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, the delivery of low cost generation to load was based both on zonal generation and zonal transmission under cost of service rates, and on contracts with specific remote generation outside the local zone and on associated point to point transmission contracts. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through cost of service rates or through bilateral contracts received the low cost generation.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the day-ahead and balancing markets, to permit the loads which pay for the transmission system to continue to receive the benefits of access to either local or remote low cost generation in the form of FTR revenues which offset congestion.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load pays more for low cost generation than is paid to low cost generation. Under LMP, load pays and generation is paid locational prices which result in load payments in excess of generation revenues. The excess payments are congestion. The origin of FTRs was the recognition that the way to hold load harmless from making these excess payments created by the LMP system was to return the excess payments to load through the mechanism of FTRs. The rights to congestion belong to load.

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

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, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] 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 ensure that all congestion revenues are returned to load.

Effective April 1, 1999, FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing congestion to load. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR construct, the load still owns the rights to congestion revenue, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR construct, all FTR auction revenues should belong to the load and all of the congestion revenues should belong to those that purchase or self schedule the FTRs.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues, and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[3] For the 2017/2018 planning

2 See *id.* at 62,259–62,260 & n. 123.

3 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180.

period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion.

On May 31, 2018, a rule change was implemented to offset the more egregious effects of the allocation of balancing congestion to load.[4] Effective for the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue were allocated to ARR holders.[5]

Surplus congestion revenue should be allocated to ARR holders because surplus day-ahead congestion and surplus auction revenue are associated with unallocated ARR capacity. This residual capacity is unallocated as a result of PJM's conservative modeling designed to improve FTR funding. Had this surplus allocation been implemented in the 2017/2018 planning period, the percent of congestion offset by ARRs and FTRs would have increased from 50.0 percent to 74.3 percent. For the 2018/2019 planning period, 92.1 percent of congestion was offset.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the failure to assign all FTR auction revenues to ARR holders, differences between modeled and actual system capability and numerous cross subsidies among participants. One of the key flaws in the original design was the link between congestion revenues and specific generation to load transmission paths. This link retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design would have been avoided. The design should simply have provided for the return of all congestion revenues to load. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

To address the issues with the current path based ARR/FTR market construct, the Market Monitor is proposing that the current construct be replaced with a network construct in which the rights to actual congestion are assigned directly to load by node. The allocated right is to the actual congestion collected, both day-ahead and balancing, between the load at a bus and the generation used to serve that load. The load can retain the right to the network congestion or sell the right through auctions with the desired frequency.

The network allocation of actual congestion has a number of advantages over the current path based approach. There are no cross subsidies among rights holder and no over or under allocation of rights relative to actual network market solutions. There are no revenue shortfalls as congestion payments equal congestion collected. There is no risk of prevailing flow FTRs flipping in value because congestion is always positive or zero and the full amount of congestion is always allocated. The risk of default is isolated to the buyer and seller of the right, and any default is not socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues revert to the load.

The *2019 Quarterly State of the Market Report for PJM: January through June* focuses on the 2019/2022 Long Term FTR Auction, the 2019/2020 Annual FTR Auction and the 2018/2019 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2019, through June 30, 2019. A caveat that applies to the 2018/2019 planning period is that the results may change depending on the final FERC actions in the GreenHat Energy, LLC matter.[6]

4 On May 31, 2018, FERC issued an order accepting PJM's proposal to allocate surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165.

5 163 FERC ¶61,165 (2018).

6 See 166 FERC ¶ 61,072, *reh'g pending*; see also 163 FERC ¶ 61,157 (establishing settlement judge proceedings).

Table 13-1 The FTR auction markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Partially Competitive	
Participant Behavior	Partially Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as partially competitive because while purchasing FTRs in the FTR Auction is voluntary, issues have been identified with the under assignment of system capability to ARRs and the accuracy of modeling in the Long Term FTR Auctions.
- Participant behavior was evaluated as partially competitive based on the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and the expected system capability that PJM made available for sale as FTRs. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs also raises questions about the market structure, the market performance and the market design.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient or effective way to ensure that all congestion revenues are returned to load. ARR holders' rights to congestion revenues are not defined clearly enough. The path based assignment of congestion rights is inadequate and incorrect. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue.

Overview

Auction Revenue Rights

Market Structure

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the 2018/2019 planning period, PJM allocated a total of 27,335.6 MW of residual ARRs, down from 39,597.4 MW in the 2017/2018 planning period, with a total target allocation of $11.8 million for the 2018/2019 planning period, down from $17.5 million for the 2017/2018 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned in the 2018/2019 planning period. There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned for the 2017/2018 planning period.

Market Performance

- **Revenue Adequacy.** For the 2018/2019 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $726.8 million, while PJM collected $907.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The new allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues at the end of the planning period are allocated to ARR holders. For the 2017/2018 planning period, the ARR target allocations were $573.8 million while PJM collected $601.2 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, under the previous allocation of balancing congestion. In the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 50.0 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, ARRs, self scheduled FTRs and surplus congestion revenue offset 92.1 percent of total congestion costs. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

Financial Transmission Rights

Market Structure

- **Supply.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the 2019/2022 Long Term FTR Auction, total participant FTR sell offers were 318,022 MW. In the 2019/2020 Annual FTR Auction, total participant FTR sell offers were 375,582 MW. In the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period, total participant FTR sell offers were 8,483,263 MW, up from 4,401,873 MW for the same period during the 2017/2018 planning period.
- **Demand.** In the 2019/2022 Long Term FTR auction, total FTR buy bids were 1,949,546 MW, down 5.0 percent from 2,052,820 MW the previous long term auction. There were 2,816,861 MW of buy and self scheduled bids in the 2019/2020 Annual FTR Auction, down 3.1 percent from 2,907,583 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period increased 3.6 percent from 19,138,752 MW for the same time period of the prior planning period, to 19,827,194 MW.
- **Patterns of Ownership.** For the 2019/2022 Long Term FTR Auction, financial entities purchased 68.1 percent of prevailing flow FTRs and 70.4 percent of counter flow FTRs. For the 2019/2020 Annual FTR Auction, financial participants purchased 64.8 percent of all prevailing flow FTRs and 79.5 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 72.3 percent of prevailing flow and 81.5 percent of counter flow FTRs for January through June of 2019. Financial entities owned 71.2 percent of all prevailing and counter flow FTRs, including 63.9 percent of all prevailing flow FTRs and 81.7 percent of all counter flow FTRs during the period from January through June 2019.

Market Behavior

- **FTR Forfeitures.** For the period January 19, 2017, through June 30, 2019, total FTR forfeitures were $14.5 million.
- **Credit.** There were no collateral defaults in the first six months of 2019. There were 58 payment defaults in 2019 not involving GreenHat Energy, LLC for a total of $59,933. GreenHat Energy continued to accrue payment defaults of $39.1 million in the first six months of 2019, for a total of $116.1 million in defaults for the company, including the auction liquidation costs.

Market Performance

- **Volume.** The 2019/2022 Long Term FTR Auction cleared 408,237 MW (20.9 percent) of FTR buy bids, up 18.2 percent from 345,506 MW (16.8 percent) in the 2018/2021 Long Term FTR Auction. The Long Term FTR Auction also cleared 35,412 MW (11.1 percent) of FTR sell offers, compared to 42,555 (17.8 percent), a 16.9 percent decrease.

- In the Annual FTR Auction for the 2019/2020 planning period 641,023 MW (22.8 percent) of buy and self schedule bids cleared, up 4.2 percent from 615,254 MW (21.2 percent) for the previous planning period. In the 2018/2019 planning period Monthly Balance of Planning Period FTR Auctions cleared 3,157,852 MW (15.9 percent) of FTR buy bids and 1,703,548 MW (20.1 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2019/2020 Long Term FTR Auction was $0.10 per MW, up from $0.03 per MW for the 2018/2021 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2019/2020 planning period was $0.66 per MW, up from $0.59 per MW in the 2018/2019 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period was $0.20, up from $0.13 per MW for the same period in the 2017/2018 planning period.
- **Revenue.** The 2019/2022 Long Term FTR Auction generated $161.7 million of net revenue for all FTRs, up from $29.6 million for the 2018/2021 Long Term FTR Auction. The 2018/2019 Annual FTR Auction generated $822.6 million in net revenue, up from $542.2 million for the 2017/2018 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $59.7 million in net revenue for all FTRs of the 2018/2019 planning period, up from $40.3 million for the same time period in the 2017/2018 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2018/2019 planning period. This level of FTR funding was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the 2018/2019 planning period, physical entities made -$52.3 million in profits on FTRs purchased directly (not self scheduled), while receiving $129.9 million in returned congestion from self scheduled FTRs, and financial entities made $116.5 million in profits.

Markets Timeline

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

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2020/2023 Long Term	6/3/2019	12/11/2019
2018/2019 ARR	3/4/2019	4/5/2019
2018/2019 Annual	4/9/2019	5/6/2019

Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[7] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM 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. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Pending at FERC.)
- The MMU recommends that the direct customer request approach for creating and allocating IARRs should be eliminated from PJM's tariff. (Priority: Low. First reported 2018. Status: Not adopted.)

Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service, which results in the delivery of low cost generation, which results in load paying congestion revenues, in an LMP market.

Revenue adequacy is misunderstood and generally incorrectly defined. Revenue adequacy has received a lot of attention in the PJM FTR Market and conclusions based on the incorrect definition have led to significant changes in the design of the ARR/FTR market that have distorted the function and purpose of ARRs and FTRs as a means of allocating congestion and congestion

7 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

rights. Correctly defined, revenue adequacy for ARRs means that ARRs have the rights to 100 percent of congestion revenue. FTR holders, with the creation of ARRs, do not have a right to receive revenues equal to CLMP differentials on individual FTR paths.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 planning years. With surplus through May 2019 distributed, total ARR and self scheduled FTR revenue offset 92.1 percent of total congestion costs for the 2018/2019 planning period.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[8] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[9] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR holders. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. This approach ignores the fact that loads must pay both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. Based on a recent rule change, balancing congestion is allocated to load on a load ratio share, rather than on the basis of location or source of the balancing congestion. This rule creates inappropriate cross subsidies among loads.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Load will continue to be the source of all the funding for FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. Under the current FTR design, FTR holders should receive actual congestion on the relevant FTR paths and paths should be limited to actual physical source and sink points to align congestion rights with the paths that generate congestion and to limit cross subsidies. But PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current design.

