The total revenue paid to FTR holders is based on the hourly congestion revenue collected, which includes hourly M2M, wheel payments and unallocated congestion credits.

Table 13-26 provides a demonstration of how the FTR uplift charge is calculated. In this example it is important to note that the sum of the net positive target allocations is $32 and the total monthly deficiency is $10. The uplift charge is structured so that those with higher target allocations pay more of the deficit, which ultimately impacts their net payout. Also, in this example, and in the PJM settlement process, the monthly payout ratio varies for all participants, but the uplift charge is structured so that once the uplift charge is applied the end of planning period payout ratio is the same for all participants.

For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every participant experiences the same payout ratio. This means that some participants subsidize others and receive less payout from their FTRs after the uplift is applied, while others receive a subsidy and get a higher payout after the uplift is applied. In this example, participants 1 and 5 are paid less after the uplift charge is applied, while participants 3 and 4 are paid more.

Table 13-26 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	80.0%	68.8%
2	($4.00)	$0.00	$0.00	$0.00	($4.00)	100.0%	100.0%
3	$15.00	$10.00	$5.00	$4.69	$10.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00		

Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown in Table 13-27 reflect the PJM reported payout ratios for each month of the planning period. These reported payout ratios equal congestion revenue divided by the sum of the net positive and net negative target allocations for each hour of the month. This does not correctly measure the payout ratio actually received by positive target allocation FTR holders in the month, but provides an estimate of the ratio based on the approach to end of planning period calculations, including cross subsidies.

The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in a month. In fact, the actual monthly payout ratio includes the net negative target allocations as a source of funding for FTRs with net positive target allocations in an hour. Revenue from FTRs with net negative target allocations in an hour is included with congestion revenue when funding FTRs with net positive target allocations.[15] Also included in this revenue is any M2M charge or credit for the month and any excess ARR revenues for the month. The revenue and net target allocations are then summed over the month to calculate the monthly payout ratio. There is no payout ratio applied on a monthly basis, each participant receives a different share of the available revenue based on availability, it is simply used as a reporting mechanism. At the end of a given month, a participant's FTR payments are a proportion of the congestion credits collected, based on the participant's share of the total monthly target allocation. The payout ratio is only used and calculated at the end of the planning period after uplift is applied to each participant. The actual monthly payout ratio received by FTR holders equals congestion revenue plus the net negative target allocations divided by the net positive target allocations for each hour. The actual payout ratio received by the holders of positive target allocation FTRs, reported on a monthly basis, is greater than reported by PJM.

Table 13-27 shows the PJM reported and actual monthly payout ratio for the 2013 to 2014 planning period. In September 2013, the PJM reported payout ratio is 3.4 percentage points below the actual payout ratio. On a month to month basis, the payout ratio currently reported by PJM does not take into account all sources of revenue available to pay FTR holders. On a monthly basis, this provides a slightly overstated level of underfunding.

Table 13-27 PJM Reported and Actual Monthly Payout Ratios: Planning period 2013 to 2014

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jan-13	57.0%	59.9%
Feb-13	60.3%	62.5%
Mar-13	74.2%	75.5%
Apr-13	68.9%	70.8%
May-13	51.9%	54.2%
Jun-13	78.3%	79.5%
Jul-13	88.8%	89.3%
Aug-13	94.1%	94.7%
Sep-13	57.5%	61.0%
Oct-13	74.1%	76.2%
Nov-13	66.9%	69.1%
Dec-13	73.3%	74.8%

Netting Target Allocations within Portfolios

Currently, FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method

15 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), p. 50.

treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

In fact, if done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current system all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Elimination of portfolio netting should also be applied to the end of planning period FTR uplift calculation. With this approach, negative target allocations would not offset positive target allocations at the end of the planning period when allocating uplift. The FTR uplift charge would be based on participants' share of the total positive target allocations paid for the planning period.

Table 13-28 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net target allocation is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 13-28 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive Target Allocation	Negative Target Allocation	Percent Negative Target Allocation	Net Target Allocation	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	-	$115.00	$45.00	$45.00	-

Table 13-29 shows the total value for the 2012 to 2013 and first month of the 2013 to 2014 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

Table 13-29 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2012 to 2013 and 2013 to 2014

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jan-13	$129,096,732	($8,682,957)	$233,783,161	($113,347,680)	$68,617,681	57.0%	77.8%
Feb-13	$135,702,271	($7,613,234)	$259,657,461	($131,557,526)	$77,154,565	60.3%	80.4%
Mar-13	$74,421,312	($3,760,700)	$146,552,085	($75,878,638)	$52,428,118	74.2%	87.6%
Apr-13	$50,520,958	($3,090,289)	$108,760,047	($61,325,460)	$32,698,909	68.9%	86.5%
May-13	$95,352,565	($4,678,790)	$190,798,195	($100,110,478)	$47,015,169	51.9%	77.1%
Jun-13	$86,723,727	($4,836,912)	$164,066,220	($82,101,063)	$64,060,468	78.3%	89.1%
Jul-13	$134,302,957	($6,017,378)	$255,724,128	($127,113,708)	$113,548,567	88.8%	94.1%
Aug-13	$51,545,380	($5,741,003)	$104,601,365	($58,796,985)	$43,059,687	94.1%	97.4%
Sep-13	$126,168,822	($10,172,695)	$279,972,757	($163,977,565)	$66,719,631	57.5%	82.4%
Oct-13	$69,748,034	($5,779,197)	$158,354,017	($94,365,761)	$47,353,545	74.1%	89.5%
Nov-13	$71,460,441	($4,566,566)	$156,649,135	($89,755,253)	$44,748,426	66.9%	85.9%
Dec-13	$123,125,598	($7,182,127)	$256,139,289	($140,195,812)	$84,974,997	73.3%	87.9%
2012/2013 Total	$992,878,752	($86,061,137)	$1,897,830,880	($990,471,801)	$614,014,377	67.7%	84.5%
2013/2014 Total	$663,074,957	($44,295,877)	$1,375,506,911	($674,205,083)	$464,465,322	75.1%	82.8%

