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 facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market.[2] In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

The *2014 Quarterly State of the Market Report for PJM: January through June*, focuses on the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period, covering January 1, 2014, through June 30, 2014.

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

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 the market design as implemented results in overselling FTRs. FTR funding levels are reduced as a result of these factors.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can sell FTRs. In the 2014 to 2015 Annual FTR Auction, total participant FTR sell offers were 271,368 MW, down from 417,118 MW in the 2013 to 2014 planning period. In the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, total participant FTR sell offers were 5,480,676 MW, up from 5,010,437 MW for the same period during the 2013 to 2014 planning period.

- **Demand.** There were 3,270,311 MW of buy and self-scheduled bids in the 2014 to 2015 Annual FTR Auction, down from 3,274,373 MW in the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 27.4 percent from 19,685,688 MW for the same time period of the prior planning period, to 25,088,665 MW.
- **Patterns of Ownership.** For the 2014 to 2015 Annual FTR Auction, financial entities purchased 57.5 percent of prevailing flow FTRs and 80.0 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 78.1 percent of prevailing flow and 87.4 percent of counter flow FTRs for January through June of 2014. Financial entities owned 69.7 percent of all prevailing and counter flow FTRs, including 60.1 percent of all prevailing flow FTRs and 85.7 percent of all counter flow FTRs during the period from January through June 2014.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $1,214,878 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.
- **Credit Issues.** People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[3]

  Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, in January through March 2014, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. In April through June 2014, CCES, LLC defaulted again for a total of $59,899. The default allocation assessment was assigned to non-defaulting members resulting in 18 payment defaults in April 2014 totaling $4,017, nine of which were promptly cured. There were no collateral or payment defaults in May or June 2014. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** In the Annual FTR Auction for the 2014 to 2015 planning period, 365,843 MW (11.2 percent) of buy and self-schedule bids cleared. For the 2013 to 2014 planning period Monthly Balance of Planning Period FTR Auctions 3,414,500 MW (13.6 percent) of FTR buy bids and 1,153,835 MW (21.1 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid FTR price for the 2014 to 2015 Annual FTR Auction was $0.29 per MW, up from $0.13 per MW in the 2013 to 2014 planning period. The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period was $0.17, up from $0.10 per MW in the 2013 to 2014 planning period.
- **Revenue.** The 2014 to 2015 Annual FTR Auction generated $748.6 million in net revenue, up $190.2 million from the 2013 to 2014 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $29.8 million in net revenue for all FTRs for the 2013 to 2014

3 *See* Default Allocation Assessment. OATT Section 15.2.2

planning period, up from $23.9 million for the same time period in the 2012 to 2013 planning period.

- **Revenue Adequacy.** FTRs were paid at 72.8 percent of the target allocation level for the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on their portion of FTR target allocations. PJM collected $1,819.5 million of FTR revenues during the 2013 to 2014 planning period and $614.0 million during the 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 Dominion Zone and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the Western Hub.

  For the first six months of 2014, total day-ahead congestion was $1,679.2 million while total day-ahead plus balancing congestion was $1,429.5 million, compared to target allocations of $1,965.7 million in the same time period.

  Target allocation 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. Actual congestion incurred is the overpayment by load compared to payments to generation which result from both day-ahead congestion and balancing congestion. 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. Target allocations are just a distribution mechanism for congestion collected.

- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 98.2 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for 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 $720.4 million in profits for physical entities, of which $355.1 million was from self-scheduled FTRs, and $495.1 million for financial entities. FTRs were undervalued in the auctions compared to their returns from congestion revenue, despite the fact that the payout ratio was less than 1.0. Not every FTR was profitable. FTR profits were high for the first six months of 2014 due in large part to very high January congestion prices and higher than normal congestion prices in February and March.

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 2013 to 2014 planning period planning period PJM allocated a total of 15,417.5 MW of residual ARRs with a total target allocation of $4,683,134.

- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 64,086 MW of ARRs associated with $382,100 of revenue that were reassigned for the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the 2013 to 2014 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $520.0 million while PJM collected $593.9 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 2013 to 2014 planning period and for the 2012 to 2013 planning period.

Recommendations

- Report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants.
- Eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs.
- Eliminate geographic cross subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation 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 closed loop 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, if there is good reason to implement, 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.

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. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

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.[4] 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, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, 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.

Reported FTR revenue sufficiency uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring the other part of total congestion which is balancing congestion. The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For the first six months of 2014, total day-ahead congestion was $1,679.2 million while total day-ahead plus balancing congestion was $1,429.5 million, compared to target allocations of $1,965.7 million in the same time period.

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 2014, the bid volume was 9,600,316 MW (a 405.7 percent increase) and the net bid volume was 8,631,332 MW (a 368.1 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.90 in June 2014, indicating an increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM is understated. The PJM reported monthly payout ratio does not appropriately consider negative target

4 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC" EL13-47(February 15, 2013).

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. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8 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 impact of lower payouts 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 FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR over allocation would increase the payout ratio to 94.6 percent.

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 a difference between congestion revenue and the payment obligation; 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 the differences between day-ahead and balancing congestion and thus to FTR payout ratios; and the continued sale of FTR capability on pathways with a persistent difference between FTRs and total congestion revenue. 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. But, 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. 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. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. 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, payments by holders of negatively valued FTRs, Market to Market payments, excess ARR revenues available at the end of a month and any charges made to day-ahead operating reserves. Depending on the amount of revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations.

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.

FTRs can be bought, sold and self scheduled. Buy bids are bids to buy FTRs in the auctions; sell offers are offers to sell existing FTRs 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.

The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

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.

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.[5] 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.[6]

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.

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

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

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.[7]

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 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 2014 to 2015 Annual FTR Auction were 3,270,311 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period were 25,088,665 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 13-2 presents the Annual FTR Auction cleared FTRs for the 2014 to 2015 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2014 to 2015 planning period, financial entities purchased 57.5 percent of prevailing flow FTRs and 80.0 percent of counter flow FTRs, with the result that financial entities purchased 64.4 percent of all Annual FTR Auction cleared buy bids for the 2014 to 2015 planning period.

Table 13-2 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2014 to 2015

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	10.4%	0.6%	7.4%
		No	32.1%	19.5%	28.2%
		Total	42.5%	20.0%	35.6%
	Financial	No	57.5%	80.0%	64.4%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		28.2%	25.4%	27.4%
	Financial		71.8%	74.6%	72.6%
	Total		100.0%	100.0%	100.0%

Table 13-3 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through June 2014 by trade type, organization type and FTR direction. Financial entities purchased 78.1 percent of prevailing flow and 87.4 percent of counter flow FTRs for the year, with the result that financial entities purchased 81.4 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through June 2014.

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

Table 13-3 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through June 2014

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	21.9%	12.6%	18.6%
	Financial	78.1%	87.4%	81.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	31.3%	35.9%	32.1%
	Financial	68.7%	64.1%	67.9%
	Total	100.0%	100.0%	100.0%

Table 13-4 presents the daily net position ownership for all FTRs for January through June 2014, by FTR direction.

Table 13-4 Daily FTR net position ownership by FTR direction: January through June 2014

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	39.9%	14.3%	30.3%
Financial	60.1%	85.7%	69.7%
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 13-1 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 13-1, 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 13-1 Illustration of INC/DEC FTR forfeiture rule

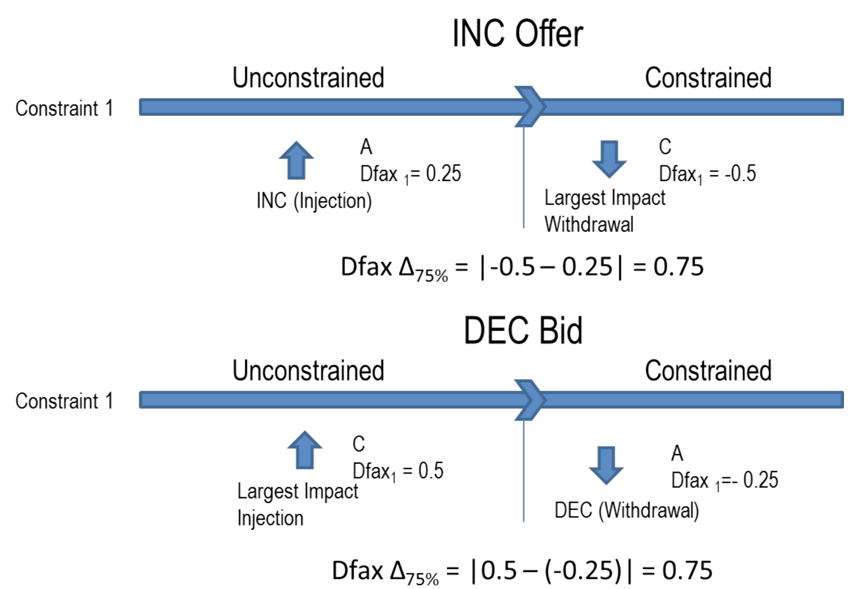


Figure 13-2 shows the FTR forfeiture values for both physical and financial participants for each month of June 2010 through May 2014. Currently, FTRs that alleviate a constraint are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2013 to 2014 planning period were $1.2 million (0.05 percent of total FTR target allocations).