8 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
9 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with market conditions. If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,160.0 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2017/2018 planning period would have been $1,315.1 million.

The actual underpayment to load and the overpayment to FTR holders was a result of several rules, all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is not assigned rights to all congestion as a result of using generation to load paths. Load is required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders while degrading the ability of ARRs to provide a predictable offset to congestion costs. Surplus revenues from the FTR auction are not assigned to ARR holders, but are used by PJM to clear counter flow FTRs in the Monthly FTR Auctions in order to make it possible to sell more prevailing flow FTRs and to insure revenue adequacy for FTRs before distribution to ARR holders. Under the prior rules, surplus revenues in the day-ahead market were assigned directly to FTR holders along with surplus auction revenues.

A rule change was implemented by PJM that offset the more egregious effects of the allocation of balancing congestion to load. Beginning with the 2018/2019 planning period, surplus revenues in the day-ahead market and surplus auction revenue are assigned to FTR holders only up to revenue adequacy, and then distributed to ARR holders. This is consistent with a recognition that PJM's modeling does not assign the full capacity of the system to ARR holders.[10]

All congestion revenue belongs to ARR holders, and PJM's new surplus congestion allocation rule is consistent with that goal. However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules do not fully recognize ARR holders' primary rights to surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 percent.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, Stage 1A ARR overallocation is a source of reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because many of the over allocations are due to outages in the FTR model, or are not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

In addition to addressing these issues, the approach to the question of FTR funding should also examine the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation 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

10 163 FERC ¶61,165 (2018).

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.

It is not clear, in a competitive market, why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the MMU recommends that Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. This would ensure ARR holders' rights to congestion while maintaining the ability for participants to purchase congestion offsets for future planning periods.

Auction Revenue Rights

ARR revenues result from the sale of congestion rights that belong to ARR holders. ARRs are the financial instruments through which the proceeds from FTR Auctions are allocated to load. ARR values are based on nodal price differences, established by cleared FTR bids in the Annual FTR Auction, between the ARR source and sink points in the FTR Auction.[11] ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available system capability. PJM has significant discretion over that level of system capability. The appropriate goals of that discretion need to be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 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's value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source, and represents the fixed stream of revenue that an ARR holder would receive if the ARR is retained. 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, otherwise, available revenue is proportionally allocated among all ARR holders. If there are auction revenues greater than the ARR target allocations, the revenue is first used to fully fund ARRs in previous months, then fully fund FTRs, and then provided to ARR holders at the end of the planning period.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all the congestion revenues, and has the ability to receive the auction revenues associated with all the potential congestion revenues whether through self scheduling or selling the rights to FTR holders. If ARR holders have rights to all congestion revenue and the FTR auction is the way in which ARR holders exchange rights to congestion for fixed payments, then 100 percent of the FTR auction revenue should be assigned to ARR holders. The MMU recommends that all FTR auction revenues be allocated to 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,

11 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.

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

On December 1, 2018, PJM integrated the Ohio Valley Electric Cooperative (OVEC) as a PJM zone. In anticipation of OVEC joining PJM earlier, PJM included the OVEC Zone integration into their 2018/2019 Annual ARR Allocation, so that Kyger Creek and Clifty Creek were valid source points, and the OVEC residual aggregate was added as a biddable node in the ARR model. From June 1, 2018, to December 1, 2018, any ARRs or self scheduled FTRs source at Kyger Creek and Clifty Creek resources were remapped back to the historical OVEC Interface. Effective December 1, 2018, any ARRs and self scheduled FTRs which were allocated in the Annual ARR Allocation to the OVEC interface were remapped back to Clifty Creek or Kyger Creek.

Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to generate IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[12]

There are three approaches to the creation and assigning of IARRs: IARRs can be requested by customers, which requires the customer to build sufficient transmission to support the request; IARRs can be the granted as a result of customer transmission projects such as merchant transmission or generation interconnection projects; and IARRs can be the result of RTEP upgrades. In each case, the customer(s) paying for the upgrades are allocated the IARR that are created.

The direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. Given the current allocation of existing ARRs relative to system capability, the upgrades needed to produce any quantity of IARR under this approach are prohibitively expensive and impractical. The PJM process is not sufficiently transparent for a potential customer to make a rational decision about a potential IARR project. Much of the information required to determine whether a particular IARR project is economically viable is confidential and proprietary to incumbent transmission companies including the nature and cost of any required upgrades.

IARRs are appropriately 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.[13] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 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 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Supply and Demand

System capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model.

12 See "PJM Incremental Auction Revenue Rights Model Development and Analysis," P(June 12, 2017) <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.

13 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019); "IARRs for RTEP Upgrades Allocated for 2016/2017 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2018-2019/2018-2019-iarrs-for-rtep-upgrades-allocated.ashx>.

PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

ARR Allocation

For the 2007/2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[14] Stage 1A ARRs can give LSEs the ability to offset their congestion costs, through the return of congestion revenues, on a long-term basis. Stage 1B and Stage 2 ARRs provide a method for ARR holders to have additional congestion revenues returned to them in the planning period over their Stage 1A allocation, but may be prorated. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[15]

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

- Stage 1A. In the first stage of the allocation, network transmission service customers can obtain ARRs, up to their share of Zonal Base Load, which is the lowest daily peak load in the prior twelve month period increased by load growth projections. The amount of Stage 1A ARRs a participant can request is based on generation to load paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired, in the historical reference year for the zone. The historical reference year is the year prior to the creation of PJM markets, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of 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.[16]
- Stage 1B. Transmission capacity unallocated in Stage 1A is available in the Stage 1B allocation for the planning period. Network transmission service customers can obtain ARRs up to their share of zonal peak load, which is the highest daily peak load in the prior twelve month period increased by load growth projections, based on generation to load paths and up to the difference between their share of zonal peak load and Stage 1A allocations. 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.
- Stage 2. Stage 2 of the annual ARR allocation allocates the remaining system capability equally in three steps. 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 up to their total peak network load in that zone. 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.[17] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015/2016 planning period, when residual zone pricing was introduced, an ARR will default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[18]

14 See *2006 State of the Market Report for PJM* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.
15 OATT Attachment K 7.1.1.(b).
16 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).
17 *Id.* at 21.
18 *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>.

ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12 month planning period.

When ARRs are allocated after Stage 1A, all ARRs must be simultaneously feasible, meaning that the modeled transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM uses a power flow model of security constrained dispatch based on assumptions about generation and transmission outages.[19] 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, except Stage 1A ARRs:

Equation 13-1 Calculation of prorated ARRs[20]

$$MW = Constraint\ Capability\ x \left(\frac{Individual\ Requested\ MW}{Total\ Requested\ MW}\right) x \left(\frac{1}{MW\ impact\ on\ line}\right)$$

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 ARR MW that would have a power flow on the binding constraint. The PJM method prorates ARR requests in proportion to their MW value and the impact on the binding constraint. The PJM method prorates only ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their impact on the binding constraints, the result would reduce allocated ARRs below actually available ARRs.

FERC Order EL16-121: Stage 1A ARR Allocation

FERC ordered PJM to remove retired resources from the generation to load paths used to allocate Stage 1A ARRs.[21] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[22]

The method PJM implemented continues to rely on a contract path based approach. Existing Stage 1A resources will be given their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources will be prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, the new ARRs will have lower priority than the preexisting Stage 1A resources, which could affect the value of the newly assigned ARRs. Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load paths should not be used as a basis for assigning ARR capability. Contract paths are not an accurate representation of the reasons that congestion is created or that load is served in a network and will, by definition, not accurately measure the exposure of load to congestion, resulting in modeling inaccuracies and revenue inadequacy.

Market Performance

Volume

Table 13-3 shows the MW of ARR allocations for each round of the 2018/2019 and 2019/2020 planning periods.

Table 13-3 Annual ARR Allocation volume: 2018/2019 and 2019/2020

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2018/2019	1A	0	30,813	77,407	76,250	98.5%	1,157	1.5%
	1B	1	17,496	37,203	20,054	53.9%	17,149	46.1%
	2	2	6,553	20,327	1,892	9.3%	18,435	90.7%
		3	5,039	19,420	3,314	17.1%	16,106	82.9%
		4	5,405	19,731	3,716	18.8%	16,015	81.2%
		Total	16,997	59,478	8,922	15.0%	50,556	85.0%
	Total		65,306	174,088	105,226	60.4%	68,862	39.6%
2019/2020	1A	0	30,204	72,130	72,130	100.0%	0	0.0%
	1B	1	15,261	34,567	23,620	68.3%	10,947	31.7%
	2	2	7,238	21,418	1,745	8.1%	19,673	91.9%
		3	4,557	20,863	3,432	16.5%	17,431	83.5%
		4	3,593	20,776	3,992	19.2%	16,784	80.8%
		Total	15,388	63,057	9,169	14.5%	53,888	85.5%
	Total		60,853	169,754	104,919	61.8%	64,835	38.2%

19 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).
20 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. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
21 156 FERC ¶ 61,180 (2016).
22 See FERC Docket No. EL16-6-003.

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 the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that 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 recommended for inclusion in the PJM RTEP process.[23] But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

For the 2018/2019 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the 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.

Table 13-4 shows the MW quantity and count of overloaded facilities and the reasons for the modeled overload. In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM was required to raise the modeled capacity limits on 72 facility/contingency pairs, 24 of which were internal to PJM and the rest were in MISO, a total of 5,858 MW.[24]

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June27, 2019) at 22.
24 PJM. "*PJM 2018/2019 Stage 1A Over allocation notice*,"<http://www.pjm.com/-/media/markets-ops/ftr/annual-arr-allocation/2018-2019/2018-2019-stage-1a-over-allocation-notice.ashx?la=en> (June 13, 2018).