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.7 percent and the payout ratio for the seven months of the 2013 to 2014 planning period would have been 82.8 percent instead of 75.1 percent.

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. This increased payout ratio would apply only to negative target allocations associated with counter flow FTRs.

Table 13-30 Example implementation of counter flow adjustment method

	Prevailing A-B 10MW	Counter C-D 10MW
Auction Cost	$50.00	($30.00)
Target Allocation	$40.00	($20.00)
Payout	$30.00	($20.00)
Profit without underfunding	($10.00)	$10.00
Profit after underfunding	($20.00)	$10.00
Payout for Positive TA	$35.00	($20.00)
Profit for Positive TA	($15.00)	$10.00
Payout after CF Adjustment	$36.67	($21.67)
Profit after CF Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

Table 13-31 Counter flow FTR payout ratio adjustment impacts

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jan-13	$233,783,161	($113,347,680)	$120,435,482	$68,617,681	57.0%	$181,965,360	83.4%	$194,865,402
Feb-13	$259,657,461	($131,557,526)	$128,099,935	$77,154,565	60.2%	$208,712,090	85.4%	$221,784,584
Mar-13	$146,552,085	($75,878,638)	$70,673,447	$52,428,118	74.2%	$128,306,756	90.8%	$133,040,564
Apr-13	$108,760,047	($61,325,460)	$47,434,587	$32,698,909	68.9%	$94,024,369	90.2%	$98,077,747
May-13	$190,798,195	($100,110,478)	$90,687,717	$47,015,169	51.8%	$147,125,648	82.9%	$158,212,887
Jun-13	$164,066,220	($82,101,063)	$81,965,157	$64,060,468	78.2%	$146,161,531	91.9%	$150,770,760
Jul-13	$255,724,128	($127,113,708)	$128,610,420	$113,548,567	88.3%	$240,662,275	95.6%	$244,362,737
Aug-13	$104,601,365	($58,796,985)	$45,804,380	$43,059,687	94.0%	$101,856,672	98.1%	$102,592,928
Sep-13	$279,972,757	($163,977,565)	$115,995,192	$66,719,631	57.5%	$230,697,196	87.3%	$244,550,556
Oct-13	$158,354,017	($94,365,761)	$63,988,256	$47,353,545	74.0%	$141,719,306	92.5%	$146,446,632
Nov-13	$156,649,135	($89,755,253)	$66,893,882	$44,748,426	66.9%	$134,503,679	89.9%	$140,751,323
Dec-13	$256,139,289	($140,195,812)	$115,943,477	$84,974,997	73.3%	$225,170,809	91.3%	$233,817,126
Total 2012/2013	$1,897,830,880	($990,471,801)	$907,359,079	$614,537,096	67.7%	$1,605,008,896	88.6%	$1,681,443,058
Total 2013/2014	$1,375,506,911	($756,306,146)	$619,200,765	$464,465,322	75.0%	$1,220,771,467	91.8%	$1,263,292,062

* Reported payout ratios may vary due to rounding differences when netting

Table 13-30 provides an example of how the counter flow adjustment method would impact a two FTR system. In this example there is $15 of total congestion revenue available, corresponding to a reported payout ratio of 75 percent and a monthly actual payout ratio of 87.5 percent. In the example, the profit before and after underfunding can be seen in addition to the profit after underfunding with the counter flow adjustment made. As illustrated, a counter flow FTR's profit does not change when underfunding is applied, whereas a prevailing flow FTR's profit decreases. Applying the counter flow adjustment distributes the underfunding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-31 shows the monthly positive, negative and total target allocations.[16] Table 13-31 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $42.5 million (27.5 percent of underfunding) in revenue available to fund positive target allocations for the first seven months of the 2013 to 2014 planning period.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the first seven months of the 2012 to 2013 planning period from the reported 75.0 percent to 91.8 percent.

16 Reported payout ratio may differ between Table 13-29 and Table 13-31 due to rounding differences when netting target allocations and considering each FTR individually.

Figure 13-20 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 2013.