Figure 13-2 Monthly FTR forfeitures for physical and financial participants: June 2010 through May 2014

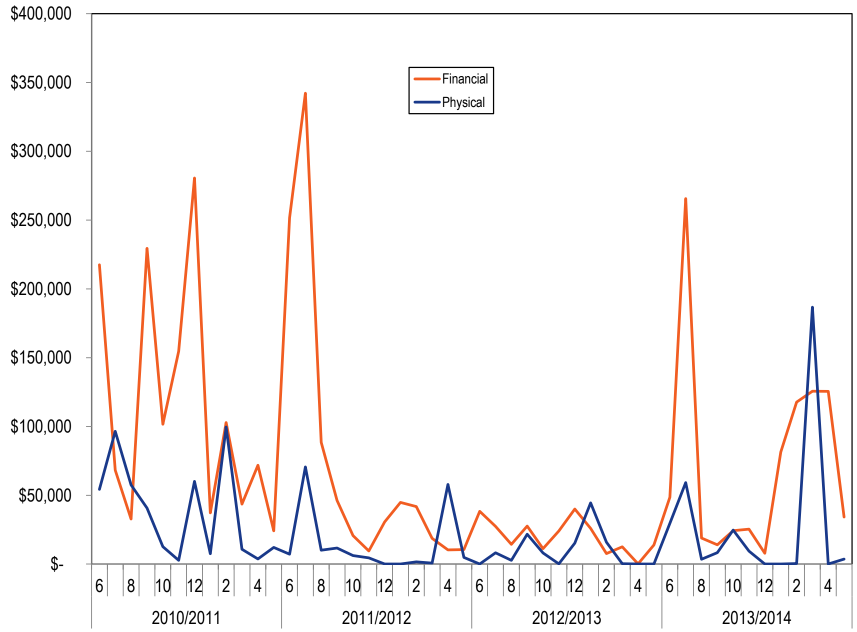
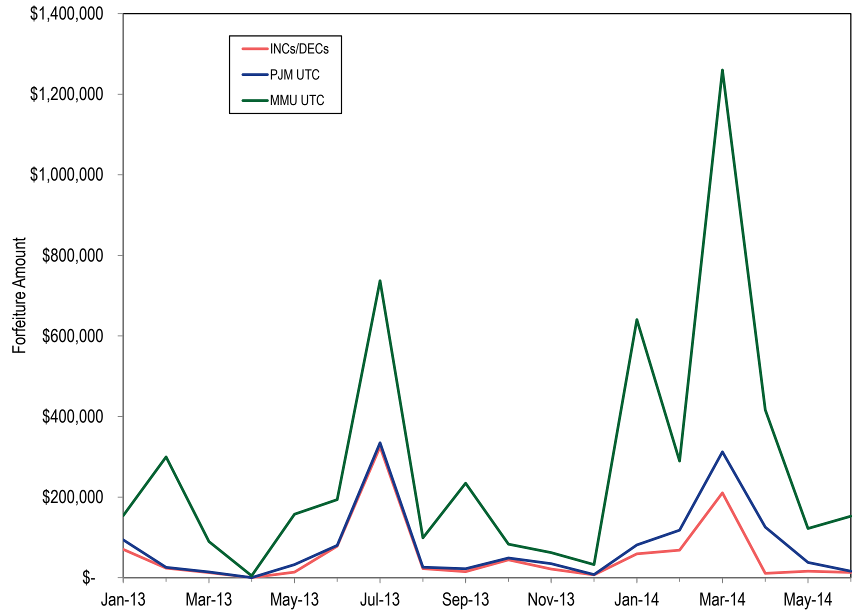


Figure 13-3 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through June 2014. The method proposed by PJM for calculating forfeitures 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 13-3 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through June 2014



Credit Issues

People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6

million. On March 6, 2014, PJM filed with the FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[8]

Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, in January through March 2014, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. In April through June 2014, CCES, LLC defaulted again for a total of $59,899. Also, the default allocation assessment was assigned to non-defaulting members resulting in 18 payment defaults in April 2014 totaling $4,017, nine of which were promptly cured. There were no collateral or payment defaults in May or June 2014. These defaults were not necessarily related to FTR positions.

Market Performance

Volume

In an effort to address reduced FTR payout ratios 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 MW of Stage 1A infeasibility and the availability of appropriate auction bids. Reducing capability limits will reduce the number of oversold FTR facilities due to forced Stage 1A infeasibilities and reduce the FTR funding issues caused by these ARR infeasibilities. The downside to this strategy is that there will be fewer 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 funding issues, 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. This reduction may only take place when there are auction bids available to reduce the infeasibilities. The results of this action should be an increased feasibility of the FTR model, but a reduction in FTR Auction revenue due to a lower capability.

Table 13-5 provides the Annual FTR Auction market volume for the 2014 to 2015 planning period. Total FTR buy bids were 3,270,311 MW, down 0.1 percent from 3,274,373 MW for the previous planning period. For the 2014 to 2015 planning period 365,843 MW (11.2 percent) of buy bids cleared, down 6.5 percent from 391,148 MW for the previous planning period. There were 271,368 MW of sell offers with 41,213 MW (15.2 percent) clearing for the 2014 to 2015 planning period.

8 *See* Default Allocation Assessment. OATT Section 15.2.2

Table 13-5 Annual FTR Auction market volume: Planning period 2014 to 2015

Trade Type	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	80,967	396,560	111,106	28.0%	285,454	72.0%
		Prevailing Flow	290,281	1,753,845	218,452	12.5%	1,535,393	87.5%
		Total	371,248	2,150,405	329,558	15.3%	1,820,847	84.7%
	Options	Counter Flow	127	6,290	607	9.7%	5,683	90.3%
		Prevailing Flow	68,800	1,086,651	8,714	0.8%	1,077,937	99.2%
		Total	68,927	1,092,942	9,321	0.9%	1,083,620	99.1%
	Total	Counter Flow	81,094	402,850	111,713	27.7%	291,137	72.3%
		Prevailing Flow	359,081	2,840,496	227,166	8.0%	2,613,331	92.0%
		Total	440,175	3,243,346	338,879	10.4%	2,904,468	89.6%
Self-scheduled bids	Obligations	Counter Flow	26	626	626	100.0%	0	0.0%
		Prevailing Flow	2,894	26,339	26,339	100.0%	0	0.0%
		Total	2,920	26,965	26,965	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	80,993	397,186	111,732	28.1%	285,454	71.9%
		Prevailing Flow	293,175	1,780,184	244,791	13.8%	1,535,393	86.2%
		Total	374,168	2,177,369	356,522	16.4%	1,820,847	83.6%
	Options	Counter Flow	127	6,290	607	9.7%	5,683	90.3%
		Prevailing Flow	68,800	1,086,651	8,714	0.8%	1,077,937	99.2%
		Total	68,927	1,092,942	9,321	0.9%	1,083,620	99.1%
	Total	Counter Flow	81,120	403,476	112,339	27.8%	291,137	72.2%
		Prevailing Flow	361,975	2,866,835	253,505	8.8%	2,613,331	91.2%
		Total	443,095	3,270,311	365,843	11.2%	2,904,468	88.8%
Sell offers	Obligations	Counter Flow	38,483	97,248	11,502	11.8%	85,746	88.2%
		Prevailing Flow	71,590	171,613	29,609	17.3%	142,004	82.7%
		Total	110,073	268,861	41,111	15.3%	227,750	84.7%
	Options	Counter Flow	24	460	0	0.0%	460	100.0%
		Prevailing Flow	221	2,047	102	5.0%	1,945	95.0%
		Total	245	2,507	102	4.1%	2,405	95.9%
	Total	Counter Flow	38,507	97,708	11,502	11.8%	86,206	88.2%
		Prevailing Flow	71,811	173,660	29,711	17.1%	143,949	82.9%
		Total	110,318	271,368	41,213	15.2%	230,155	84.8%

Table 13-6 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2013 to 2014 planning period and the first month of the 2014 to 2015 planning period. There were 2,711,522 MW of FTR obligation buy bids and 363,039 MW of FTR obligation sell offers for all bidding periods in the first month of the 2014 to 2015 planning period. The monthly balance of planning period auctions cleared 220,555 MW (8.1 percent) of FTR obligation buy bids and 75,427 MW (20.8 percent) of FTR obligation sell offer.

There were 545,575 MW of FTR option buy bids and 18,521 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first month of the 2014 to 2015 planning period. The monthly auctions cleared 3,726 (0.7 percent) of FTR option buy bids, and 6,929 MW (37.4 percent) of FTR option sell offers.

Table 13-6 Monthly Balance of Planning Period FTR Auction market volume: January through June 2014

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-14	Obligations	Buy bids	235,126	1,793,756	257,472	14.4%	1,536,283	85.6%
		Sell offers	103,912	286,684	45,850	16.0%	240,834	84.0%
	Options	Buy bids	6,536	298,300	7,805	2.6%	290,495	97.4%
		Sell offers	14,893	92,294	34,143	37.0%	58,151	63.0%
Feb-14	Obligations	Buy bids	235,697	1,578,788	239,877	15.2%	1,338,911	84.8%
		Sell offers	122,726	315,024	53,406	17.0%	261,619	83.0%
	Options	Buy bids	9,970	400,903	5,716	1.4%	395,187	98.6%
		Sell offers	12,801	75,859	35,021	46.2%	40,837	53.8%
Mar-14	Obligations	Buy bids	208,029	1,544,652	251,291	16.3%	1,293,361	83.7%
		Sell offers	107,355	274,653	50,275	18.3%	224,378	81.7%
	Options	Buy bids	11,027	373,373	10,379	2.8%	362,994	97.2%
		Sell offers	13,120	83,295	41,895	50.3%	41,400	49.7%
Apr-14	Obligations	Buy bids	164,728	1,358,802	213,902	15.7%	1,144,899	84.3%
		Sell offers	98,116	260,343	63,628	24.4%	196,715	75.6%
	Options	Buy bids	4,617	201,185	6,439	3.2%	194,746	96.8%
		Sell offers	8,699	52,533	29,277	55.7%	23,256	44.3%
May-14	Obligations	Buy bids	116,589	829,477	134,897	16.3%	694,580	83.7%
		Sell offers	46,426	147,043	36,569	24.9%	110,473	75.1%
	Options	Buy bids	2,585	105,367	3,312	3.1%	102,055	96.9%
		Sell offers	4,186	30,447	21,039	69.1%	9,408	30.9%
Jun-14	Obligations	Buy bids	372,164	2,711,522	220,555	8.1%	2,490,966	91.9%
		Sell offers	174,060	363,039	75,427	20.8%	287,612	79.2%
	Options	Buy bids	28,961	545,575	3,746	0.7%	541,829	99.3%
		Sell offers	3,136	18,521	6,929	37.4%	11,592	62.6%
2013/2014*	Obligations	Buy bids	2,981,219	20,739,786	3,284,056	15.8%	17,455,730	84.2%
		Sell offers	1,513,626	4,166,671	681,264	16.4%	3,485,407	83.6%
	Options	Buy bids	93,770	4,348,879	130,444	3.0%	4,218,435	97.0%
		Sell offers	188,618	1,314,005	472,571	36.0%	841,435	64.0%
2014/2015**	Obligations	Buy bids	372,164	2,711,522	220,555	8.1%	2,490,966	91.9%
		Sell offers	174,060	363,039	75,427	20.8%	287,612	79.2%
	Options	Buy bids	28,961	545,575	3,746	0.7%	541,829	99.3%
		Sell offers	3,136	18,521	6,929	37.4%	11,592	62.6%

* Shows Twelve Months for 2013/2014; ** Shows one month ended 30-Jun-14 for 2014/2015

Table 13-7 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 June 2014 was 225,898.5 MW. The average monthly cleared volume for January through June 2013 was 257,513.3 MW.