Table 13-4 Stage 1A overloaded facility reasons and MW

Reason	Type	MW	Count
Network Load	M2M Flowgate	1,137	21
Network Load	Pseudo Tie Flowgate	98	3
Transmission Outage	Internal PJM	3,600	38
Transmission Outage	M2M Flowgate	983	9
Transmission Outage	Pseudo Tie Flowgate	40	1

Figure 13-1 shows the predicted and estimated impact of Stage 1A infeasibilities on funding for the 2012/2013 through 2017/2018 planning periods, as well as the predicted impact on funding for the 2019/2020 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 is self scheduled, and uses the hourly congestion LMP values of the applicable day-ahead hours. In the 2016/2017 planning period, Stage 1A ARR infeasibilities accounted for $293.5 million in estimated over allocation. Predicted funding impacts are lower in the 2017/2018, 2018/2019 and 2019/2020 planning periods from the previous two planning periods, likely as a result of PJM relaxing model constraints. PJM's newly implemented Qualified Replacement Resource rules may slightly reduce revenue inadequacy from Stage 1A ARRs, but do not eliminate the actual issues with historical Stage 1A resources.

Figure 13-1 Stage 1A Infeasibility funding impact

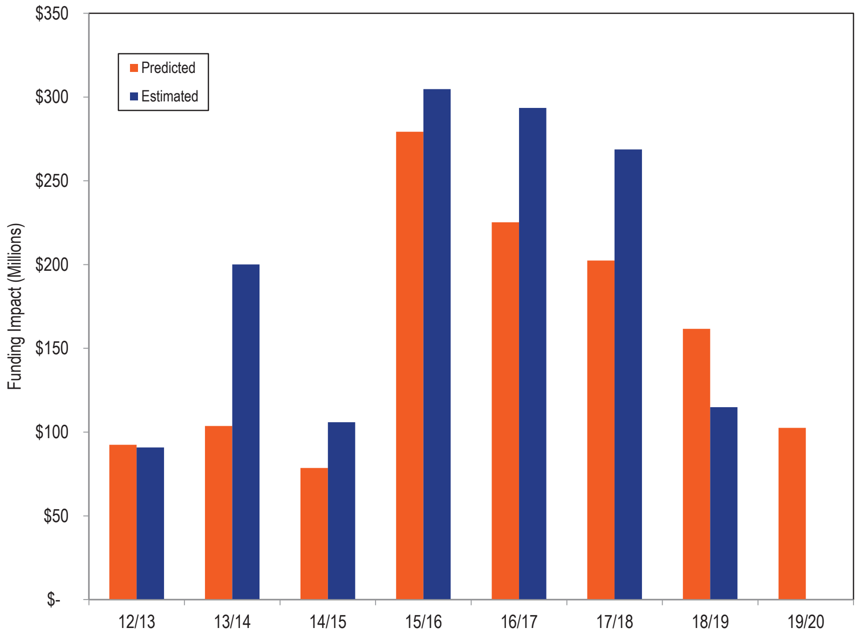


Table 13-5 shows the MW of retired generation sources for Stage 1A ARRs, the QRR MW assigned by PJM for all resources and the replacement MW that were considered rate-based. PJM created the synthetic zone Midatlantic for the QRR assignment although it is not clear why.

Table 13-5 Qualified Replacement Resource results: 2019/2020

Zone	Historical Retired	Replacement (All)	Replacement (Rate-based)
AEP/DAY	8,826.3	6,702.4	1,838.3
ATSI	4,027.3	2,463.4	50.4
ComEd	5,646.8	4,440.5	4.5
DEOK	2,318.0	1,729.2	57.6
Dominion	3,071.1	2,679.4	2,628.4
DLCO	834.0	211.7	0.0
EKPC	198.1	229.3	0.0
Midatlantic	16,813.8	14,044.3	375.9
Total	41,735.4	32,500.2	4,955.1

Revenue

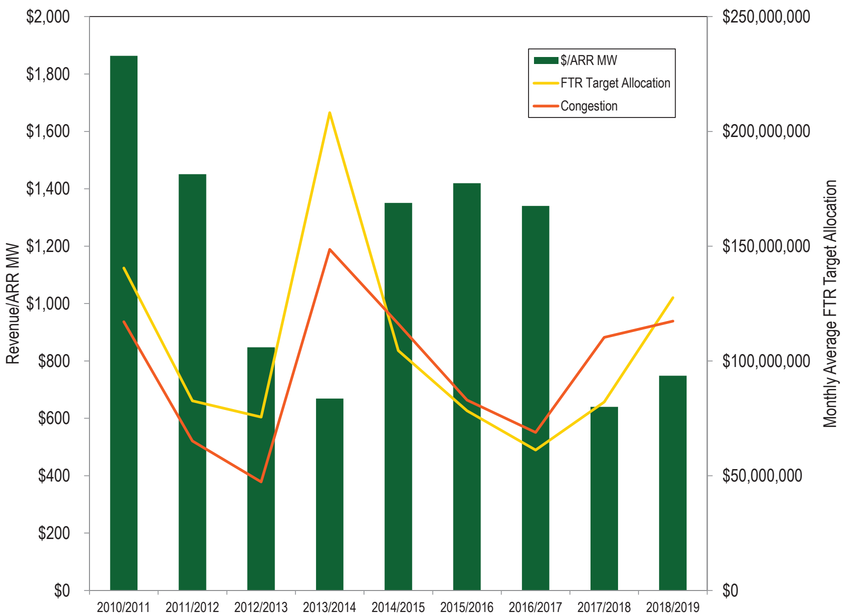
ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions which generally exceeds the sum of the ARR target allocations.

Figure 13-2 shows the revenue per ARR MW held for each month of the 2010/2011 planning period through the 2018/2019 planning period. The revenue per ARR MW held do not include target allocation related payouts for self scheduled FTRs, but do include Residual ARRs starting in August 2012.

FTR prices increased in the 2014/2015 Annual FTR Auction in part as a result of reduced supply caused by PJM's assumption of more outages in the model used to allocate Stage 1B and Stage 2 ARRs. The increased FTR prices resulted in an increase in revenue per ARR MW, but fewer ARR MW. For the 2014/2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in revenue per MW of $6,692, a 68.5 percent increase in revenue per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015/2016 and 2016/2017 planning periods, the revenue per MW of ARR allocation was $10,641.54 and $10,411. During these planning periods PJM chose more restrictive modeling criteria, which did not release the full capacity of the FTR model to account for revenue inadequacies. Beginning in the 2017/2018 planning period, when balancing congestion was removed from FTR funding, PJM reinstated less restrictive modeling criteria, and the revenue per MW of ARR decreased. For the 2017/2018 and 2018/2019 planning periods the revenue per MW of ARR was $5,168 and $6,841.

The revenue per MW value of ARRs for the 2018/2019 planning period increased 32.4 percent from the previous planning period. Figure 13-2 shows that the total congestion and FTR target allocations increased from last planning period, primarily from a very high congestion in January 2018, but that ARR value was significantly lower. Load is now paying balancing congestion costs, not accounted for in this figure, reducing revenue received by ARR holders while not receiving the asserted benefit of higher ARR value that proponents of balancing congestion reallocation had asserted would be forthcoming.

Figure 13-2 Revenue per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2018/2019



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 in 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. 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 may be reassigned multiple times over a planning period. Residual ARRs are also subject to reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned in the 2017/2018 planning period. There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned for the 2018/2019 planning period.

Table 13-6 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2017 and May 2019.

25 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

Table 13-6 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2017 through May 2019

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2017/2018 (12 months)	2018/2019 (12 months)	2017/2018 (12 months)	2018/2019 (12 months)
AECO	438	392	$3.2	$2.1
AEP	2,271	2,730	$13.0	$35.0
APS	1,660	945	$19.7	$17.6
ATSI	6,235	4,923	$20.6	$49.9
BGE	2,688	1,732	$57.7	$46.1
ComEd	4,519	3,261	$77.0	$43.9
DAY	1,565	718	$2.8	$3.7
DEOK	4,318	2,442	$23.4	$60.3
DLCO	5,995	4,576	$18.5	$44.6
DPL	1,865	1,932	$36.5	$43.3
Dominion	13	70	$0.1	$0.6
EKPC	0	0	$0.0	$0.0
JCPL	1,146	1,172	$2.4	$1.6
Met-Ed	678	604	$5.6	$4.7
PECO	3,226	2,997	$11.1	$20.9
PENELEC	696	716	$7.3	$8.4
PPL	3,447	3,643	$3.2	$8.0
PSEG	1,495	1,195	$18.6	$14.2
Pepco	2,423	1,477	$18.9	$18.1
RECO	147	46	$0.0	$0.0
Total	44,823	35,571	$339.5	$423.1

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs are effective for single months, and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant 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. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[26]

Table 13-7 shows the Residual ARRs (cleared volume) allocated to participants, along with the target allocations (bid and requested) from the effective month. In the 2018/2019 planning period, PJM allocated a total of 27,335.6 MW of Residual ARRs with a target allocation of $11.8 million. In the same time period for the 2017/2018 planning period, PJM allocated a total of 39,597.4 MW of residual ARRs with a target allocation of $17.5 million. In the 2017/2018 planning period planning period, PJM allocated a total of 39,597.4 MW of residual ARRs, up from 35,034.9 MW for the 2016/2017 planning period. Residual ARRs had a total target allocation of $17.5 million for the 2017/2018 planning period, up from $7.0 million for the 2016/2017 planning period. In prior planning years, PJM's modeling of excess outages resulted in the allocation of some ARRs that could have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-7 Residual ARR allocation volume and target allocation: 2019

Month	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-19	3,964.1	2,796.7	70.6%	$2,764,132
Feb-19	3,399.5	2,455.6	72.2%	$1,380,364
Mar-19	2,737.7	2,109.3	77.0%	$850,832
Apr-19	6,180.9	2,022.1	32.7%	$467,726
May-19	7,105.6	2,488.6	35.0%	$676,447
Jun-19	2,016.0	1,633.8	81.0%	$795,709
Total	25,403.8	13,506.1	53.2%	$6,935,210

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. The value of the day-ahead congestion price differences, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion

26 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

prices rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to pay into the FTR market, helping fund positively valued FTRs. With the reallocation of balancing congestion and M2M payments to load, available revenue to pay FTR holders in a given month is based on the amount of day-ahead congestion, payments by holders of negatively valued FTRs, additional auction revenues available at the end of a month over ARR target allocations, any charges made to day-ahead operating reserves and any surplus revenue from preceding months in these categories. At the end of the planning period, any surplus revenue from these categories is distributed proportionally to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour 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 because if the FTR market is revenue inadequate for the planning period, each participant is charged an FTR uplift proportional to their FTR target allocations. 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.