Figure 13-20 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through December 2013

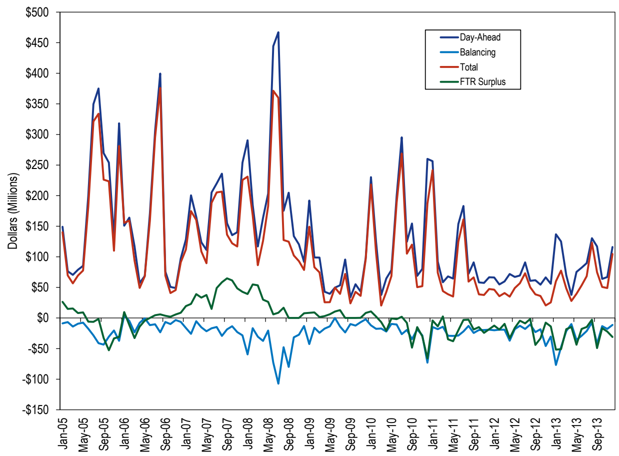
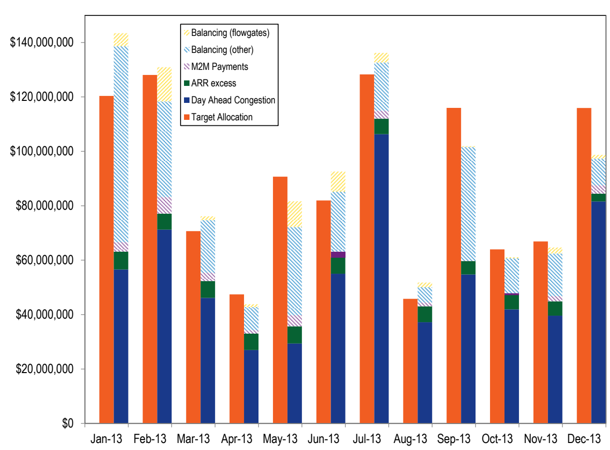


Figure 13-21 shows the relationship among balancing congestion, M2M payments and day-ahead congestion. In January 2013, balancing congestion not from flowgates contributed a large negative portion to FTR funding. In June and October, M2M payments were positive, providing revenue for FTR funding.

Figure 13-21 FTR target allocation compared to sources of positive and negative congestion revenue



Up-to-Congestion Impacts on FTR Funding

In order to study the impacts of UTCs on FTR funding, the Day-Ahead Market was rerun by PJM with and without UTC transactions for five days in May 2013.

Analysis of PJM's data from these reruns of the May 2, 4, 22, 23, 27 of 2013 day ahead market with and without UTC bids supports the hypothesis that UTC transactions contribute significantly to FTR underfunding.[17] The data indicate that removal of UTCs significantly improves FTR funding for each of the five days. FTR underfunding is a measure of the difference between total FTR target allocations and total congestion dollars available to fund FTRs. When FTR target allocations are greater than total congestion dollars, FTRs are considered underfunded, as FTR obligations are less than congestion dollars available. When FTR target allocations are less than congestion dollars available, FTRs are considered fully funded and there is a surplus of congestion dollars. Table 13-32 shows, for each study day, the actual FTR underfunding for the day, the FTR underfunding after the removal of UTC, the change in FTR underfunding caused by the removal of UTC from PJM's day ahead market model.

Analysis of PJM's data shows that for the five days studied, the removal of UTCs changed FTR funding relative to target allocations from a deficit of -$4.1 million to a net surplus of $537 thousand, a gain in funding relative to target allocations of $4.7 million. The magnitude of the effect depends on the day, but the results indicate that the removal of UTC takes PJM FTRs from a state of underfunding to a state of surplus in the five days studied.

Analysis of PJM's data from these reruns shows that removal of UTCs significantly decreases FTR target allocations on the five studied days. Target allocations are a function of FTR MW and the difference in the day ahead CLMP at the FTR source and sink bus. The removal of UTC bids significantly decreased day ahead congestion and CLMPs. This reduction in congestion and CLMPs reduced the target allocations of all FTRs. Table 13-32 shows, for each study day, the actual target allocations, the target allocations after the removal of UTC, and the change in target allocations caused by the

17 These conclusions are based on the five days selected by PJM and the system conditions on those days.

removal of UTC from PJM's day-ahead market model. PJM's data show that removing UTCs reduced the target allocations over the five study days by $8.5 million, or 52 percent.

Table 13-32 Changes in target allocations in PJM results by day: May 2, 4, 22, 23, 27 of 2013

Date	Actual Target Allocations	No UTC Target Allocations	Difference in Target Allocations	Change in Target Allocations
2-May-13	$1,361,464	$1,060,874	($300,590)	(22.1%)
4-May-13	$934,840	$137,589	($797,250)	(85.3%)
22-May-13	$7,002,555	$2,605,640	($4,396,915)	(62.8%)
23-May-13	$6,125,559	$3,779,988	($2,345,571)	(38.3%)
27-May-13	$817,088	$196,132	($620,956)	(76.0%)
Total	$16,241,505	$7,780,223	($8,461,282)	(52.1%)

The PJM data show that the inclusion of UTCs significantly increased total day ahead congestion compared to the case where there were no UTCs in the market, and significantly increased (made balancing charges more negative) the real time balancing congestion adjustment offset to day ahead total congestion compared to the case with no UTCs.

Table 13-33 Changes in FTR funding in PJM results by day: May 2, 4, 22, 23, 27 of 2013

	Actual Underfunding	No UTC Underfunding	Difference in Underfunding	Change in Underfunding
2-May-13	($456,443)	($424,086)	$32,358	(7.1%)
4-May-13	($305,854)	$124,345	$430,200	(140.7%)
22-May-13	($1,758,420)	$1,175,869	$2,934,289	(166.9%)
23-May-13	($1,874,367)	($631,962)	$1,242,406	(66.3%)
27-May-13	($38,119)	($24,031)	$14,089	(37.0%)
Total	($4,433,204)	$220,137	$4,653,341	(105.0%)

Up-to-Congestion Transaction FTR Forfeitures

Currently there is no FTR forfeiture rule implemented for up-to-congestion transactions (UTCs). A proposed tariff change that would apply the FTR forfeiture rule to UTCs is pending at FERC.[18] The FTR forfeiture rule should be applied to UTCs in the same way it is applied to INCs and DECs. The goal of the rule is to prevent the use of virtual bids (generally unprofitable virtual bids) to increase day-ahead congestion on an FTR path in order to increase the value of the FTRs. The proposed penalty should be the same as it is for the INC and DEC rule, the forfeiture of any profits from FTRs whose value is affected by a UTC with the same owner.