Table 13-7 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through June 2014

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-14	Bid	955,235	415,803	335,298				385,720	2,092,055
	Cleared	171,036	42,816	21,423				30,002	265,277
Feb-14	Bid	960,803	349,289	340,651				328,949	1,979,691
	Cleared	158,160	30,891	23,446				33,096	245,593
Mar-14	Bid	1,021,453	362,479	380,157				153,936	1,918,025
	Cleared	184,026	38,011	30,016				9,616	261,670
Apr-14	Bid	1,161,109	398,878						1,559,987
	Cleared	178,584	41,758						220,341
May-14	Bid	934,844							934,844
	Cleared	138,209							138,209
Jun-14	Bid	1,021,130	430,585	413,652	240,150	401,266	393,290	357,024	3,257,096
	Cleared	106,450	21,444	21,044	9,429	23,422	24,475	18,036	224,301

Figure 13-4 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through June 2014, 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 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through June 2014

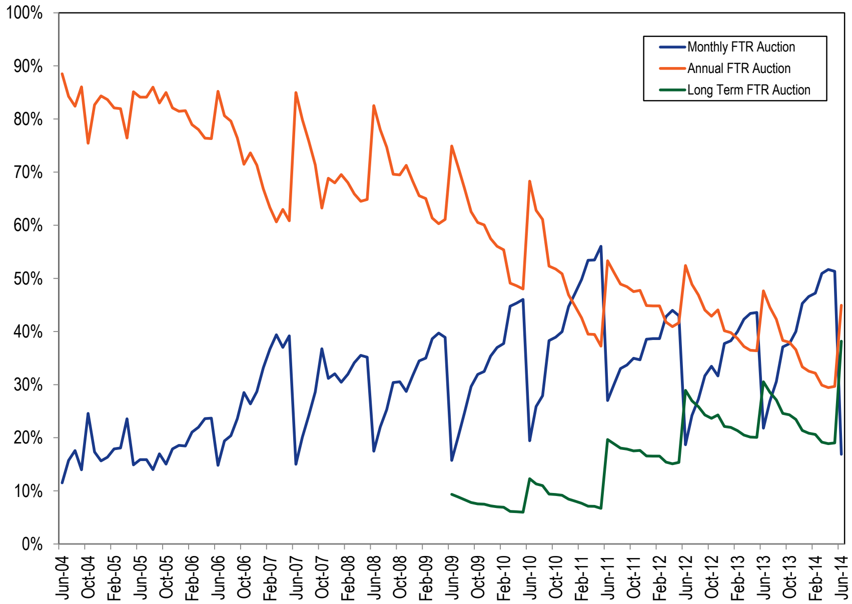


Table 13-8 provides the secondary bilateral FTR market volume for the entire 2012 to 2013 and 2013 to 2014 planning periods.

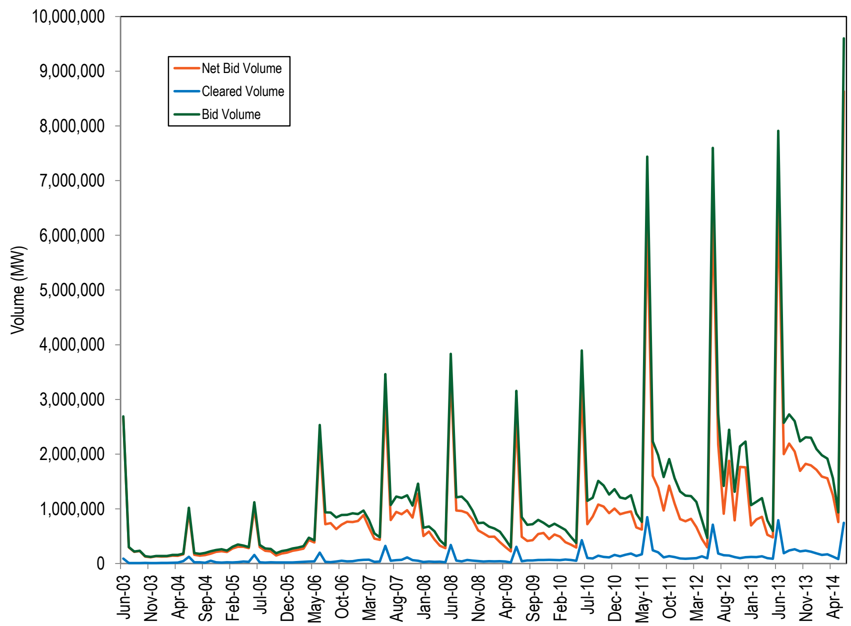
Table 13-8 Secondary bilateral FTR market volume: Planning periods 2012 to 2013 and 2013 to 2014[9]

Planning Period	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	43,495
		Off Peak	36,012
		Total	79,617
	Option	24-Hour	0
		On Peak	9,724
		Off Peak	914
		Total	10,638

Figure 13-5 shows the FTR bid, cleared and net bid volume from June 2003 through June 2014 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. In 2013 cleared volume increased, and there was a larger increase in 2014. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

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

Figure 13-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through June 2014



Price

Table 13-9 shows the weighted-average cleared buy-bid prices by trade type, type, FTR direction and class type for the Annual FTR Auction for the 2014 to 2015 planning period. The weighted-average buy-bid FTR price in the 2014 to 2015 Annual FTR Auction was $0.29 per MW, up from $0.13 per MW in the 2013 to 2014 planning period.

Table 13-9 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2014 to 2015

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.45)	($0.47)	($0.20)	($0.33)
		Prevailing Flow	$1.08	$0.79	$0.40	$0.65
		Total	$0.79	$0.37	$0.19	$0.33
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.28	$0.42	$0.20	$0.29
		Total	$0.28	$0.42	$0.20	$0.29
Self-scheduled bids	Obligations	Counter Flow	($0.05)	NA	NA	($0.05)
		Prevailing Flow	$1.23	NA	NA	$1.23
		Total	$1.20	NA	NA	$1.20
Buy and self-scheduled bids	Obligations	Counter Flow	($0.39)	($0.47)	($0.20)	($0.33)
		Prevailing Flow	$1.18	$0.79	$0.40	$0.76
		Total	$1.04	$0.37	$0.19	$0.44
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.28	$0.42	$0.20	$0.29
		Total	$0.28	$0.42	$0.20	$0.29
Sell offers	Obligations	Counter Flow	($0.20)	($0.49)	($0.50)	($0.49)
		Prevailing Flow	$1.10	$0.60	$0.31	$0.47
		Total	$0.66	$0.36	$0.07	$0.22
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.52	$0.16	$0.39
		Total	$0.00	$0.52	$0.16	$0.39

Table 13-10 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2014 through June 2014. For example, for the January 2014 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 June 2014 was $0.17 per MW, up from $0.12 per MW in the same time last year.

Table 13-10 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through June 2014

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-14	$0.11	$0.12	$0.08				$0.05	$0.09
Feb-14	$0.31	$0.22	$0.10				$0.13	$0.22
Mar-14	$0.19	$0.18	$0.17				$0.17	$0.19
Apr-14	$0.18	$0.20						$0.18
May-14	$0.17	$0.00						$0.17
Jun-14	$0.14	$0.26	$0.20	$0.22	$0.12	$0.15	$0.11	$0.15

Profitability

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 13-11 lists FTR profits by organization type and FTR direction for the period from January through June 2014. 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 which are very small and do not occur in every month. 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. Self-scheduled FTRs have zero cost. FTRs were profitable overall, with $720.4 million in profits for physical entities, of which $357.1 million was from self-scheduled FTRs, and $495.1 million for financial entities.

Table 13-11 FTR profits by organization type and FTR direction: January through June 2014

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$434,581,736	$357,064,643	($69,243,024)	($2,048,619)	$720,354,735
Financial	$510,916,571	NA	($15,818,047)	NA	$495,098,524
Total	$945,498,306	$357,064,643	($85,061,070)	($2,048,619)	$1,215,453,260

Table 13-12 lists the monthly FTR profits in the first six months of 2014 by organization type.

Table 13-12 Monthly FTR profits by organization type: January through June 2014

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$249,622,111	$180,379,965	$284,346,392	$714,348,467
Feb	$51,128,624	$39,339,259	$50,029,319	$140,497,202
Mar	$52,904,642	$80,420,488	$92,975,434	$226,300,564
Apr	$2,575,191	$13,269,781	$29,611,277	$45,456,249
May	$4,488,987	$14,781,066	$25,211,798	$44,481,851
Jun	$4,619,156	$26,825,465	$12,924,305	$44,368,926
Total	$365,338,712	$355,016,023	$495,098,524	$1,215,453,260

Revenue

Annual FTR Auction Revenue

Table 13-13 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2014 to 2015 planning period generated $748.6 million, up 34.1 percent from $558.4 million in the 2013 to 2014 planning period, and up 24.2 percent from the 2012 to 2013 planning period. Counter flow FTR holders received $142.4 million, up 93.7 percent from the previous planning period, from the auction and prevailing flow FTR holders paid $891.0 million, up 41.0 percent from the previous planning period.

Table 13-13 Annual FTR Auction revenue: Planning period 2014 to 2015

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($12,748,731)	($101,680,766)	($50,876,827)	($165,306,324)
		Prevailing Flow	$129,839,493	$340,430,995	$188,514,968	$658,785,457
		Total	$117,090,762	$238,750,229	$137,638,141	$493,479,132
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,698,504	$6,724,374	$4,364,294	$12,787,172
		Total	$1,698,504	$6,724,374	$4,364,294	$12,787,172
	Total	Counter Flow	($12,748,731)	($101,680,766)	($50,876,827)	($165,306,324)
		Prevailing Flow	$131,537,997	$347,155,370	$192,879,262	$671,572,629
		Total	$118,789,266	$245,474,603	$142,002,435	$506,266,304
Self-scheduled bids	Obligations	Counter Flow	($292,785)	NA	NA	($292,785)
		Prevailing Flow	$283,762,840	NA	NA	$283,762,840
		Total	$283,470,055	NA	NA	$283,470,055
Buy and self-scheduled bids	Obligations	Counter Flow	($13,041,516)	($101,680,766)	($50,876,827)	($165,599,109)
		Prevailing Flow	$413,602,333	$340,430,995	$188,514,968	$942,548,296
		Total	$400,560,817	$238,750,229	$137,638,141	$776,949,187
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,698,504	$6,724,374	$4,364,294	$12,787,172
		Total	$1,698,504	$6,724,374	$4,364,294	$12,787,172
	Total	Counter Flow	($13,041,516)	($101,680,766)	($50,876,827)	($165,599,109)
		Prevailing Flow	$415,300,836	$347,155,370	$192,879,262	$955,335,468
		Total	$402,259,321	$245,474,603	$142,002,435	$789,736,359
Sell offers	Obligations	Counter Flow	($474,559)	($8,884,397)	($13,823,174)	($23,182,130)
		Prevailing Flow	$4,981,741	$39,221,394	$19,929,734	$64,132,869
		Total	$4,507,182	$30,336,996	$6,106,561	$40,950,739
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$142,086	$26,192	$168,278
		Total	$0	$142,086	$26,192	$168,278
	Total	Counter Flow	($474,559)	($8,884,397)	($13,823,174)	($23,182,130)
		Prevailing Flow	$4,981,741	$39,363,480	$19,955,926	$64,301,147
		Total	$4,507,182	$30,479,083	$6,132,752	$41,119,017
Total			$397,752,139	$214,995,521	$135,869,683	$748,617,342

Figure 13-6 shows the weighted-average cleared buy-bid price frequency for the 2014 to 2015 Annual FTR Auction. Of the Annual FTRs, 85.1 percent were purchased for less than $1 per MW.