Auction market participants are free to request FTRs between any eligible pricing nodes on the system. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. For the Annual FTR Auction and FTRs bought for a quarterly period in the monthly auction, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. An FTR bought in the Monthly FTR Auction for any single calendar month following that auction may include any bus for which an LMP is calculated in the FTR model used. 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.

On December 1, 2018, PJM integrated the Ohio Valley Electric Cooperative (OVEC) joined PJM as a zone. Any FTRs mapped to the previous OVEC interface were remapped to the OVEC zonal aggregate, which is the same definition as the current OVEC Interface. The OVEC Interface was only available for sell offers beginning in the December 2018 Monthly FTR Auction and is no longer biddable.

Market Structure

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. Self scheduled FTRs represent the choice by an ARR holder to be paid based on actual day-ahead congestion revenue rather than the fixed ARR value determined 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 three types of auction for FTRs. The objective function of all FTR auctions is to maximize the bid based value of FTRs awarded in each auction. PJM conducts an Annual FTR Auction, Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period and a Long Term FTR Auction for the following three consecutive planning years.[27] FTR options are not available in the Long Term FTR Auction.

A self scheduled FTR must have the same source and sink points as the ARR and be a 24 hour obligation product. Self scheduled FTRs may not designate a price bid; rather their price is determined by the clearing price in the annual FTR auction. From a settlements perspective, the self scheduling participant is paid their ARR target allocation, which is then immediately used to pay their FTR's buy price. The participant then receives the hourly congestion LMP difference of their source and sink points as any other FTR would.

A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets. FTR self scheduled bids by ARR holders are available only as obligations for the 24 hour product and only in the Annual FTR Auction.

Supply and Demand

Total FTR supply is limited by the capability of the transmission system, in each auction, included in the PJM FTR market model as modified, for example, by PJM assumptions about outages. PJM may also limit available capability through subjective judgment exercised without any clear guidelines. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction. Long Term FTR Auction capability is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids. Any ARR MW that clear are reserved for ARR holders in their effective planning periods, and are removed from the Long Term FTR Auction capability. This does not, and cannot, preserve all possible capacity for ARR holders before a long term auction due to changes in system topology and outage selection between planning periods. Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

Depending on assumptions used in the auction transmission model, the total FTR supply can be greater than or less than system capability in aggregate and/or on a path basis. FTR supply greater than system capability contributes to FTR revenue inadequacy relative to target allocations. FTR supply less than system capability contributes to FTR revenue surplus relative to target allocations.

PJM can also make further subjective adjustments to the auction model to manage FTR revenues. PJM can assume arbitrarily higher outage levels and PJM can decide to include additional constraints (closed loop interfaces) both of which reduce system capability in the auction model. These PJM actions reduce the supply of available Stage 1B and Stage 2 ARRs, which in turn reduce the number of FTRs available for purchase. PJM made very significant adjustments starting in the 2014/2015 planning period auction model through the 2016/2017 planning period.

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.[28] 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

27 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

28 See the *2018 State of the Market Report for PJM*, Volume 2, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual system capabilities.

Long Term FTR Auctions

In July 2006, FERC issued a Final Rule mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets (FERC Docket No. RM06-8-000; Order No. 681).[29] FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights." Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design.

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all allocated ARRs are self scheduled as FTRs. PJM expands the available transmission capacity for the Long Term FTR Auction by removing all the transmission outages included in the model when allocating ARRs.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM has implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The PJM proposal revises the determination of ARR rights that are reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM would rerun the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and use the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The resulting difference between the revised set of ARRs and ARR/FTR market models' system capability, without outages, would determine the residual capability offered in the Long Term FTR auction. This method will provide ARR holders with a more accurate representation of capacity that will carry into the Annual FTR Auction than is currently preserved for ARR holders. Capacity awarded in the Long Term FTR Auction is modeled as a fixed injection/withdrawal in the Annual FTR Auction, and is therefore unavailable in preceding auctions. While the new rules will improve the allocation of congestion rights to ARR holders, a proportion of congestion revenues will still be assigned to the Long Term FTR Auction without ever having been made available to ARR holders. Due to the duration of long term FTRs and the inconstant nature of the ARR/FTR model's outage selections and system topology, reserving the previous year's ARR bids does not fully capture all of the capability that should be available to ARR holders. Any capability that is auctioned in the Long Term FTR Auction and that should otherwise be available to ARR holders results in lost revenue to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design.

The 2009/2012 and 2010/2013 Long Term FTR Auctions consisted of two rounds.[30] Subsequent Long Term FTR Auctions consist of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one of the next three. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- Round 1. The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction and uses PJM's Summer Model build. Market participants make offers for FTRs between any source and sink.
- Round 2. The second round is conducted in September, uses the Summer Model build and follows the same rules as Round 1.

29 116 FERC ¶ 61,077 (2006).

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

- Round 3. The third round is conducted in December, uses the Fall Model build and follows the same rules as Round 1.

Annual FTR Auctions

Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[31] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

The FTRs sold in the Long Term FTR Auction for a future delivery year may conflict with the ARRs assigned to load in the ARR allocation process when that delivery year is effective. By not properly reserving all ARR capacity in the Long Term FTR Auction, it is possible that a SFT violation may occur between a long term FTR and a self scheduled ARR, resulting in revenue adequacy issues.

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. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[32] Beginning with the 2018/2019 planning period, to address performance issues in solving the Monthly Balance of Planning Period Auctions, participants may no longer place bids that overlap three available monthly periods.[33] For example, participants cannot place a bid for Quarter 1 in the June auction because that quarter overlaps three individual month periods.

31 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

32 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

33 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

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 more restrictive start and end times, meaning that 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.

Patterns of Ownership

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, trading firms 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.

The HHI is commonly used to measure market concentration with a HHI of 10000 indicating a monopoly. The "Merger Policy Statement" of FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[34]

Table 13-8 shows the 2019/2022 long term FTR auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 68.1 percent of prevailing flow buy bid FTRs and 70.4 percent of counter flow buy bid FTRs with the result that financial entities purchased 69.1 percent of all long term FTR auction cleared buy bids. Physical entities purchased 30.9 percent of all cleared long term FTRs in the 2019/2022 Long Term FTR Auction, up 5.0 percentage points from the previous Long Term FTR Auction.

Table 13-8 Long term FTR auction patterns of ownership by FTR direction: 2019/2022

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	31.9%	29.6%	30.9%
	Financial	68.1%	70.4%	69.1%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	20.7%	23.5%	21.7%
	Financial	79.3%	76.5%	78.3%
	Total	100.0%	100.0%	100.0%

34 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).

Table 13-9 shows the HHI for the periods in the 2017/2020 through 2019/2022 Long Term FTR Auctions. The YRALL auction is Highly Concentrated. The individual annual auctions are Unconcentrated with the exception of years two and three of the 17/20 Auction.

Table 13-9 Long term HHIs by auction

Auction	YR1	YR2	YR3	YRALL
17/20 Long Term Auction	462	1696	1252	8533
18/21 Long Term Auction	586	850	577	8654
19/22 Long Term Auction	344	521	666	9954

Table 13-10 shows the annual FTR auction cleared FTRs for the 2019/2020 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2019/2020 planning period, financial entities purchased 64.8 percent of prevailing flow FTRs, down 2.1 percentage points, and 79.5 percent of counter flow FTRs, down 4.7 percentage points, with the results that financial entities purchased 69.8 percent, down 3.0 percentage points, of all annual FTR auction cleared buy bids for the 2019/2020 planning period.

Table 13-10 Annual FTR Auction patterns of ownership by FTR direction: 2019/2020

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	6.8%	0.3%	4.5%
		No	28.4%	20.3%	25.7%
		Total	35.2%	20.5%	30.2%
	Financial	No	64.8%	79.5%	69.8%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		18.0%	20.0%	18.8%
	Financial		82.0%	80.0%	81.2%
	Total		100.0%	100.0%	100.0%

Table 13-11 shows the HHI values for cleared buy and self scheduled bids for the 2016/2017 through 2018/2019 Annual FTR Auctions. Obligation buy bids are consistently Unconcentrated, while Option buy bids are Unconcentrated to Moderately Concentrated. Cleared self scheduled bids are always Highly Concentrated.

Table 13-11 Annual auction HHIs by auction

Auction	Offset Type	Trade Type	HHI
19/20 Annual Auction	Obligation	Buy	251
	Obligation	SelfScheduled	2661
	Option	Buy	978
18/19 Annual Auction	Obligation	Buy	357
	Obligation	SelfScheduled	2620
	Option	Buy	1213
17/18 Annual Auction	Obligation	Buy	303
	Obligation	SelfScheduled	2794
	Option	Buy	2099

Table 13-12 presents the monthly balance of planning period FTR auction cleared FTRs for 2019 by trade type, organization type and FTR direction. Financial entities purchased 72.3 percent of prevailing flow FTRs, down 0.4 percentage points, and 81.5 percent of counter flow FTRs, down 0.7 percentage points, for the year, with the result that financial entities purchased 76.4 percent, down 0.6 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for 2019.