18 *See* FERC Docket No. ER13-1654.

However, the rule submitted by PJM, currently under review by FERC, would not be consistent with the application of the current forfeiture rule for INCs and DECs. Under PJM's proposed method the simple net dfax of the UTC transaction is the only consideration for forfeiture, representing the contract path of the UTC transaction. Under this method, the net dfax is the sink dfax of the UTC minus the source dfax of the UTC. The net dfax alone cannot be used as an indication of helping or hurting a constraint, rather, the direction of the constraint must also be considered. In addition, the PJM method only considers UTC transactions whose net dfax is positive. This logic not only passes transactions that should fail the forfeiture test, but fails transactions that should pass the forfeiture test.

PJM's logic also does not hold when one of the points of the UTC is far from the constraint. In this case, one side of the UTC would have a dfax of zero, indicating no connection to the constraint being considered. If a point of the UTC transaction has no connection to the constraint, there can be no power flow directly between the two UTC points, so the simple net dfax, which relies on the contract path of the UTC, cannot logically be used in this case to indicate whether a UTC is eligible for forfeiture. Under the MMU method this UTC would be treated as an INC or DEC and follow the same rules as the current INC/DEC FTR forfeiture rule.

Figure 13-22 shows an example of the two proposed FTR forfeiture rules for UTC transactions. In both cases, the net dfax of the UTC is taken. Under the PJM method the net dfax of the UTC is calculated by subtracting the dfax of the sink bus A (0.2) from the dfax of the source bus B (0.5) to get a net dfax of -0.3. If this net dfax value is greater than 0.75 the UTC is subject to forfeiture. Under the MMU method, the net dfax is calculated by subtracting the dfax of sink A (0.2) from the dfax of source bus B (0.5) to get a net dfax of 0.3. This net dfax is then compared to the withdrawal point with the largest impact on the constraint. The MMU method compares the net UTC dfax to a withdrawal because the UTC is a net injection. In this example, the net dfax is 0.3 and it is compared to the largest withdrawal dfax at C (-0.5). The absolute value of the difference is calculated from these two points to determine if the UTC fails the FTR forfeiture rule. In this case, the absolute value of the difference is the dfax of bus C (-0.5) minus the net UTC dfax (0.3) for a total impact of 0.8, which is over the

0.75 threshold for the FTR forfeiture rule. The result is that this UTC fails the FTR forfeiture rule. The MMU proposes to apply the same rules to UTC transactions as is applied to INCs and DECs, treat the UTC as equivalent to an INC or a DEC depending on its net impact. A UTC transaction is essentially a paired INC/DEC, it has a net impact on the flow across a constraint, as an INC or DEC does. While total system power balance is maintained by a UTC, local flows may change based on the UTC's net impact on a constraint. The MMU method captures this impact.

Figure 13-22 Illustration of UTC FTR forfeiture rule

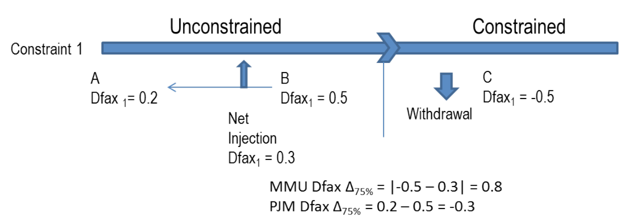
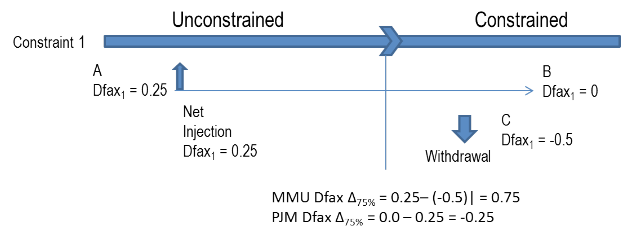


Figure 13-23 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to the constraint, as the other end of the UTC has no impact on the constraint. However, the PJM approach would not treat the UTC as an INC or DEC, despite the effective absence of the other end of the UTC. This is a flawed result.

As demonstrated in Figure 13-23, the UTC is no different than an INC on the constraint being considered. Using the PJM method this UTC would pass the FTR forfeiture rule. The net dfax would be calculated as the dfax of bus B (0) minus the dfax of bus A (0.25) for a net dfax of -0.25, with no comparison to any withdrawal bus. Since the dfax is negative, it would pass the PJM FTR forfeiture rule. Under the MMU's method, the net dfax is calculated as an injection with a dfax of 0.25, and then the absolute value of the difference is calculated between that injection and the dfax of the largest withdrawal on the constraint. In this example that is bus C, with a dfax of -0.5. The result is an absolute value of the dfax difference of 0.75, meaning that this UTC fails the FTR forfeiture test.