Figure 13-6 Annual FTR Auction clearing price per MW: Planning period 2014 to 2015

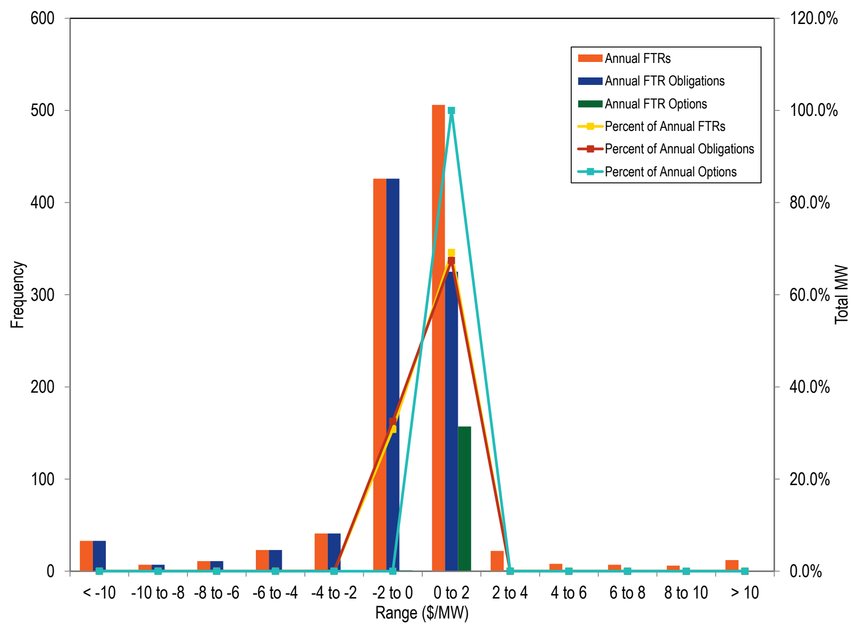


Figure 13-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2014 to 2015

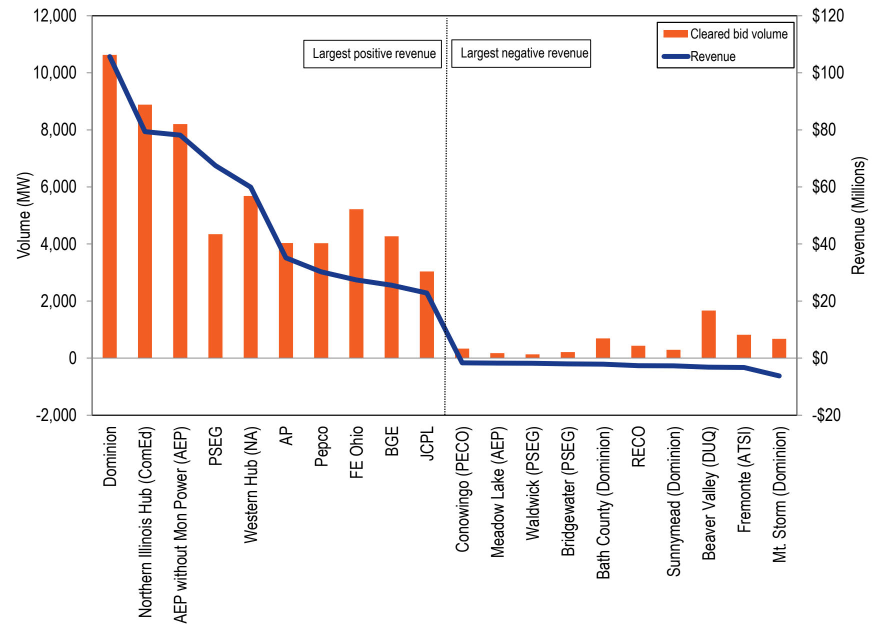
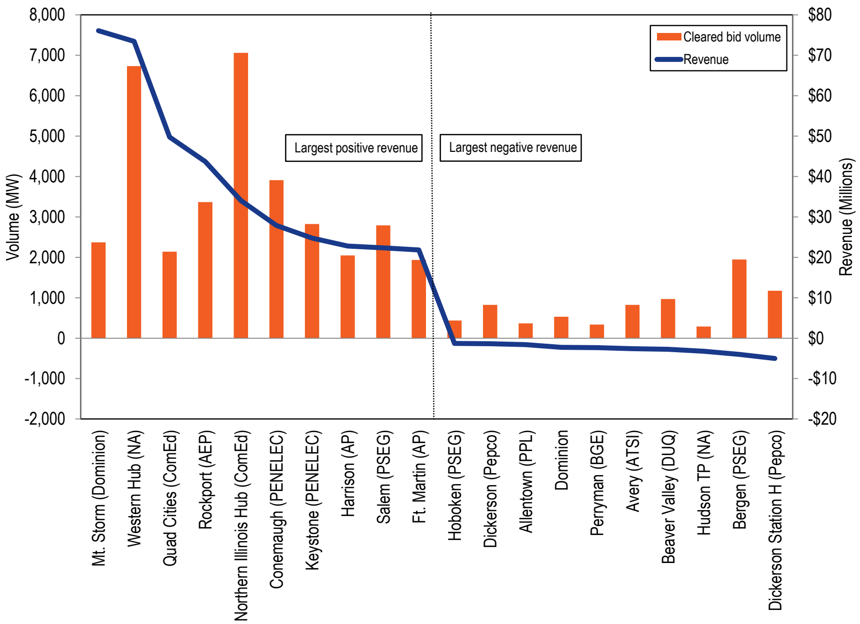


Figure 13-7 summarizes the total revenue associated with all FTR sink points regardless of source, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2014 to 2015 planning period. The top ten positive revenue sinks accounted for 71.0 percent of total revenue. The top ten negative revenue sinks accounted for 3.7 percent of total revenue.

Figure 13-8 summarizes the total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2014 to 2015 planning period. The top ten positive revenue sources accounted for 53.0 percent of total revenue. The top ten negative revenue sources accounted for 3.5 percent of total revenue.

Figure 13-8 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2014 to 2015



Monthly Balance of Planning Period FTR Auction Revenue

Table 13-14 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through June 2014. The Monthly Balance of Planning Period FTR Auction netted $1.9 million in revenue, with buyers paying $20.8 million and sellers receiving $18.9 million for the first month of the 2014 to 2015 planning period. For the entire 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions netted $29.8 million in revenue with buyers paying $206.9 million and sellers receiving $177.1 million.

Table 13-14 Monthly Balance of Planning Period FTR Auction revenue: January through June 2014

			Class Type			
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-14	Obligations	Buy bids	$538,610	$6,544,992	$3,406,763	$10,490,364
		Sell offers	$255,974	$3,772,022	$2,170,525	$6,198,521
	Options	Buy bids	$0	$495,869	$277,203	$773,072
		Sell offers	$0	$2,607,255	$2,450,896	$5,058,152
Feb-14	Obligations	Buy bids	$772,337	$13,639,753	$8,949,253	$23,361,343
		Sell offers	$861,314	$8,562,236	$6,040,336	$15,463,885
	Options	Buy bids	$0	$530,102	$628,647	$1,158,749
		Sell offers	$7,752	$4,398,077	$3,362,318	$7,768,147
Mar-14	Obligations	Buy bids	$1,279,408	$9,929,162	$6,943,023	$18,151,593
		Sell offers	$674,564	$6,152,784	$3,794,533	$10,621,881
	Options	Buy bids	$0	$959,329	$699,358	$1,658,688
		Sell offers	$13,013	$3,653,094	$2,937,076	$6,603,182
Apr-14	Obligations	Buy bids	$1,730,553	$7,258,667	$5,042,410	$14,031,631
		Sell offers	$483,489	$4,812,099	$2,767,189	$8,062,776
	Options	Buy bids	$0	$476,073	$303,342	$779,415
		Sell offers	$0	$2,455,211	$2,261,171	$4,716,382
May-14	Obligations	Buy bids	$199,961	$4,707,719	$3,063,318	$7,970,998
		Sell offers	$1,103,488	$2,672,060	$1,874,957	$5,650,505
	Options	Buy bids	$0	$401,410	$428,029	$829,439
		Sell offers	$0	$1,649,823	$1,446,271	$3,096,093
Jun-14	Obligations	Buy bids	$1,370,874	$11,646,070	$6,989,461	$20,006,404
		Sell offers	$3,279,375	$7,756,077	$5,507,835	$16,543,287
	Options	Buy bids	$0	$429,965	$404,600	$834,565
		Sell offers	$11,621	$1,391,691	$959,140	$2,362,452
2013/2014*	Obligations	Buy bids	$4,587,985	$118,429,678	$71,236,925	$194,254,587
		Sell offers	$8,110,156	$66,098,601	$35,629,669	$109,838,426
	Options	Buy bids	$152,160	$7,375,551	$5,129,655	$12,657,367
		Sell offers	$334,525	$37,003,663	$29,901,741	$67,239,930
	Total		$13,184,826	$228,907,494	$141,897,990	$383,990,310
2014/2015**	Obligations	Buy bids	$1,370,874	$11,646,070	$6,989,461	$20,006,404
		Sell offers	$3,279,375	$7,756,077	$5,507,835	$16,543,287
	Options	Buy bids	$0	$429,965	$404,600	$834,565
		Sell offers	$11,621	$1,391,691	$959,140	$2,362,452
	Total		($1,920,123)	$2,928,267	$927,086	$1,935,231

* Shows Twelve Months; ** Shows one month ended 30-Jun-2014 for 2014/2015

Figure 13-9 summarizes total revenue associated with all FTR sink points, regardless of source, 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 $56.7 million of the total revenue of $10.4 million paid in the auction, they also comprised 4.2 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$21.5 million of revenue and constituted 3.1 percent of all FTRs bought in the auction.