Table 13-12 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2019

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	27.7%	18.5%	23.6%
	Financial	72.3%	81.5%	76.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	14.9%	14.3%	14.7%
	Financial	85.1%	85.7%	85.3%
	Total	100.0%	100.0%	100.0%

Table 13-13 shows the HHI values for cleared MW for the 2018/2019 planning period monthly auctions by period. Cleared obligation buy bids are Unconcentrated or Moderately Concentrated. Cleared option buy bids range from Unconcentrated to Highly Concentrated.

Table 13-13 Monthly Balance of Planning Period FTR Auction HHIs by period

Auction	Hedge Type	Prompt Month	Prompt Month+1	Prompt Month+2	Q2	Q3	Q4
Jun-18	Obligation	353	432	487	587	659	773
	Option	3796	5981	7006	4854	4761	6586
Jul-18	Obligation	329	434	1283	827	559	681
	Option	2270	5044	2751	3666	3918	6260
Aug-18	Obligation	254	534	527	509	430	522
	Option	2437	3135	4673	5486	4729	5578
Sep-18	Obligation	330	481	534		610	772
	Option	1412	4864	3118		1622	4876
Oct-18	Obligation	378	457	834		478	678
	Option	1192	1938	3884		1892	4399
Nov-18	Obligation	329	591	641		523	580
	Option	1337	1715	2610		1650	2312
Dec-18	Obligation	327	456	546			685
	Option	1255	1944	1662			2038
Jan-19	Obligation	320	382	879			629
	Option	1515	2709	4218			1485
Feb-19	Obligation	263	372	566			735
	Option	1248	2064	3847			2534
Mar-19	Obligation	287	387	396			
	Option	1163	2853	2805			
Apr-19	Obligation	255	423				
	Option	1012	3136				
May-19	Obligation	314					
	Option	1226					

Table 13-14 shows the average daily net position ownership for all FTRs for 2019, by FTR direction.

Table 13-14 Daily FTR net position ownership by FTR direction: 2019

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	36.1%	18.3%	28.8%
Financial	63.9%	81.7%	71.2%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits (rather than the inflated limits used in Stage 1A) in the FTR auction model. If, in PJM's judgment, the normal capability limit is not consistent with revenue adequacy goals and simultaneous feasibility, then FTR Auction capability reductions are undertaken pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[35] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[36] The use of both of these procedures is contingent on PJM actions not affecting the revenue adequacy of allocated ARRs, all requested self scheduled FTRs clear and net FTR auction revenue is positive.

Long Term FTR Auction

In the 2019/2022 Long Term FTR Auction, 179,727 MW (36.7 percent of bid volume; 44.0 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 164,911 MW and 47.7 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 228,510 MW (15.6 percent of bid volume; 60.0 percent of total FTR volume) an increase from 180,596 MW and 52.3 percent of total FTR volume. In the 2019/2022 Long Term FTR Auction, there were 12,790 MW (7.4 percent) of counter flow sell offers and 22,622 MW (15.6 percent) of prevailing flow sell offers cleared.

Table 13-15 Long Term FTR Auction market volume: 2019/2022

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	77,290	222,831	80,816	36.3%	142,015	63.7%
		Year 2	56,949	151,934	53,512	35.2%	98,423	64.8%
		Year 3	45,133	111,957	43,417	38.8%	68,540	61.2%
		Year All	428	2,681	1,983	74.0%	698	26.0%
		Total	179,800	489,404	179,727	36.7%	309,677	63.3%
	Prevailing Flow	Year 1	195,478	664,524	105,442	15.9%	559,081	84.1%
		Year 2	134,844	431,316	69,639	16.1%	361,677	83.9%
		Year 3	103,713	350,104	53,232	15.2%	296,872	84.8%
		Year All	2,325	14,199	197	1.4%	14,001	98.6%
		Total	436,360	1,460,142	228,510	15.6%	1,231,632	84.4%
	Total		616,160	1,949,546	408,237	20.9%	1,541,309	79.1%
Sell offers	Counter Flow	Year 1	46,482	110,181	8,634	7.8%	101,547	92.2%
		Year 2	17,352	47,115	3,800	8.1%	43,315	91.9%
		Year 3	6,538	15,802	355	2.2%	15,447	97.8%
		Year All	NA	NA	NA	NA	NA	NA
		Total	70,372	173,098	12,790	7.4%	160,308	92.6%
	Prevailing Flow	Year 1	33,785	78,017	14,373	18.4%	63,644	81.6%
		Year 2	17,460	44,902	6,529	14.5%	38,373	85.5%
		Year 3	9,488	22,005	1,720	7.8%	20,285	92.2%
		Year All	NA	NA	NA	NA	NA	NA
		Total	60,733	144,924	22,622	15.6%	122,301	84.4%
	Total		131,105	318,022	35,412	11.1%	282,610	88.9%

35 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).
36 See id.

Figure 13-3 shows the percent of FTR MW cleared, and bid and cleared volume, by direction, for each round of the Long Term FTR Auction from the 2015/2018 through the 2019/2022 auctions.

Figure 13-3 Long Term FTR Auction bid and cleared volume by round and direction

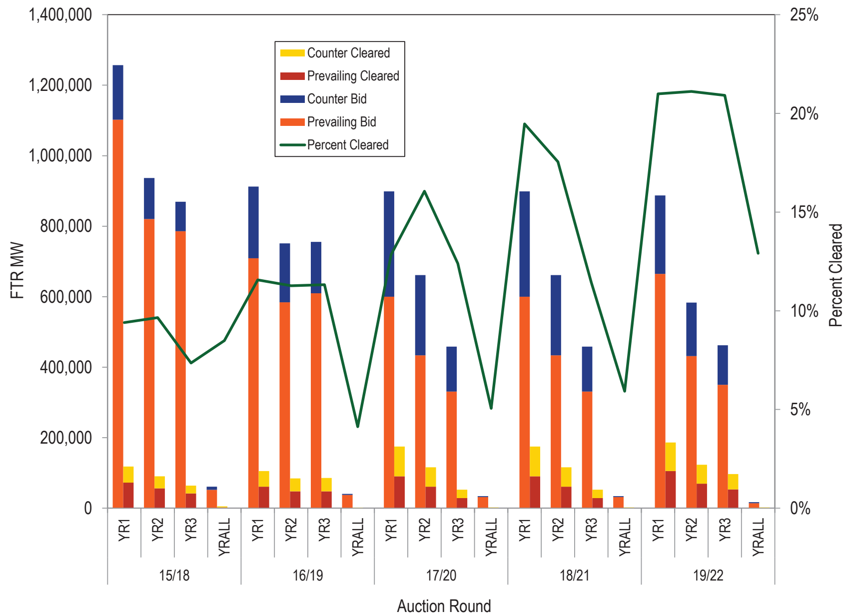


Table 13-16 compares cleared FTR obligations (not options) acquired in the Long Term FTR Auctions to the total cleared FTR obligations from the Annual FTR Auction, for FTRs in the 2014/2015 through 2019/2020 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 41.5 percent of total FTR volume in the 2014/2015 through 2019/2020 planning periods.

Table 13-16 Long Term and Annual Auction total cleared FTR MW

	Long Term FTR Product (Including YRALL)			Obligation Volume (MW)		
Effective Planning Period	YR3	YR2	YR1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Cleared
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%
2018/2019	87,232	109,827	176,998	374,057	549,669	40.5%
2019/2020	80,947	118,112	188,438	387,496	576,937	40.2%

Annual FTR Auction

Table 13-17 shows the annual FTR auction market volume for the 2019/2020 planning period. Total FTR buy bids were 2,787,716 MW, down 3.2 percent from 2,880,105 MW for the previous planning period. For the 2019/2020 planning period 611,878 MW (32.8 percent) of buy bids cleared, up 12.4 percentage points from 587,755 MW for the previous planning period. There were 375,583 MW of sell offers with 62,103 MW (16.5 percent) clearing for the 2019/2020 planning period. The total volume of cleared buy and self scheduled bids was 641,023 MW, up 4.2 percent from 615,254 MW in the previous Annual FTR Auction.

Table 13-17 Annual FTR Auction market volume: 2019/2020

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	222,525	665,370	218,484	32.8%	446,886	67.2%
		Prevailing Flow	488,843	1,650,028	329,308	20.0%	1,320,720	80.0%
		Total	711,368	2,315,397	547,792	23.7%	1,767,606	76.3%
	Options	Counter Flow	41	1,335	52	3.9%	1,283	96.1%
		Prevailing Flow	38,110	470,983	64,034	13.6%	406,949	86.4%
		Total	38,151	472,318	64,086	13.6%	408,232	86.4%
	Total	Counter Flow	222,566	666,705	218,536	32.8%	448,169	67.2%
		Prevailing Flow	526,953	2,121,011	393,342	18.5%	1,727,669	81.5%
		Total	749,519	2,787,716	611,878	21.9%	2,175,838	78.1%
Self-scheduled bids	Obligations	Counter Flow	196	592	592	100.0%	0	0.0%
		Prevailing Flow	3,624	28,554	28,554	100.0%	0	0.0%
		Total	3,820	29,146	29,146	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	222,721	665,962	219,076	32.9%	446,886	67.1%
		Prevailing Flow	492,467	1,678,581	357,861	21.3%	1,320,720	78.7%
		Total	715,188	2,344,543	576,937	24.6%	1,767,606	75.4%
	Options	Counter Flow	41	1,335	52	3.9%	1,283	96.1%
		Prevailing Flow	38,110	470,983	64,034	13.6%	406,949	86.4%
		Total	38,151	472,318	64,086	13.6%	408,232	86.4%
	Total	Counter Flow	222,762	667,297	219,128	32.8%	448,169	67.2%
		Prevailing Flow	530,577	2,149,564	421,895	19.6%	1,727,669	80.4%
		Total	753,339	2,816,861	641,023	22.8%	2,175,838	77.2%
Sell offers	Obligations	Counter Flow	62,099	148,782	23,340	15.7%	125,443	84.3%
		Prevailing Flow	91,175	208,379	37,751	18.1%	170,627	81.9%
		Total	153,274	357,161	61,091	17.1%	296,070	82.9%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	1,238	18,422	1,012	5.5%	17,410	94.5%
		Total	1,238	18,422	1,012	5.5%	17,410	94.5%
	Total	Counter Flow	62,099	148,782	23,340	15.7%	125,443	84.3%
		Prevailing Flow	92,413	226,801	38,763	17.1%	188,037	82.9%
		Total	154,512	375,583	62,103	16.5%	313,480	83.5%

Figure 13-4 shows the percent of FTR MW cleared and bid and cleared volume, by direction, for each round of the Annual FTR Auction from the 2015/2016 planning period through the 2019/2020 planning period.