Figure 13-23 Illustration of UTC FTR Forfeiture rule with one point far from constraint



The MMU recommends that the FTR forfeiture rule be applied to UTCs in the same way it is applied to INCs and DECs.

Impact of ATSI Interface Constraint

The ATSI Interface was created by PJM effective July 17, 2013. It is not an interconnection reliability operating limit (IROL) transfer interface, which includes reactive transfer interfaces, nor does it reflect actual thermal transmission limits. The ATSI Interface, comprised of all the tie lines into the ATSI Control Zone,[19] was created by PJM in order to let emergency demand resources set real time prices in the ATSI Control Zone.

The creation of the ATSI Interface allows demand resources (DR) dispatched in the ATSI Control Zone to be marginal for providing energy during real-time emergency operations. The ATSI Interface is not defined or modeled in the Day-Ahead Energy Market and it cannot be defined in the Day-Ahead Energy Market because Emergency DR is not in the Day-Ahead Energy Market.

The ATSI interface constraint was binding in real time for four hours on July 18, for seven hours on September 10, and for eight hours on September 11, 2013. The ATSI interface constraint is not modeled in the Day-Ahead Energy Market and cannot set price in the Day-Ahead Energy Market.

The ATSI interface constraint resulted in $23.4 million in negative balancing congestion for those three days, reducing revenues available for FTR funding.

19 See PJM. "ATSI Interface" <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>.

A similar interface constraint to address constraint pricing in the BC-Pepco region was enforced in the Real-Time Energy Market on December 24, 2013, and not modeled in the Day-Ahead Market until December 27, 2013. The result was negative balancing congestion of $1.1 million, reducing revenues available for FTR funding. Once the BCPEP Interface was enforced in the Day-Ahead Market, balancing congestion returned to normal levels.

Creation of new constraints in the middle of a planning period that are not modeled in the Day-Ahead Energy Market creates underfunding. Constraints that are included in the Real-Time Energy Market but are not modeled in the Day-Ahead energy Market cause negative balancing congestion when they are binding. The addition of such constraints in the middle of a planning period results in FTR underfunding because it means that the facility limits in the area are now lower than when modeled, which is equivalent to over selling FTRs on affected paths.

PJM has indicated that it plans to implement several new interface constraints to modify pricing in certain areas.[20] PJM plans to incorporate these interfaces in the Annual FTR Auction for the 2014-2015 planning year.

PJM should not have the authority to decide when energy prices should be high in an entire zone, yet that is what PJM did when it established the ATSI Interface.[21] The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding. Regardless of the reason for implementing closed loop interfaces, such implementation and the impacts on FTR funding do not constitute a reason to require load to subsidize FTR funding. FTRs are a market product, purchased by participants who choose to take the risks associated with the product.

Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[22] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.

ARRs are available only as obligations (not options) and only as the 24-hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs

20 See PJM. "PJM Price-Setting Changes,"<http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx> (December 20, 2013).

21 See the *2013 State of the Market Report for PJM*, Volume 2, Section 3: Scarcity.

22 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.

are reallocated, as load shifts between LSEs within the transmission zone.

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[23] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers 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 the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2013 to 2014 planning period, all eligible market participants were allocated ARRs.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. The top ten binding transmission constraints for the 2013 to 2014 planning period are shown in Table 13-34.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[24] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis. Long Term ARR holders can self schedule their Long Term ARRs as FTRs for any planning period during the 10 planning period timeline.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.25
- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, 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 planning period covered by the allocation.

23 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

24 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

25 See PJM. "Manual 6: Financial Transmission Rights" Revision 15 (October 10, 2013), p. 22.

- **Stage 2.** Stage 2 of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[26] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing will be introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[27]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[28] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 13-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[29]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating only of ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs.

Table 13-34 shows the top 10 principal binding transmission constraints that limited the 2013 to 2014 Annual ARR Allocation. For the 2013 to 2014 ARR Stage 1A allocation, PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[30]

Table 13-34 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2013 to 2014

Constraint	Type	Control Zone
Cordova - Nelson	Flowgate	MISO
Silver Lake - Cherry Valley	Line	ComEd
Electric Junction - Nelson	Line	ComEd
Oak Grove - Galesburg	Flowgate	MISO
Waukegan-Zion	Line	ComEd
Zion - Lakeview	Line	ComEd
Lakeview	Transformer	MISO
Zion	Transformer	ComEd
Braidwood - East Frankfort	Line	ComEd
Greystone - West Wharton	Line	JCPL

26 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 21.

27 See "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx> The introduction of residual zone pricing, while approved by PJM members, depends on a FERC order.

28 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 55-56.

29 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

30 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[31] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to 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, when ARRs are self scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 35,501 MW of ARRs associated with approximately $233,800 of revenue that were reassigned for the first seven months of the 2013 to 2014 planning period.

Table 13-35 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2012 and December 2013.