Figure 13-9 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014

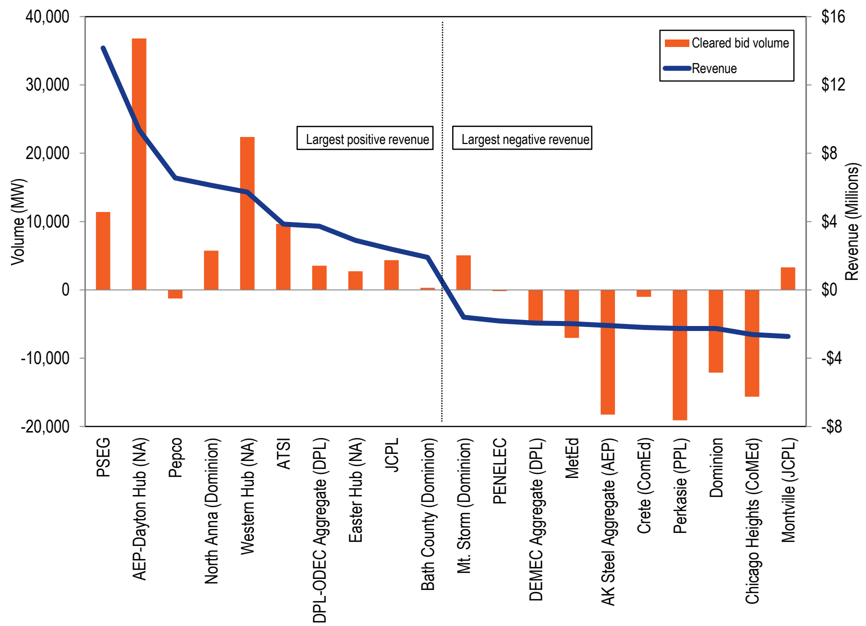
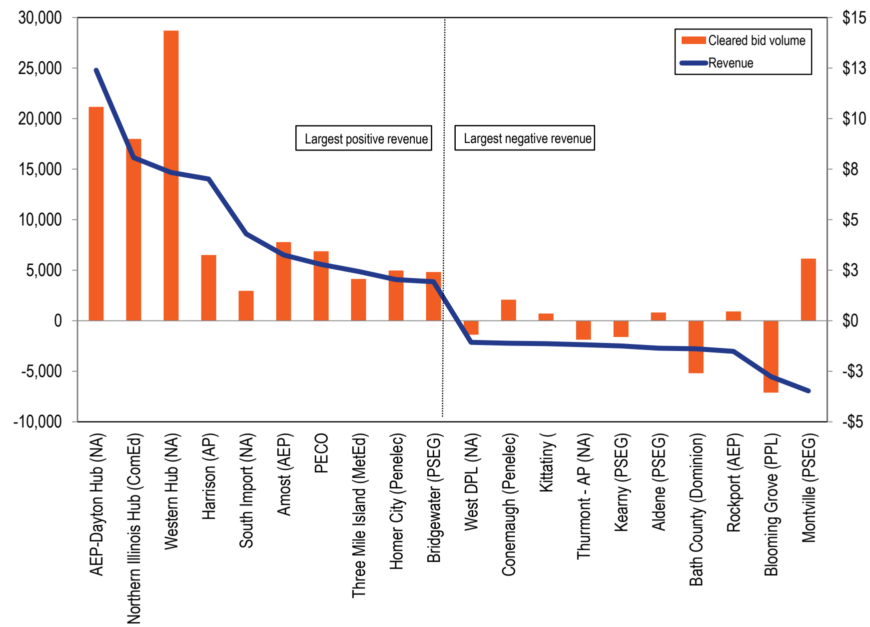


Figure 13-10 summarizes total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period. The top 10 positive revenue producing FTR sources accounted for $51.6 million of the total revenue of $10.4 million paid in the auction, they also comprised 4.7 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$16.2 million of revenue and constituted 0.3 percent of all FTRs bought in the auction.

Figure 13-10 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014



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 2013 to 2014 planning period. Figure 13-11 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2013 to 2014 planning period. The top 10 sinks that produced financial benefit accounted for 14.7 percent of total positive target allocations during the 2013 to 2014 planning period with the Western Hub accounting for 3.6 percent of all positive target allocations. The top 10 sinks that created liability accounted for 8.5 percent of total negative target allocations with the Western Hub accounting for 2.8 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: 2013 to 2014 planning period

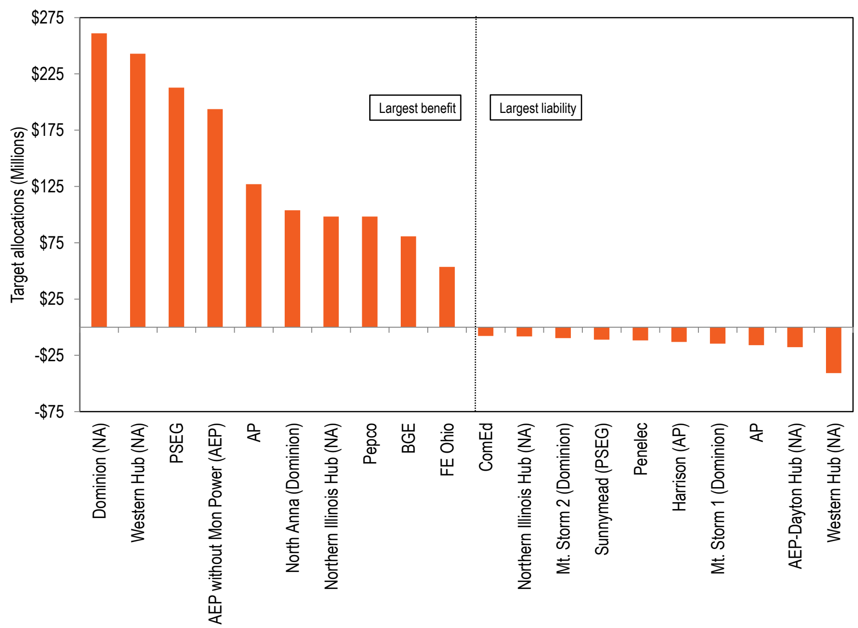
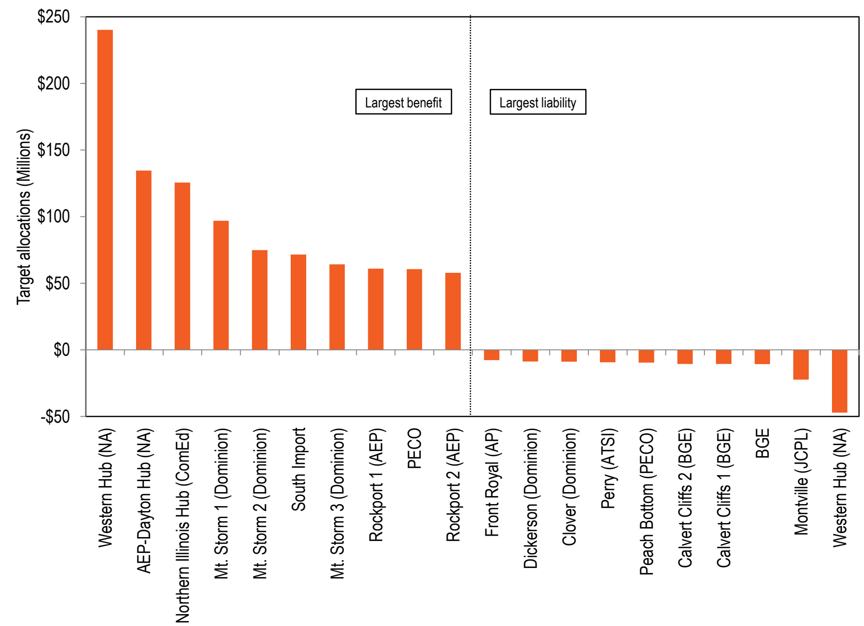


Figure 13-12 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2013 to 2014 planning period. The top 10 sources with a positive target allocation accounted for 22.0 percent of total positive target allocations with Dominion accounting for 3.9 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 8.8 percent of all negative target allocations, with the Western Hub accounting for 2.4 percent.

Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: 2013 to 2014 planning period



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.[10] 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 ARR and FTR revenues to total congestion on the system as a measure of the extent to which ARRs and FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability of ARRs or 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 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. Since the 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected. In June 2014 there was $2.9 million in excess congestion revenue, to be used to fund months later in the planning period that may have a revenue shortfall.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets.[11] 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 13-15 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.[12]

In the first six months of 2014, 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 reciprocally coordinated flowgate (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 redispatch on the designated M2M flowgates, and for the 2013 to 2014 planning period PJM has paid MISO and NYISO a combined $44.3 million. The timing of the addition of new M2M flowgates may reduce FTR funding levels. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any previous PJM FTR

10 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."

11 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

12 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)

auction, may result in oversold FTRs in PJM, and as a direct consequence, reduce FTR funding.

FTRs were paid at 72.8 percent of the target allocation level for the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,819.5 million of FTR revenues during the 2013 to 2014 planning period, and $614.0 million during the 2012 to 2013 planning period, a 196.3 percent increase. Congestion in January 2014 was extremely high due to cold weather events, resulting in target allocations and congestion revenues that were unusually high for 2014. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion and the Western Hub. The top sink with the largest negative FTR target allocation was the Western Hub and the top source with the largest negative FTR target allocation was the Western Hub.

Table 13-15 presents the PJM FTR revenue detail for the 2012 to 2013 planning period and the 2013 to 2014 planning period.

Table 13-15 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	$520.0
FTR auction revenue	$653.6	$593.9
ARR excess	$66.7	$71.7
FTR targets		
Positive target allocations	$992.9	$2,625.8
Negative target allocations	($86.1)	($126.4)
FTR target allocations	$906.8	$2,499.4
Adjustments:		
Adjustments to FTR target allocations	($1.0)	($1.2)
Total FTR targets	$905.8	$2,498.2
FTR revenues		
ARR excess	$66.7	$71.7
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($90.6)	($55.0)
Hourly congestion revenue	$668.4	$1,837.9
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($41.1)	($44.3)
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	$1,810.3
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	$1,819.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$614.0	$1,819.5
Remaining deficiency	$292.3	$678.7

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, the unallocated congestion charges are included in day-ahead operating reserve 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 in three months, 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 13-16 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. Months with no unallocated congestion are excluded from the table.[13]

Table 13-16 Unallocated congestion charges: Planning period 2012 to 2013 and 2013 to 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 13-17 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 13-17 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.

Table 13-17 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2013 to 2014 and 2014 to 2015

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-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)
Jan-14	$815.8	$1,044.0	78.1%	$815.8	78.1%	($228.2)
Feb-14	$167.7	$243.2	68.9%	$167.7	68.9%	($75.5)
Mar-14	$245.5	$367.0	66.8%	$245.5	66.8%	($121.8)
Apr-14	$60.9	$112.2	54.2%	$60.9	54.3%	($51.3)
May-14	$65.2	$113.2	57.6%	$65.2	57.6%	($48.0)
Summary for Planning Period 2013 to 2014						
Total	$1,810.3	$2,498.3		$1,819.5	72.8%	($678.8)
Jun-14	$91.8	$86.1	100.0%	$89.0	100.0%	$5.7
Summary for Planning Period 2014 to 2015						
Total	$91.8	$86.1		$89.0	100.0%	$5.7

Figure 13-13 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through June 2014. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 13-13 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

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

period may change if excess revenue is collected in the remainder of the planning period.