Figure 13-4 Annual FTR Auction bid and cleared volume by round and direction

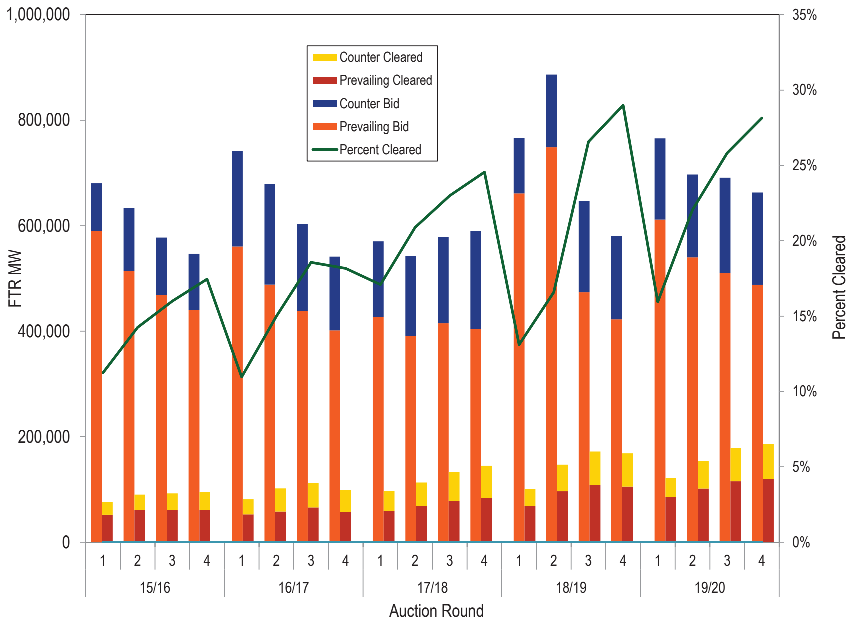


Figure 13-5 shows the proportion of ARRs self scheduled as FTRs for the last eleven planning periods. The maximum possible level of self scheduled FTRs is equal to total ARRs. Eligible participants self scheduled 29,146 MW (27.6 percent) of ARRs as FTRs for the 2019/2020 planning period, up from 27,479 MW (25.9 percent) in the previous planning period.

Figure 13-5 Comparison of self scheduled FTRs: 2009/2010 through 2019/2020

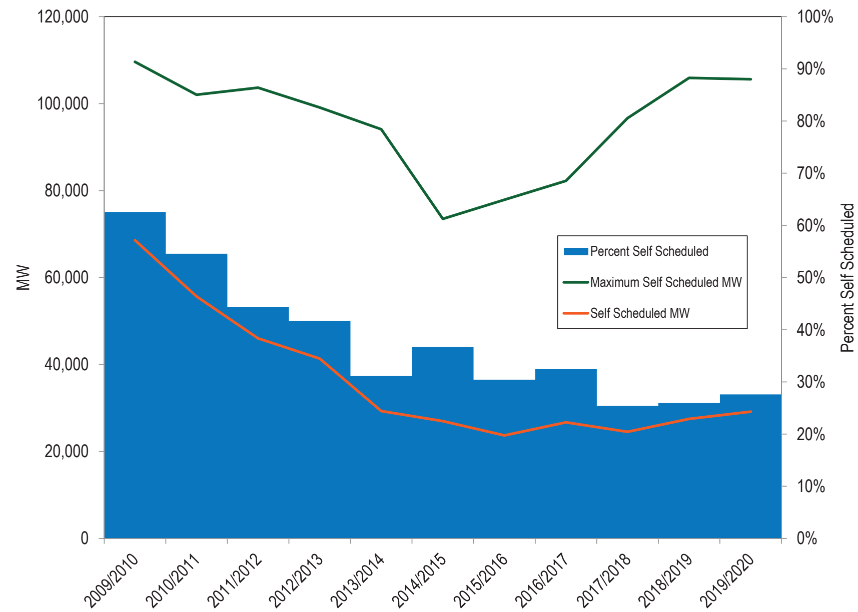


Table 13-18 shows the relationship between source and sink node type market share in the cleared buy and self scheduled bids for all FTRs in the 2019/2020 Annual FTR Auction.

Generator to generator FTRs comprise 49.2 percent of all cleared FTR buy and self scheduled bids, up 0.9 percentage points from the previous planning period. It is not clear why generator to generator FTRs make up such a disproportionate share of total FTRs. Congestion results from load paying more for generation than generators receive. By definition, congestion is between generator sources and load sinks. Generator to generator paths do not represent the delivery of generation to load. FTRs between generators simply create a speculative opportunity because they can be a low cost or zero cost FTR in the current design with a significant payoff if there is a price difference between the two nodes.

The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load.

Table 13-18 Annual auction FTR node type matrix: 2019/2020

	Sink Type							
Source Type	Aggregate	EHV Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.6%	0.0%	5.8%	0.2%	0.1%	0.3%	0.2%	0.3%
EHV Aggregate	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Generator	10.9%	0.1%	49.2%	3.9%	0.8%	3.6%	4.7%	7.1%
Hub	0.2%	0.0%	0.5%	0.6%	0.1%	0.0%	0.2%	2.2%
Interface	0.1%	0.0%	0.4%	0.0%	0.1%	0.0%	0.1%	0.1%
Load	0.6%	0.0%	2.3%	0.0%	0.0%	0.3%	0.0%	0.1%
Residual Metered Aggregate	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%
Zone	0.3%	0.0%	0.6%	0.4%	0.1%	0.0%	0.5%	0.8%

Table 13-19 shows the node type cleared market shares for option bids in the 2019/2020 Annual FTR Auction.

Table 13-19 Annual auction FTR node type matrix: 2019/2020 Options

	Sink Type					
Source Type	Aggregate	Generator	Hub	Interface	Load	Zone
Aggregate	6.0%	2.0%	0.4%	0.1%	0.0%	0.7%
Generator	42.1%	2.0%	5.2%	2.9%	0.0%	26.7%
Hub	0.1%	1.4%	0.2%	0.0%	0.1%	1.1%
Interface	0.1%	1.1%	0.0%	0.0%	0.0%	0.0%
Load	2.6%	0.0%	0.1%	0.0%	0.0%	0.9%
Residual Metered Aggregate	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Zone	0.9%	1.7%	0.5%	0.1%	0.2%	0.5%

Monthly Balance of Planning Period Auctions

Table 13-20 provides the monthly balance of planning period FTR auction market volume for the entire 2017/2018 and 2018/2019 planning periods. There were 19,827,194 MW of FTR obligation buy bids and 8,483,263 MW of FTR obligation sell offers for all bidding periods in the 2018/2019 planning period. The monthly balance of planning period FTR auction cleared 2,966,810 (18.9 percent) of FTR obligation buy bids and 1,237,274 MW (18.3 percent) of FTR obligation sell offers.

There were 4,168,186 MW of FTR option buy bids and 1,708,827 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period. The monthly auctions cleared 191,043 MW (4.6 percent) of FTR option buy bids, and 466,274 MW (27.3 percent) of FTR option sell offers.

Table 13-20 Monthly Balance of Planning Period FTR Auction market volume: 2019

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-19	Obligations	Buy bids	345,894	1,161,069	217,303	18.7%	943,766	81.3%
		Sell offers	223,686	499,331	79,704	16.0%	419,627	84.0%
	Options	Buy bids	6,069	89,470	9,046	10.1%	80,424	89.9%
		Sell offers	14,752	110,725	36,445	32.9%	74,280	67.1%
Feb-19	Obligations	Buy bids	397,644	1,299,918	263,448	20.3%	1,036,470	79.7%
		Sell offers	187,553	428,231	72,378	16.9%	355,852	83.1%
	Options	Buy bids	5,250	89,017	8,297	9.3%	80,720	90.7%
		Sell offers	12,207	101,025	33,532	33.2%	67,492	66.8%
Mar-19	Obligations	Buy bids	385,192	1,189,201	247,546	20.8%	941,655	79.2%
		Sell offers	316,967	647,968	111,174	17.2%	536,794	82.8%
	Options	Buy bids	4,146	103,905	13,701	13.2%	90,204	86.8%
		Sell offers	13,355	128,952	37,054	28.7%	91,899	71.3%
Apr-19	Obligations	Buy bids	303,663	999,335	198,854	19.9%	800,481	80.1%
		Sell offers	205,875	419,577	67,870	16.2%	351,707	83.8%
	Options	Buy bids	2,672	66,021	9,844	14.9%	56,177	85.1%
		Sell offers	9,430	94,794	25,509	26.9%	69,285	73.1%
May-19	Obligations	Buy bids	200,388	701,681	145,331	20.7%	556,350	79.3%
		Sell offers	94,152	219,427	40,052	18.3%	179,375	81.7%
	Options	Buy bids	1,350	23,096	5,218	22.6%	17,878	77.4%
		Sell offers	4,672	54,636	18,704	34.2%	35,932	65.8%
2017/2018*	Obligations	Buy bids	3,595,933	15,443,102	2,548,608	16.5%	12,894,494	83.5%
		Sell offers	2,057,542	3,898,145	1,001,900	25.7%	2,896,245	74.3%
	Options	Buy bids	37,328	3,695,650	59,513	1.6%	3,636,138	98.4%
		Sell offers	67,177	503,728	147,361	29.3%	356,366	70.7%
2018/2019**	Obligations	Buy bids	4,329,182	15,659,008	2,966,810	18.9%	12,692,199	81.1%
		Sell offers	2,843,624	6,774,436	1,237,274	18.3%	5,537,162	81.7%
	Options	Buy bids	84,129	4,168,186	191,043	4.6%	3,977,143	95.4%
		Sell offers	195,333	1,708,827	466,274	27.3%	1,242,553	72.7%

* Shows 12 months for 2017/2018 ** Shows 12 months for 2018/2019

Table 13-21 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 2019 was 256,233 MW. The average monthly cleared volume for 2018 was 226,127.6 MW.