Table 13-35 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2012, through December 31, 2013

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2012/2013 (12 months)	2013/2014 (7 months)*	2012/2013 (12 months)	2013/2014 (7 months)*
AECO	581	662	$3.0	$2.6
AEP	4,656	2,142	$58.9	$19.6
AP	3,518	1,492	$84.3	$31.5
ATSI	5,314	3,622	$8.3	$4.6
BGE	3,203	2,478	$37.3	$28.7
ComEd	11,824	6,079	$170.9	$63.0
DAY	589	881	$0.9	$1.6
DEOK	2,979	3,695	$1.6	$5.5
DLCO	2,708	4,137	$19.1	$9.3
DPL	1,989	1,415	$11.5	$12.8
Dominion	0	5	$0.0	$0.1
EKPC	NA	0	NA	$0.0
JCPL	1,373	884	$5.6	$3.9
Met-Ed	1,107	584	$8.6	$4.4
PECO	3,416	1,378	$22.8	$11.0
PENELEC	920	674	$8.3	$7.0
PPL	3,198	2,003	$20.7	$7.8
PSEG	2,313	1,385	$16.6	$13.8
Pepco	3,073	1,800	$21.4	$6.6
RECO	67	186	$0.0	$0.1
Total	52,825	35,501	$499.8	$233.8

* Through 31-Dec-2013

Incremental ARRs (IARRs) for RTEP Upgrades

Table 13-36 lists the incremental ARR allocation volume for the current and previous planning periods from the 2008 to 2009 planning period through the 2013 to 2014 planning period.

Table 13-36 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2013 to 2014

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	890.5	890.5	100%	0	0%
2009/2010	14	530.5	530.5	100%	0	0%
2010/2011	14	531.0	531.0	100%	0	0%
2011/2012	15	595.0	595.0	100%	0	0%
2012/2013	15	687.4	687.4	100%	0	0%
2013/2014	17	1,087.4	1,087.4	100%	0	0%

31 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 28.

Table 13-37 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs.

Table 13-37 IARRs allocated for 2013 to 2014 Annual ARR Allocation for RTEP upgrades[32]

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

Residual ARRs

Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs are available if additional transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any residual ARRs are available as ARRs in the annual ARR allocation. Stage 1 ARR holders have a priority right to ARRs. Residual ARRs are a separate product from incremental ARRs.

Effective August 1, 2012, as ordered by the FERC in Docket No. EL12-50-000, in addition to new transmission, residual ARRs are now available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. These residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation.

Table 13-38 shows the residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 13-38 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-13	6,773.0	1,547.2	22.8%	$488,251
Feb-13	1,567.4	1,493.7	95.3%	$229,856
Mar-13	5,351.2	1,522.7	28.5%	$286,193
Apr-13	5,452.1	1,608.9	29.5%	$325,662
May-13	6,054.7	1,647.4	27.2%	$282,425
Jun-13	10,864.1	1,272.7	11.7%	$667,291
Jul-13	10,936.9	1,323.7	12.1%	$714,675
Aug-13	9,357.2	767.2	8.2%	$236,885
Sep-13	1,855.0	402.9	21.7%	$85,884
Oct-13	1,555.3	411.5	26.5%	$27,639
Nov-13	1,393.5	564.1	40.5%	$116,103
Dec-13	2,343.6	1,686.7	72.0%	$186,383
Total	63,504.0	14,248.7	22.4%	$3,647,248

32 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following 10 pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03

Market Performance

Volume

Table 13-39 shows the volume of ARR allocations for each round of the 2012 to 2013 and 2013 to 2014 planning periods.

Table 13-39 Annual ARR Allocation volume: planning periods 2012 to 2013 and 2013 to 2014

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2012/2013	1A	0	16,069	67,302	67,300	100.0%	2	0.0%
	1B	1	11,487	30,013	18,432	61.4%	11,581	38.6%
	2	2	4,887	22,597	2,701	12.0%	19,896	88.0%
		3	3,682	22,496	3,334	14.8%	19,162	85.2%
		4	3,023	22,362	6,219	27.8%	16,143	72.2%
		Total	11,592	67,455	12,254	18.2%	55,201	81.8%
	Total		39,148	164,770	97,986	59.5%	66,784	40.5%
2013/2014	1A	0	18,022	67,861	67,861	100.0%	0	0.0%
	1B	1	14,227	32,679	15,782	48.3%	16,897	51.7%
	2	2	5,476	22,096	3,519	15.9%	18,577	84.1%
		3	4,128	22,480	3,200	14.2%	19,280	85.8%
		4	3,335	22,348	2,612	11.7%	19,736	88.3%
		Total	12,939	66,924	9,331	13.9%	57,593	86.1%
	Total		45,188	167,464	92,974	55.5%	74,490	44.5%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine transmission upgrades so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year of this test PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be included in the PJM RTEP process.

For the 2012 to 2013 planning period, Stage 1A of the Annual ARR Allocation was infeasible. According to Section 7.4.2 (i) of the PJM OATT the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and that these increased limits must then be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability.

The consequence of this increased capability in the models which does not reflect actual capability is an over allocation of both ARRs and FTRs for the entire planning period. In the case of ARRs this over allocation will lower the ARR funding level by selling more capability on the same transmission network. In the case of FTRs the over allocation will exacerbate the underfunding problem by selling more FTRs than are physically feasible with no increase in congestion collected.

Table 13-40 lists the constraints for which ARR requests were found to be infeasible for the 2012 to 2013 ARR Stage 1A Allocation and the MW increase in modeled facility ratings required to make them feasible. In addition, the reason for infeasibility is provided, whether it is an increase in network load, or due to transmission outages in the simultaneous feasibility test.