Figure 13-13 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through June 2014

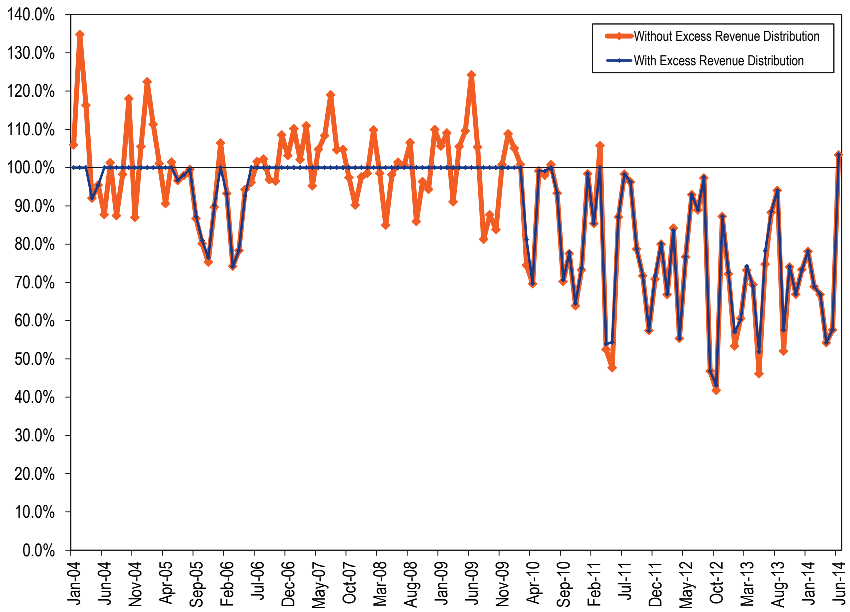


Table 13-18 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For June 2014, there was excess congestion revenue to pay target allocations resulting in a reported payout ratio of 103.3 percent.

Table 13-18 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	72.8%

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 13-19 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.

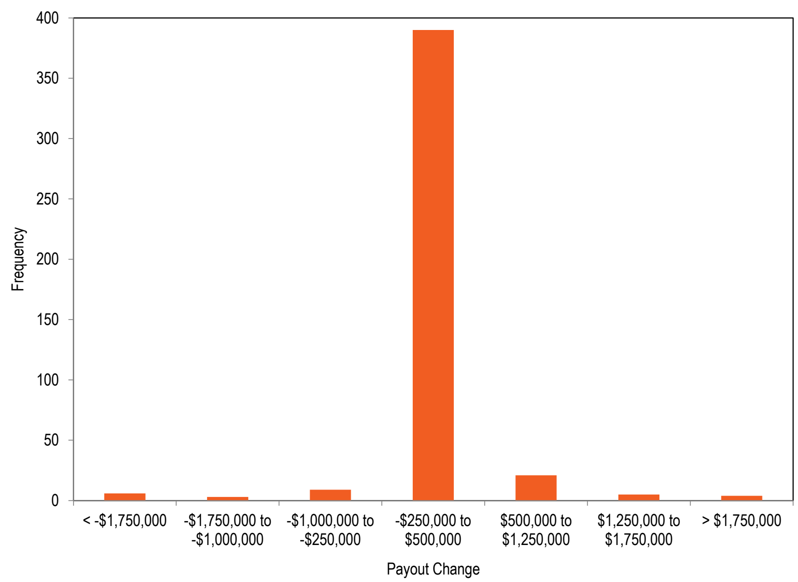
For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every 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 13-19 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		

When the uplift charge is applied at the end of the planning period, a participant may not receive as much from the socialization as they pay in, resulting in a net loss in payments for that participant. Figure 13-14 provides a frequency distribution of this change in payout for participants due to the FTR uplift payments. Many participants receive more than they pay in uplift, but a few participants (30.3 percent) receive less than they pay for uplift, resulting in a decreased payout.

Figure 13-14 Payout change due to end of planning period FTR uplift: Planning period 2013 to 2014



Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown in Table 13-20 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.[14] 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 13-20 shows the PJM reported and actual monthly payout ratios 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 understated payout ratio. In June 2014, there was an excess of FTR revenues, so total funding was actually over 100 percent. Additional revenue will be distributed to future months of the planning period to cover any shortfall.

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

Table 13-20 PJM Reported and Actual Monthly Payout Ratios: Planning period 2013 to 2014

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
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%	74.9%
Jan-14	78.1%	78.9%
Feb-14	69.0%	70.7%
Mar-14	66.8%	68.1%
Apr-14	54.2%	55.3%
May-14	57.6%	62.0%
Jun-14	100.0%	100.0%

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 treats a positive target allocation FTR differently depending on the portfolio of which it is a part. But all FTRs with positive target allocations should be treated in exactly the same way, 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.

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 method 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 13-21 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. In this example, the actual monthly payout ratio is 41.7 percent. If portfolio netting were eliminated, the actual monthly payout ratio would rise to 61.1 percent.

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 13-21 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 13-22 shows the total value for the 2013 to 2014 planning period 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.

Table 13-22 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)
Jun-13	$86,723,727	$(4,836,912)	$164,066,220	$(82,101,063)	$64,060,468	78.3%	79.5%
Jul-13	$134,302,957	$(6,017,378)	$255,724,128	$(127,113,708)	$113,548,567	88.8%	89.3%
Aug-13	$51,545,380	$(5,741,003)	$104,601,365	$(58,796,985)	$43,059,687	94.1%	94.7%
Sep-13	$126,168,822	$(10,172,695)	$279,972,757	$(163,977,565)	$66,719,631	57.5%	61.0%
Oct-13	$69,748,034	$(5,779,197)	$158,354,017	$(94,365,761)	$47,353,545	74.1%	76.2%
Nov-13	$71,460,441	$(4,566,566)	$156,649,135	$(89,755,253)	$44,748,426	66.9%	69.1%
Dec-13	$123,125,598	$(7,182,127)	$256,139,289	$(140,195,812)	$84,974,997	73.3%	74.9%
Jan-14	$1,081,718,330	$(37,626,711)	$2,042,537,214	$(998,445,595)	$815,789,461	78.1%	78.9%
Feb-14	$257,630,277	$(14,286,013)	$581,660,982	$(338,316,718)	$167,731,282	69.0%	70.7%
Mar-14	$381,568,930	$(14,281,323)	$823,861,546	$(456,573,940)	$245,465,062	66.9%	68.2%
Apr-14	$115,047,446	$(2,753,503)	$255,732,814	$(143,428,606)	$60,894,528	54.3%	55.4%
May-14	$126,329,939	$(13,141,697)	$362,871,684	$(249,683,438)	$65,163,098	57.6%	62.0%
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	$2,625,369,880	$(126,385,125)	$5,442,171,151	$(2,942,754,444)	$1,819,508,754	72.8%	87.5%

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.

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 84.5 percent instead of the reported 67.7 percent and the payout ratio for the 2013 to 2014 planning period would have been 87.5 percent instead of 72.8 percent.

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. The payout to the holders of counter flow FTRs is not affected when the payout ratio is less than 100 percent. There is no reason for that asymmetric treatment.

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.

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.

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, parallel to the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide funding between 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.

Table 13-23 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 an actual payout ratio of 87.5 percent. In the example, the profit is shown with and without the counter flow adjustment. As the example shows, the profit of a counter flow FTR does not change when there is a payout ratio less than 100 percent, while the profit of a prevailing flow FTR is reduced. Applying the payout ratio to counter flow FTRs distributes the funding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-23 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 Target Allocation	$35.00	($20.00)
Profit for Positive Target Allocation	($15.00)	$10.00
Payout after Counter Flow Adjustment	$36.67	($21.67)
Profit after Counter Flow Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

Table 13-24 shows the monthly positive, negative and total target allocations.[15] Table 13-24 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 $188.4 million (27.8 percent of difference between revenues and total target allocations) in revenue available to fund positive target allocations for 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 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent.

15 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.

Table 13-24 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
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
Jan-14	$2,042,537,214	($998,445,595)	$1,044,091,619	$815,789,461	78.1%	$1,814,235,056	91.8%	$1,874,258,807
Feb-14	$581,660,982	($338,316,718)	$243,344,264	$167,731,282	68.9%	$506,048,000	90.9%	$528,451,343
Mar-14	$823,861,546	($456,573,940)	$367,287,606	$245,465,062	66.8%	$702,039,002	89.4%	$736,678,623
Apr-14	$255,732,814	($143,428,606)	$112,304,208	$60,894,528	54.2%	$204,323,135	85.6%	$218,931,616
Jun-14	$362,871,684	($249,683,438)	$113,188,246	$65,163,098	57.6%	$314,846,537	90.7%	$329,096,401
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	$5,442,171,151	($2,942,754,444)	$2,499,416,707	$1,819,508,754	72.8%	$4,762,263,198	91.0%	$4,950,708,852

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

Figure 13-15 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through June 2014.