Table 13-21 Monthly Balance of Planning Period FTR Auction buy bid, bid and cleared volume (MW per period): 2019

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-19	Bid	631,086	244,214	179,770				195,470	1,250,540
	Cleared	140,962	43,731	14,753				26,903	226,349
Feb-19	Bid	752,082	233,401	192,921				210,531	1,388,935
	Cleared	171,787	42,077	28,958				28,924	271,745
Mar-19	Bid	742,020	286,529	264,556				0	1,293,106
	Cleared	154,347	61,658	45,242				0	261,246
Apr-19	Bid	774,909	290,447						1,065,356
	Cleared	160,482	48,215						208,698
May-19	Bid	724,776							724,776
	Cleared	150,549							150,549
Jun-19	Bid	843,374	385,114	365,163		351,566	326,152	315,791	2,587,161
	Cleared	183,826	59,047	49,645		44,839	46,480	34,979	418,815

Secondary Bilateral Market

Table 13-22 provides the secondary bilateral FTR market volume for the entire 2017/2018 and 2018/2019 planning periods.

Table 13-22 Secondary bilateral FTR market volume: 2017/2018 and 2018/2019[37]

Planning Period	Type	Class Type	Volume (MW)
2017/2018	Obligation	24-Hour	167.4
		On Peak	8,630.0
		Off Peak	6,755.4
		Total	15,552.8
	Option	24-Hour	5.8
		On Peak	0.0
		Off Peak	0.0
		Total	5.8
2018/2019	Obligation	24-Hour	2,782.1
		On Peak	21,423.5
		Off Peak	21,636.9
		Total	45,842.5
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	40.0
		Total	40.0

Figure 13-6 shows the FTR bid, cleared and net bid volume from June 2003 through June 2019 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes 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. Volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

37 The 2018/2019 planning period covers bilateral FTRs that are effective for any time between June 1, 2017 through May 31, 2018, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-6 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through June 2019

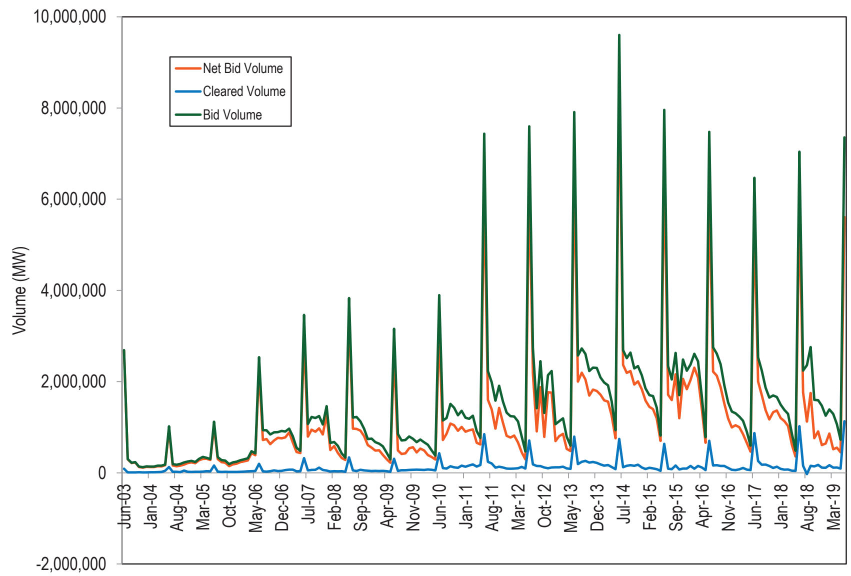
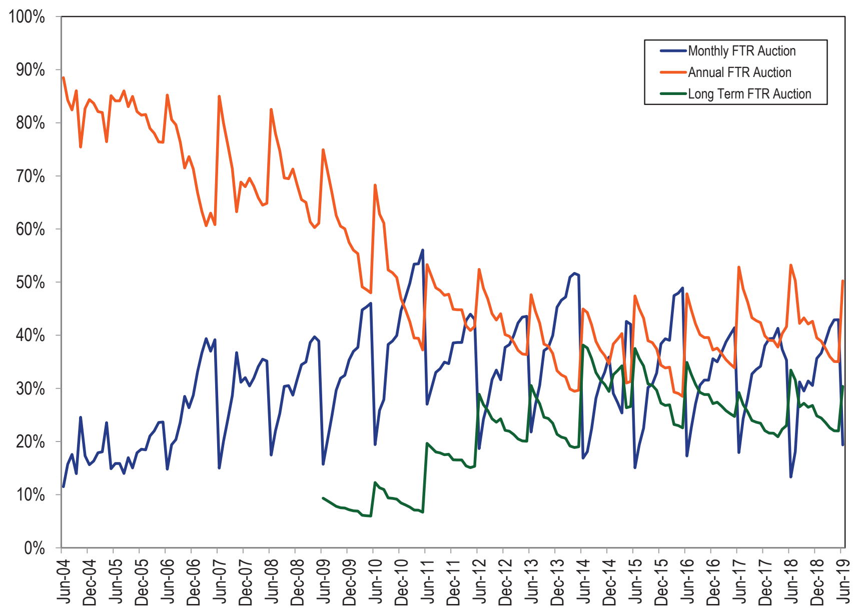


Figure 13-7 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through June 2019, by type of auction. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volume spread equally 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 any planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater percent of total 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 a corresponding increase in the share of Annual FTRs.

Figure 13-7 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through June 2019



Price

Table 13-23 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2019/2022 Long Term FTR Auction. Only FTR obligation products (no options) are available in the Long Term FTR Auctions. In this auction, weighted average buy bid counter flow and prevailing flow FTR prices were -$0.36 and $0.46, compared to -$0.41 and $0.44 from the 2018/2021 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -$0.31 and $0.43, compared to -$0.32 for counter flow FTRs and $0.35 for prevailing flow FTRs.

Table 13-23 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): 2019/2022

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.22)	($0.27)	($0.46)	($0.41)
		Year 2	($0.91)	($0.25)	($0.43)	($0.36)
		Year 3	($0.75)	($0.24)	($0.41)	($0.34)
		Year All	NA	($0.03)	($0.05)	($0.04)
		Total	($1.03)	($0.25)	($0.43)	($0.36)
	Prevailing Flow	Year 1	$0.99	$0.29	$0.52	$0.47
		Year 2	$0.96	$0.27	$0.48	$0.44
		Year 3	$1.00	$0.28	$0.51	$0.46
		Year All	NA	$0.01	$0.04	$0.03
		Total	$0.99	$0.28	$0.51	$0.46
	Total		$0.50	$0.04	$0.09	$0.10
Sell offers	Counter Flow	Year 1	($0.37)	($0.20)	($0.45)	($0.30)
		Year 2	NA	($0.18)	($0.42)	($0.27)
		Year 3	NA	($0.41)	($1.24)	($0.76)
		Year All	NA	NA	NA	NA
		Total	($0.37)	($0.20)	($0.46)	($0.31)
	Prevailing Flow	Year 1	$0.82	$0.33	$0.56	$0.46
		Year 2	$0.00	$0.24	$0.44	$0.34
		Year 3	NA	$0.37	$0.72	$0.57
		Year All	NA	NA	NA	NA
		Total	$0.82	$0.30	$0.54	$0.43
	Total		$0.70	$0.09	$0.23	$0.16

Table 13-24 shows the weighted-average cleared buy bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2019/2020 planning period. The weighted-average cleared buy bid price in the 2019/2020 Annual FTR Auction was $0.28 per MW, equal to $0.28 per MW in the 2018/2019 planning period.

Table 13-24 Annual FTR Auction weighted-average cleared prices (Dollars per MW): 2019/2020

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.59)	($0.42)	($0.24)	($0.34)
		Prevailing Flow	$1.20	$0.72	$0.37	$0.60
		Total	$0.64	$0.27	$0.12	$0.23
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.05	$0.38	$0.20	$0.27
		Total	$0.05	$0.38	$0.20	$0.27
Self-scheduled bids	Obligations	Counter Flow	($0.19)	NA	NA	($0.19)
		Prevailing Flow	$0.91	NA	NA	$0.91
		Total	$0.89	NA	NA	$0.89
Buy and self-scheduled bids	Obligations	Counter Flow	($0.56)	($0.42)	($0.24)	($0.34)
		Prevailing Flow	$1.01	$0.72	$0.37	$0.65
		Total	$0.78	$0.27	$0.12	$0.29
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.05	$0.38	$0.20	$0.27
		Total	$0.05	$0.38	$0.20	$0.27
Sell offers	Obligations	Counter Flow	($0.70)	($0.57)	($0.30)	($0.42)
		Prevailing Flow	$0.59	$0.58	$0.27	$0.43
		Total	$0.32	$0.17	$0.05	$0.11
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.31	$0.08	$0.16
		Total	$0.00	$0.31	$0.08	$0.16

Table 13-25 shows the cleared buy bid volume, cleared buy bid revenue and cleared revenue/cleared MW for the six latest planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative modeling. In the 2017/2018 Annual FTR Auction, the $/MW decreased to lower than 2013/2014 levels, due in part to the partial relaxation of PJM's conservative modeling practices due to the reassignment of balancing congestion and M2M payments to load and exports. This reduction continued into the 2018/2019 planning period. The reassignment of balancing congestion and M2M payments to load did not increase the per MW value of ARRs.