Table 13-40 Constraints with capacity increases due to Stage 1A infeasibility for the 2013 to 2014 ARR Allocation

Constraint	Contingency	Type	Zone	MW Increase	Reason
Silver Lake - Cherry Valley	Nelson - Electric Junction	Line	ComEd	251	Load
Cordova - Nelson	Nelson	Flowgate	MISO	215	Load
Electric Junction - Nelson	Nelson - Electric Junction	Line	ComEd	202	Load
Oak Grove - Galesburg	Nelson - Electric Junction	Flowgate	MISO	151	Load
Silver Lake - Cherry Valley	BASE	Line	ComEd	139	Load
Waukegan - Zion	BASE	Line	ComEd	129	Load
Zion	Cherry Valley - Silver Lake	Transformer	ComEd	121	Load
Zion - Lakeview	Cherry Valley - Silver Lake	Line	ComEd	121	Load
Lakeview	Cherry Valley - Silver Lake	Transformer	MISO	121	Load
Electric Junction - Nelson	BASE	Line	ComEd	113	Load
Waukegan - Zion	Cherry Valley - Silver Lake	Line	ComEd	106	Load
Roseland - Whippany	Roseland - Readington	Line	PSEG	103	Outages
Roseland - Whippany	BASE	Line	PSEG	93	Outages
Kenney - Mount Olive	New Church - Piney Grove	Line	DPL	70	Outages
Prairie State - W. Mt. Vernon	St Francis - Lutesville	Flowgate	MISO	60	Load
Kenney - Stockton	New Church - Piney Grove	Line	DPL	59	Outages
Mount Olive - Piney	New Church - Piney Grove	Line	DPL	54	Outages
Belvidere - Woodstock	Cherry Valley - Silver Lake	Line	ComEd	51	Load
Belvidere - Chrysler Corp.	Cherry Valley - Silver Lake	Line	ComEd	51	Load
Dixon - Stillman Valley	Nelson - Electric Junction	Line	ComEd	45	Load
Pleasant Valley - Belvidere 2	Cherry Valley - Silver Lake	Line	ComEd	41	Load
McGirr Road - Steward	Nelson - Electric Junction	Line	ComEd	37	Load
Athenia - Saddlebrook	BASE	Line	PSEG	24	Outages
Mazon - Mazon	Kickapoo Creek - Lasalle	Line	ComEd	16	Load
Pleasant Valley - Belvidere 1	Cherry Valley - Silver Lake	Line	ComEd	13	Load

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs.

The adequacy of ARRs as an offset to total congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs offset market participants' actual, total congestion into their zone. Customers that self schedule ARRs as FTRs provide the same offset to congestion as all other FTRs.

ARR holders received a projected $562.8 million in credits from the FTR auctions during the first seven months of the 2013 to 2014 planning period. During the first seven months of the 2012 to 2013 planning period, ARR holders received $620.2 million in ARR credits.

Table 13-41 lists projected ARR target allocations from the Annual ARR Allocation, and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period and the first seven months of the 2013 to 2014 planning periods.

Table 13-41 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

	2012/2013	2013/2014
Total FTR auction net revenue	$626.7	$562.8
Annual FTR Auction net revenue	$602.9	$558.4
Monthly Balance of Planning Period FTR Auction net revenue*	$23.9	$4.4
ARR target allocations	$570.5	$503.8
ARR credits	$570.5	$503.8
Surplus auction revenue	$56.2	$59.0
ARR payout ratio	100%	100%
FTR payout ratio*	67.8%	75.1%

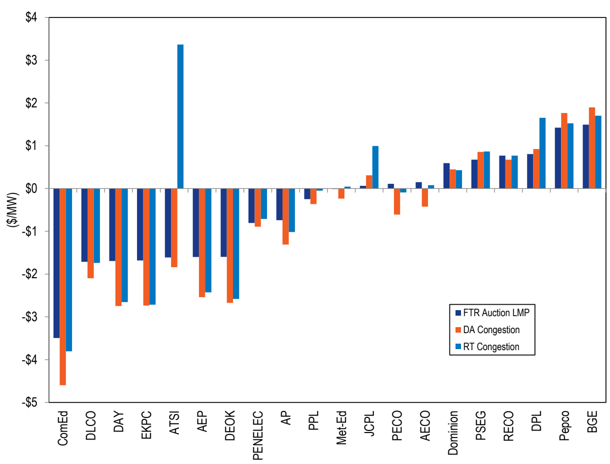
* Shows twelve months for 2012/2013 and seven months for 2013/2014.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 13-24 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the first seven months of the 2013 to 2014 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 13-24 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: 2013 to 2014 planning period through December 31, 2013



Effectiveness of ARRs as an Offset to Congestion

One measure of the effectiveness of ARRs as an offset to congestion is a comparison of the revenue received by the holders of ARRs and the congestion paid by the holders of ARRs in both the Day-Ahead Energy Market and the Balancing Energy Market. The revenue which serves as an offset for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments from the Day-Ahead Energy Market and the Balancing Energy Market. During the first seven months of the 2013 to 2014 planning period, the total revenues received by the holders of all ARRs and FTRs offset 100 percent of the total congestion costs within PJM.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the Balancing Energy Market is presented by control zone in Table 13-42. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[33] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the ARR credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self-scheduled FTR MW) and the cleared price for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and may be less than the target allocation. The FTR payout ratio was 75.1 percent of the target allocation for the first seven months of the 2013 to 2014 planning period. The target allocation is not a guarantee of payment nor does it reflect congestion incurred on a particular FTR path. The target allocation is used to set a cap on path specific FTR payouts.

ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total

33 For Table 13-42 through Table 13-44, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first seven months of the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

The Congestion column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the Balancing Energy Market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Table 13-42 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through December 31, 2013[34]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$4.1	$0.0	$4.1	$0.5	$3.6	>100%
AEP	$32.4	$28.9	$61.2	$3.7	$67.1	>100%
APS	$42.1	$12.9	$54.9	$0.1	$59.2	>100%
ATSI	$5.8	$0.1	$5.9	$0.5	$5.5	>100%
BGE	$29.3	$0.7	$30.0	$2.2	$28.0	>100%
ComEd	$74.6	$0.0	$74.6	$5.2	$69.4	>100%
DAY	$4.0	($0.0)	$4.0	($0.1)	$4.1	>100%
DEOK	$3.7	$0.6	$4.3	($0.1)	$4.6	>100%
DLCO	$1.9	$0.0	$1.9	($0.0)	$1.9	>100%
Dominion	$7.5	$33.9	$41.5	($0.1)	$52.8	>100%
DPL	$17.2	$1.8	$19.0	$1.4	$18.2	>100%
EKPC	$0.6	$0.1	$0.7	$0.1	$0.6	>100%
External	$2.3	$0.1	$2.3	$0.4	$1.9	>100%
JCPL	$6.6	$0.0	$6.6	$1.2	$5.4	>100%
Met-Ed	$6.8	$0.1	$6.9	$0.6	$6.4	>100%
PECO	$22.3	$0.0	$22.3	($0.4)	$22.7	>100%
PENELEC	$12.2	$0.0	$12.2	$0.6	$11.6	>100%
Pepco	$16.3	$1.8	$18.1	$2.7	$16.0	>100%
PPL	$10.0	$0.1	$10.1	$1.3	$8.8	>100%
PSEG	$36.6	$2.0	$38.5	$2.2	$37.0	>100%
RECO	$0.1	$0.0	$0.1	$0.1	$0.0	>100%
Total	$336.2	$88.7	$424.9	$22.1	$432.2	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-43 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the Balancing Energy Market for the first seven months of the 2013 to 2014 planning period. This compares the total offset provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the cleared price of the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions, and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 75.1 percent of the target allocation for the first seven months of the 2013 to 2014 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR offset is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the Balancing Energy Market in each control zone.[35] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

34 The "External" zone was labeled as "PJM" in previous State of the Market Reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM interfaces.

35 The total zonal congestion numbers were calculated as of January 27, 2014 and may change as a result of continued PJM billing updates.

Table 13-43 ARR and FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through December 31, 2013

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$4.1	$2.9	$4.9	$2.1	$4.2	($2.1)	49.5%
AEP	$83.5	$67.7	$103.3	$47.9	$76.4	($28.5)	62.7%
APS	$66.4	$23.7	$32.8	$57.2	$48.8	$8.4	>100%
ATSI	$5.9	$22.2	$0.9	$27.1	($18.7)	$45.8	>100%
BGE	$30.5	$26.1	$32.2	$24.4	$26.4	($2.0)	92.5%
ComEd	$84.1	$60.4	$56.7	$87.9	$106.5	($18.7)	82.5%
DAY	$4.0	$4.0	$3.9	$4.1	$2.5	$1.6	>100%
DEOK	$4.4	$4.1	$4.6	$3.9	($2.9)	$6.8	>100%
DLCO	$2.1	$1.2	$0.6	$2.7	$1.9	$0.8	>100%
Dominion	$94.9	$73.7	$134.5	$34.1	$49.0	($15.0)	69.5%
DPL	$19.3	$23.7	$15.1	$28.0	$18.0	$10.0	>100%
EKPC	$2.1	$0.4	$2.8	($0.3)	($1.9)	$1.6	0.0%
External	$2.8	$1.3	$1.9	$2.2	$3.4	($1.1)	66.0%
JCPL	$6.6	$19.8	$5.8	$20.5	$17.2	$3.3	>100%
Met-Ed	$6.9	$8.3	$7.8	$7.5	$2.6	$4.8	>100%
PECO	$22.4	$4.2	$18.5	$8.2	($9.7)	$17.9	>100%
PENELEC	$12.0	$27.1	$43.1	($4.0)	$19.7	($23.7)	0.0%
Pepco	$19.6	$47.8	$75.0	($7.6)	$44.9	($52.6)	0.0%
PPL	$10.1	$10.3	$0.3	$20.2	$4.3	$15.9	>100%
PSEG	$38.1	$39.4	$49.1	$28.3	$29.1	($0.8)	97.2%
RECO	$0.1	($0.4)	($1.0)	$0.7	$2.2	($1.5)	30.1%
Total	$519.9	$467.9	$592.9	$394.9	$423.9	($29.0)	93.2%

Table 13-44 shows the total offset due to ARRs and FTRs for the entire 2012 to 2013 and the first seven months of the 2013 to 2014 planning periods. ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Table 13-44 ARR and FTR congestion hedging (in millions): Planning periods 2012 to 2013 and 2013 to 2014[36]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2012/2013	$577.2	$610.3	$654.1	$533.4	$575.9	($42.5)	92.6%
2013/2014*	$519.9	$467.9	$592.9	$394.9	$423.9	($29.0)	93.2%

* Shows seven months ended December 31, 2013

36 The FTR credits do not include after-the-fact adjustments. For the 2013 to 2014 planning period, the ARR credits were the total credits allocated to all ARR of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the planning period and the portion of Annual FTR Auction revenue distributed to the entire planning period.