Figure 13-15 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through June 2014

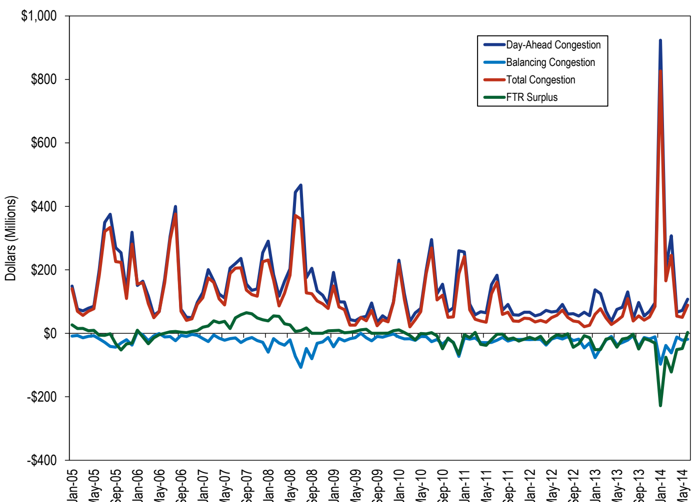
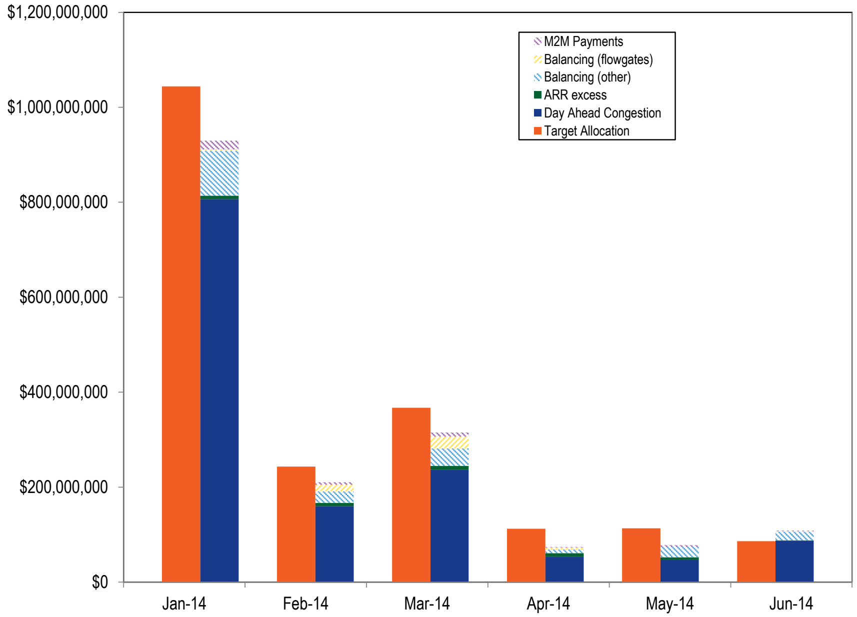


Figure 13-16 shows the relationship among balancing congestion, M2M payments and day-ahead congestion. Only June had enough day ahead congestion to fully pay target allocations. This demonstrates an over selling of FTRs from sources including Stage 1A over allocation and an imperfect FTR or Day Ahead model. In January 2014 cold weather events drove congestion prices, and therefore target allocations, unusually high. In June 2014 day ahead congestion exceeded target allocations and negative revenue sources were small enough resulting in June having an excess of congestion credits and a payout ratio over 100 percent.

Figure 13-16 FTR target allocation compared to sources of positive and negative congestion revenue



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

Incremental ARRs (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.[17] Each

16 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.

17 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>.

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 13-25.

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.[18] Long Term ARRs can give LSEs the ability to offset 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.[19]
- **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.
- **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.[20] Participants may seek additional ARRs in the Stage 2 allocation.

18 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.

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

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

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.[21]

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.[22] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from congestion charges to satisfy all resulting ARR obligations. 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).[23]

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 13-25 shows the top 10 principal binding transmission constraints that limited the 2014 to 2015 Annual ARR Allocation. For the 2014 to 2015 ARR Stage 1A allocation, PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[24]

Table 13-25 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2014 to 2015

Constraint	Type	Control Zone
Waterford - Muskingum	Flowgate	MISO
Breed - Wheatland	Flowgate	MISO
Monroe - Bayshore	Flowgate	MISO
Western Interface	Interface	PJM
Loretto - Wilton Center	Flowgate	MISO
Dickerson - Quince Orchard	Line	Pepco
Cedar Grove - Clifton	Line	PSEG
Nelson - Electric Junction	Flowgate	MISO
Marlton - New Freedom	Line	PSEG
Roseland - Whippany	Line	PSEG

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.[25] 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,

21 *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.

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

23 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.

24 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.

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

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 $499,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 64,086 MW of ARRs associated with approximately $392,100 of revenue that were reassigned for the 2013 to 2014 planning period.

Table 13-26 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2012 and May 2014.

Table 13-26 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2012, through May 31, 2014

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2012/2013 (12 months)	2013/2014 (12 months)*	2012/2013 (12 months)	2013/2014 (12 months)*
AECO	581	971	$3.0	$3.8
AEP	4,656	8,006	$58.9	$25.6
AP	3,518	2,618	$84.3	$51.4
ATSI	5,314	6,792	$8.3	$8.9
BGE	3,203	3,672	$37.3	$42.2
ComEd	11,824	9,664	$170.9	$104.9
DAY	589	1,100	$0.9	$2.1
DEOK	2,979	7,568	$1.6	$9.8
DLCO	2,708	5,248	$19.1	$11.5
Dominion	0	5	$0.0	$0.1
DPL	1,989	2,740	$11.5	$25.0
EKPC	NA	0	NA	$0.0
JCPL	1,373	1,519	$5.6	$5.7
Met-Ed	1,107	1,043	$8.6	$7.6
PECO	3,416	2,883	$22.8	$21.8
PENELEC	920	1,265	$8.3	$11.8
Pepco	3,073	3,134	$21.4	$11.8
PPL	3,197	3,197	$20.7	$13.3
PSEG	2,313	2,441	$16.6	$24.6
RECO	67	221	$0.0	$0.1
Total	52,825	64,086	$499.8	$382.1

* Through 31-May-2014

Incremental ARRs (IARRs) for RTEP Upgrades

Figure 13-17 lists the incremental ARR allocation volume for the current and previous planning periods from the 2008 to 2009 planning period through the 2014 to 2015 planning period.

Table 13-27 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2014 to 2015

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%
2014/2015	18	1,447.4	1,447.4	100%	0	0%

Table 13-27 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs.

Table 13-28 IARRs allocated for 2014 to 2015 Annual ARR Allocation for RTEP upgrades

		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 13-28 shows the residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 13-29 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
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	3,896.0	1,751.1	44.9%	$332,495
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
Jan-14	2,809.3	1,760.3	62.7%	$273,006
Feb-14	2,076.9	1,564.0	75.3%	$480,688
Mar-14	11,733.8	1,203.1	10.3%	$1,030,177
Apr-14	4,156.2	2,723.5	65.5%	$284,042
May-14	1,542.7	389.6	25.3%	$333,749
Total	62,665.5	15,417.5	24.6%	$4,683,134

Market Performance

Volume

Table 13-29 shows the volume of ARR allocations for each round of the 2013 to 2014 and 2014 to 2015 planning periods.

Table 13-30 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
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%
2014/2015	1A	0	19,287	68,843	68,838	100.0%	5	0.0%
	1B	1	14,235	35,104	2,390	6.8%	32,714	93.2%
	2	2	5,517	27,708	361	1.3%	27,347	98.7%
		3	5,817	27,914	456	1.6%	27,458	98.4%
		4	5,381	27,953	291	1.0%	27,662	99.0%
		Total	16,715	83,575	1,108	1.3%	82,467	98.7%
	Total		50,237	187,522	72,336	38.6%	115,186	61.4%

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, 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 2014 to 2015 planning period, Stage 1A of the Annual ARR Allocation was infeasible and additional capability was added to the ARR allocation as well as the FTR auction. 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 these increased limits must 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.[26]

The result 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 funding problem by permitting the sale of more FTRs than are physically feasible with no increase in congestion collected.

Table 13-30 lists the constraints for which ARR requests were found to be infeasible for the 2014 to 2015 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.

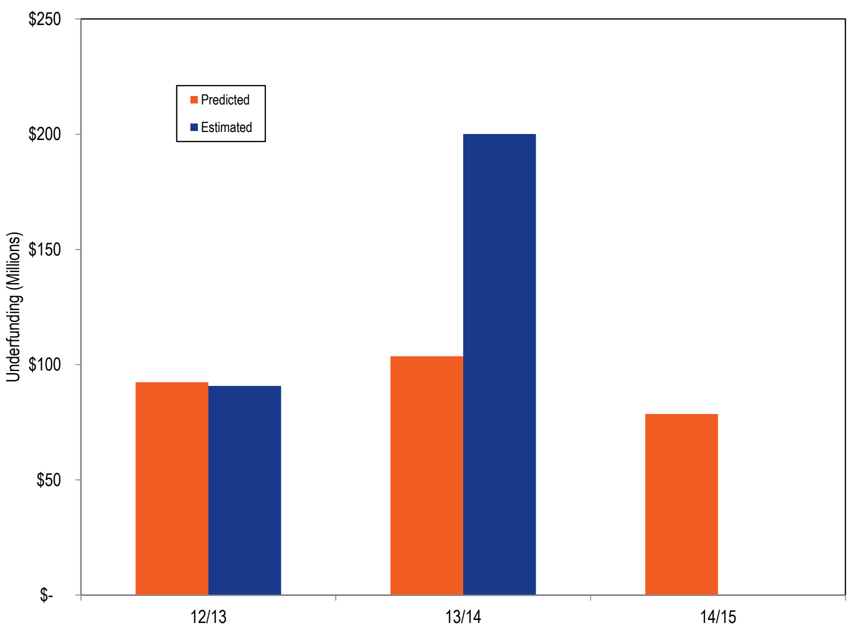
26 The FTR Senior Task Force is discussing the Stage 1A Infeasibility requirement.

Table 13-31 Constraints with capacity increases due to Stage 1A infeasibility for the 2014 to 2015 ARR Allocation

Constraint	Contingency	Type	Zone	MW Increase	Reason
Breed - Wheatland	Rockport-Jefferson	Flowgate	MISO	329	Load
Loretto - Wilton Center	Pontiac-Dresden	Flowgate	MISO	230	Load
Nelson - Electric Junction	Cherry Valley-Silver Lake	Flowgate	MISO	204	Load
Marengo Tap - Pleasant Valley	Cherry Valley-Silver Lake	Flowgate	MISO	159	Load
Babcock - Stillwell	Wilton Center-Dumont	Flowgate	MISO	148	Load
Pleasant Prairie - Zion	Pleasant Prairie-Zion	Flowgate	MISO	121	Load
Cordova - Nelson	Nelson	Flowgate	MISO	120	Load
Byron - Cherry Valley	Byron - Cherry Valley	Line	ComEd	83	Outages
Woodstock	Cherry Valley-Silver Lake	Flowgate	MISO	75	Load
Oakgrove - Galesburg	Nelson-Electric Junction	Flowgate	MISO	69	Load
Galesburg	Electric Junction-Nelson	Flowgate	MISO	68	Load
Nelson	Nelson-Electric Junction	Flowgate	MISO	61	Load
Butler - Karns City	BASE	Line	AP	59	Outages
Burr Oak - Plymouth	Burr Oak-Lessburg	Flowgate	MISO	56	Load
Oakgrove - Galesburg	Cordova-Nelson	Flowgate	MISO	56	Load
Athenia - Bellville	BASE	Line	PSEG	55	Outages
East Akron - Knox	BASE	Line	ATSI	52	Outages
Belvidere	Cherry Valley-Silver Lake	Flowgate	MISO	52	Load
Oakgrove - Galesburg	Sterling-Nelson	Flowgate	MISO	52	Load
Kewanee - Edwards	Duck Creek-Tazewell	Flowgate	MISO	44	Load
Kewanee - Edwards	Nelson-Electric Junction	Flowgate	MISO	38	Load
Paddock - Townline	Paddock-Blackhawk	Flowgate	MISO	33	Load
Cedar Grove - Clifton	Cedar Grove-Clifton-Athenia	Line	PSEG	32	Load
Bremo - Buckingham	Carson-Clover	Line	Dominion	31	Outages
Athenia - Clifton	Cedar Grove-Clifton-Athenia	Line	PSEG	31	Load
Butler - Karns City	Handsome Lake-Homer City	Line	AP	30	Outages
Church - Townsend	Cedar Creek-Red Lion	Line	DPL	25	Outages
Babb - Evans	Hanna-Juniper	Line	ATSI	22	Outages
Monticello-East Winamac	Schahfer-Burr Oak	Flowgate	MISO	21	Load
Athenia - Bellville	Hillsdale-Waldwick	Line	PSEG	19	Outages
Beaver Channel - Albany	Rock Creek-Salem	Flowgate	MISO	19	Load
Belleville - Penhorn Tap	Hillsdale-Waldwick	Line	PSEG	18	Outages
Mazon - La Salle	Braidwood - E. Frankfort	Line	ComEd	16	Outages
Mazon - Dresden	Braidwood - E. Frankfort	Line	ComEd	15	Outages
Church - New Meredith	Cedar Creek-Red Lion	Line	DPL	14	Outages
Lakeview	Carson-Clover	Transformer	ATSI	14	Outages
East Akron - Knox	Sammis-Star	Line	ATSI	12	Outages
Athenia - East Rutherford	Hudson-Penhorn-Belville	Line	PSEG	11	Outages
Kammer	Muskingham River-Kammer	Transformer	AEP	10	Outages
Rantoul - Rantoul Junction	N. Champaign-Mahomet-Rising	Flowgate	MISO	10	Load
Otter - Alta Vista	Cloverdale	Line	Dominion	8	Outages
Middletown Junction	Middletown Junction #5	Transformer	MetEd	7	Outages
Dixon - Stillman Valley	Nelson - Electric Junction	Line	ComEd	7	Load
Babb - Evans	BASE	Line	ATSI	6	Outages
Michigan City - Laporte	Wilton Center	Flowgate	MISO	6	Load
Alta Vista	Altavista	Transformer	Dominion	4	Outages
Mazon	Pontiac-Brokaw	Flowgate	MISO	3	Outages
Hudson - Penhorn	BASE	Line	PSEG	2	Outages

Figure 13-17 shows the predicted and estimated impact of Stage 1A infeasibilities on funding for the 2012 to 2013 and 2013 to 2014 planning period, as well as the predicted impact on funding for the 2014 to 2015 planning period. The predicted funding is based on the infeasible ARR MW and the nodal price of the source and sink in the Annual FTR Auction. The estimated funding is calculated assuming every infeasible ARR MW self scheduled, and uses the hourly congestion LMP values. In the 2013 to 2014 planning period Stage 1A, ARR infeasibilities accounted for $200.1 million in over allocation. Elimination of these infeasibilities would raise the payout ratio from 72.8 percent to 80.8 percent. Elimination of portfolio netting, the counter flow FTR subsidy and Stage 1A ARR over allocation would increase the payout ratio to 94.6 percent.

Figure 13-17 Stage 1A Infeasibility Funding Impact



Revenue

ARRs are allocated to qualifying customers rather than sold, so 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 $568.8 million in credits from the FTR auctions during the 2013 to 2014 planning period. During the 2013 to 2014 planning period, ARR holders received $506.2 million in ARR credits.

Table 13-31 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 2013 to 2014 planning periods.

Table 13-32 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

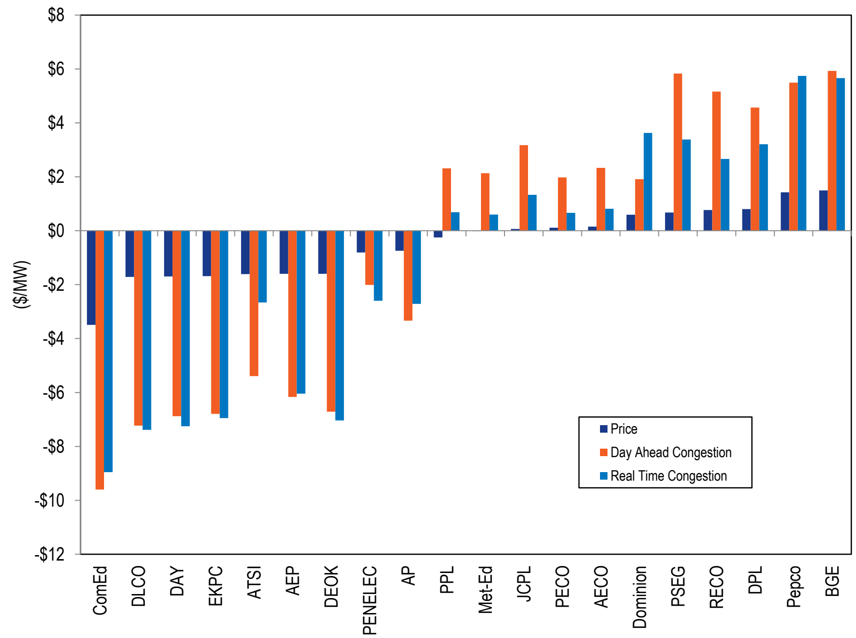
	2012/2013	2013/2014
Total FTR auction net revenue	$626.7	$568.8
Annual FTR Auction net revenue	$602.9	$558.4
Monthly Balance of Planning Period FTR Auction net revenue	$23.9	$10.4
ARR target allocations	$570.5	$506.2
ARR credits	$570.5	$506.2
Surplus auction revenue	$56.2	$62.6
ARR payout ratio	100%	100%
FTR payout ratio	67.8%	72.8%

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 13-18 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for 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 13-18 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



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 2013 to 2014 planning period, the total revenues received by the holders of all ARRs and FTRs offset 98.2 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 13-32. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[27] 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 72.8 percent of the target allocation for 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 congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for 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.

27 For Table 13-32 through Table 13-34, 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.

Table 13-33 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period[28]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$4.1	$0.0	$4.1	$14.0	($9.9)	29.1%
AEP	$32.4	$144.5	$176.9	($15.8)	$246.7	>100%
APS	$42.0	$57.8	$99.9	($18.9)	$140.4	>100%
ATSI	$5.8	$0.3	$6.1	($8.2)	$14.4	>100%
BGE	$29.3	$3.0	$32.4	$30.1	$3.4	>100%
ComEd	$74.6	$0.0	$74.6	$22.7	$51.9	>100%
DAY	$4.0	$0.0	$4.0	($6.2)	$10.2	>100%
DEOK	$3.7	$1.7	$5.4	($12.9)	$18.9	>100%
DLCO	$1.9	($0.2)	$1.6	($4.3)	$5.8	>100%
Dominion	$7.7	$170.8	$178.5	$14.9	$227.4	>100%
DPL	$17.2	$4.1	$21.3	$36.0	($13.3)	59.0%
EKPC	$0.6	$0.2	$0.9	($6.2)	$7.2	>100%
External	$2.2	$1.2	$3.5	$10.5	($6.5)	33.3%
JCPL	$6.7	$0.1	$6.7	$32.1	($25.4)	21.0%
Met-Ed	$6.8	$0.3	$7.0	$14.2	($7.1)	49.6%
PECO	$22.3	$0.2	$22.5	($13.9)	$36.6	>100%
PENELEC	$12.1	($1.1)	$11.0	$11.2	($0.6)	98.5%
Pepco	$16.4	$8.6	$25.0	$48.5	($20.3)	51.5%
PPL	$11.0	$0.5	$11.5	$58.3	($46.6)	19.8%
PSEG	$38.2	$10.0	$48.2	$16.6	$35.3	>100%
RECO	$0.1	$0.0	$0.1	$2.0	($1.9)	5.2%
Total	$339.0	$413.7	$752.7	$224.7	$682.3	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-33 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 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

28 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.

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 72.8 percent of the target allocation for 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.[29] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

Table 13-34 ARR and FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset – Congestion Difference	Percent Offset
AECO	$4.1	$10.7	$5.6	$9.2	$27.0	($17.7)	34.2%
AEP	$83.5	$272.1	$104.0	$251.5	$424.2	($172.7)	59.3%
APS	$66.3	$106.0	$35.8	$136.5	$201.7	($65.2)	67.7%
ATSI	$5.9	$87.6	$2.3	$91.2	($35.9)	$127.1	>100%
BGE	$30.5	$99.5	$35.6	$94.4	$124.1	($29.8)	76.0%
ComEd	$84.2	$115.3	$53.0	$146.5	$326.1	($179.6)	44.9%
DAY	$4.0	$12.6	$4.0	$12.7	($2.1)	$14.7	>100%
DEOK	$4.4	$12.7	$4.3	$12.7	($27.4)	$40.1	>100%
DLCO	$2.1	($7.2)	$0.4	($5.5)	($10.7)	$5.2	0.0%
Dominion	$94.9	$297.4	$134.3	$257.9	$191.5	$66.4	>100%
DPL	$19.4	$69.6	$17.0	$71.9	$101.6	($29.7)	70.8%
EKPC	$2.1	$3.4	$3.0	$2.4	($13.1)	$15.6	>100%
External	$2.8	$25.4	$0.7	$27.5	$72.1	($44.7)	38.1%
JCPL	$6.7	$74.9	$6.2	$75.4	$97.4	($22.0)	77.4%
MetEd	$6.9	$28.3	$5.5	$29.7	($9.7)	$39.4	>100%
PECO	$22.4	$20.7	$18.5	$24.6	($37.4)	$62.0	>100%
PENELEC	$11.9	$108.8	$40.5	$80.2	$119.0	($38.7)	67.4%
Pepco	$19.7	$187.3	$76.3	$130.6	$140.0	($9.3)	93.3%
PPL	$11.1	$35.2	($2.2)	$48.5	($6.1)	$54.7	>100%
PSEG	$39.4	$253.6	$55.5	$237.6	$77.0	$160.6	>100%
RECO	$0.1	($1.2)	($1.5)	$0.3	$11.8	($11.5)	2.6%
Total	$522.3	$1,814.9	$598.8	$1,738.3	$1,771.0	($32.7)	98.2%

Table 13-34 shows the total offset due to ARRs and FTRs for the entire 2012 to 2013 and the 2013 to 2014 planning periods. ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 98.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for 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.

29 The total zonal congestion numbers were calculated as of July 25, 2014 and may change as a result of continued PJM billing updates.

Table 13-35 ARR and FTR congestion hedging (in millions): Planning periods 2012 to 2013 and 2013 to 2014[30]

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*	$522.3	$1,814.9	$598.8	$1,738.3	$1,771.0	($32.7)	98.2%

* Shows full planning period

30 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.