Table 13-25 Cleared volume, revenue and $/MW: 2012/2013 through 2019/2020 Annual FTR Auction

	Cleared Buy Bid Volume	Percent Cleared	Buy Bid Revenue (millions)	Buy Bid Revenue ($/MW)
2012/2013	371,295	14.5%	$627.3	$1,689
2013/2014	420,489	12.8%	$567.6	$1,350
2014/2015	365,843	11.2%	$789.7	$2,159
2015/2016	378,328	15.4%	$948.6	$2,507
2016/2017	420,198	16.2%	$918.0	$2,185
2017/2018	513,263	22.3%	$555.2	$1,082
2018/2019	587,775	20.4%	$833.4	$1,418
2019/2020	611,878	21.9%	$876.4	$1,432

Table 13-26 shows the weighted average cleared buy bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January through June 2019. For example, for the January 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 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 2019 was $0.17 per MW, down from $0.21 per MW in the same time last year, a 19.0 percent decrease in FTR prices. The cleared weighted-average price for the current planning period was $0.20, up 53.8 percent from $0.13 for the previous planning period.

Table 13-26 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy bid price per period (Dollars per MW): 2019

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-19	$0.22	$0.35	$0.16				$0.20	$0.23
Feb-19	$0.22	$0.27	$0.15				$0.15	$0.20
Mar-19	$0.16	$0.22	$0.24				$0.00	$0.19
Apr-19	$0.10	$0.17						$0.12
May-19	$0.09							$0.09
Jun-19	$0.11	$0.19	$0.20		$0.25	$0.31	$0.18	$0.20

Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR for entities that purchase FTRs. 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. ARR holders that self schedule FTRs do not receive a profit on the transaction and are trading rights to congestion revenues for a fixed payment.

The fact that FTRs have been consistently profitable for financial entities regardless of the payout ratio raises questions about the competitiveness of the market. Accounting for direct profitability and the distribution of surplus congestion revenue, FTR purchases by financial entities were not profitable in 2012/2013 and were profitable in every planning year from 2013/2014 through 2016/2017, and were profitable if summed over the entire period (Table 13-29). It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-27 lists FTR profits by organization type and FTR direction for the 2018/2019 planning period. Some participants classified as physical, such as a company that holds one generator, are not eligible for ARRs but do have a physical presence on the PJM system are classified in the physical category. FTR profits are the sum of the daily FTR target allocations, adjusted by the payout ratio minus the daily FTR auction costs for each FTR (not self scheduled) held by an organization. Self scheduled FTRs can have a negative value, depending on the congestion on the FTR path. 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 FTR credits also do not include any excess congestion revenue distributions made at the end of the planning period. 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. FTR profitability is the difference between the revenue received for an FTR and the cost of that FTR, not including self scheduled FTRs. Self scheduled FTRs represent a return of congestion revenue to ARR holders, and are not profits. In the 2018/2019 planning period, companies made profits of $194.0 million. ARR holders who self scheduled FTRs received $129.9 million in congestion revenues. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion rather than profits.

Table 13-27 FTR profits and revenues by organization type and FTR direction: 2018/2019

	FTR Direction				
Organization Type	Prevailing Flow Profit	Self Scheduled Prevailing Flow Revenue Returned	Counter Flow Profit	Self Scheduled Counter Flow Revenue Returned	All
Financial	($134,048,844)	$0	$250,544,104	$0	$116,495,260
Physical	($149,886,373)	$127,257,187	$97,557,416	$2,625,897	$77,554,127
Total	($283,935,218)	$127,257,187	$348,101,520	$2,625,897	$194,049,386

Table 13-28 lists the monthly FTR profits for the 2017/2018 and the 2018/2019 planning periods by organization type. FTR revenues for ARR holders who self schedule are not included. FTR profits for ARR holders who purchase FTRs in auctions are included.

Table 13-28 Monthly FTR profits by organization type: 2017/2018 and 2018/2019

	Organization Type		
Month	Physical	Financial	Total
Jun-17	$764,708	$14,019,198	$14,783,906
Jul-17	($2,987,829)	$7,306,611	$4,318,783
Aug-17	($3,234,012)	$2,414,244	($819,767)
Sep-17	$2,168,231	$22,644,485	$24,812,716
Oct-17	$777,230	$14,400,509	$15,177,739
Nov-17	$2,350,616	$3,244,972	$5,595,588
Dec-17	$820,082	$23,681,735	$24,501,817
Jan-18	$32,871,784	$103,179,520	$136,051,304
Feb-18	$317,895	($2,047,899)	($1,730,004)
Mar-18	$8,526,358	$13,327,501	$21,853,859
Apr-18	$574,714	$7,467,985	$8,042,698
May-18	$10,386,785	$36,679,052	$47,065,837
Summary for Planning Period 2017/2018			
Total	$53,336,562	$246,317,915	$299,654,477
Jun-18	$8,959,001	$16,374,714	$25,333,715
Jul-18	($7,329,905)	$8,826,482	$1,496,576
Aug-18	($2,093,482)	$6,880,524	$4,787,043
Sep-18	$19,875,921	$16,799,058	$36,674,979
Oct-18	$9,065,717	$20,328,429	$29,394,146
Nov-18	$7,892,354	$8,051,851	$15,944,205
Dec-18	($4,074,003)	$16,403,516	$12,329,514
Jan-19	($55,670)	$41,735,751	$41,680,080
Feb-19	($26,059,909)	($621,454)	($26,681,363)
Mar-19	($17,165,099)	$210,844	($16,954,255)
Apr-19	($25,737,657)	($12,160,549)	($37,898,206)
May-19	($15,606,225)	($6,333,907)	($21,940,132)
Summary for Planning Period 2018/2019			
Total	($52,328,957)	$116,495,260	$64,166,303

Table 13-29 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period, excluding revenue to self scheduled FTRs for physical participants. The profits include any end of planning period surplus distribution or uplift, where applicable, that will impact total profitability. The surplus or uplift is distributed prorata based on positive target allocations until the 2018/2019 planning period. Beginning with the 2018/2019 planning period annual surplus congestion revenue was distributed to ARR holders. The surplus row indicates the surplus congestion revenue collected from the FTR market for the entire planning period. When positive, it is a payout to FTRs distributed prorata, which includes surplus ARR auction revenue and surplus day-ahead congestion revenue. When negative, it is a payment made to FTRs, pro-rata, by all FTR holders to meet revenue adequacy.

Table 13-29 FTR profits by organization type: 2012/2013 through 2018/2019

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Financial	Profit	$63,457,511	$557,583,317	$236,692,290	$41,264,165	($13,519,824)	$246,317,915	$116,495,260
	Surplus	($80,450,357)	($256,820,253)	$44,410,625	$11,897,525	$20,968,663	$147,413,287	
	Total	($16,992,846)	$300,763,064	$281,102,915	$53,161,690	$7,448,839	$393,731,202	$116,495,260
Physical	Profit	($65,702,875)	$401,144,350	$160,694,399	$22,585,629	($112,955,478)	$88,426,464	($52,328,957)
	Surplus	($83,332,665)	($104,947,376)	$14,485,066	$5,072,985	$10,533,444	$67,512,070	
	Total	($149,035,540)	$296,196,975	$175,179,465	$27,658,614	($102,422,034)	$155,938,535	($52,328,957)
Total		($166,028,386)	$596,960,039	$456,282,380	$80,820,304	($94,973,195)	$549,669,736	$64,166,303

Revenue

Long Term FTR Auction Revenue

Table 13-30 shows the long term FTR auction revenue data by trade type, FTR direction, period type and class type. The 2019/2022 Long Term FTR Auction netted $161.7 million in revenue, $132.1 million more than the previous Long Term FTR Auction. Buyers paid $186.9 million and sellers received $25.2 million, up $134.7 million and $2.6 million over the previous Long Term FTR Auction.

Table 13-30 Long Term FTR Auction Revenue: 2019/2022

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($24,371,535)	($73,884,329)	($49,931,125)	($148,186,990)
		Year 2	($9,426,319)	($46,879,640)	($29,745,022)	($86,050,981)
		Year 3	($6,221,645)	($36,046,808)	($23,352,067)	($65,620,520)
		Year All	$0	($530,720)	($542,459)	($1,073,179)
		Total	($40,019,499)	($157,341,498)	($103,570,673)	($300,931,670)
	Prevailing Flow	Year 1	$56,342,786	$110,041,760	$65,535,011	$231,919,557
		Year 2	$35,772,980	$67,840,105	$39,064,743	$142,677,828
		Year 3	$27,836,762	$54,322,644	$30,971,170	$113,130,576
		Year All	$0	$67,125	$8,271	$75,396
		Total	$119,952,527	$232,271,635	$135,579,195	$487,803,357
	Total		$79,933,028	$74,930,136	$32,008,523	$186,871,687
Sell offers	Counter Flow	Year 1	($32,570)	($6,863,849)	($4,683,412)	($11,579,831)
		Year 2	$0	($2,736,399)	($1,873,414)	($4,609,814)
		Year 3	0	($829,854)	($365,625)	($1,195,479)
		Year All	NA	NA	NA	NA
		Total	($32,570)	($10,430,102)	($6,922,451)	($17,385,123)
	Prevailing Flow	Year 1	$647,479	$18,398,499	$9,654,110	$28,700,088
		Year 2	$0	$6,208,776	$3,401,660	$9,610,437
		Year 3	0	$3,064,644	$1,183,365	$4,248,009
		Year All	NA	NA	NA	NA
		Total	$647,479	$27,671,919	$14,239,135	$42,558,533
	Total		$614,909	$17,241,817	$7,316,683	$25,173,410
Total			$79,318,119	$57,688,319	$24,691,839	$161,698,277

Annual FTR Auction Revenue

Table 13-31 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2019/2020 planning period generated $844.6 million, up 2.7 percent from $822.6 million in the 2018/2019 planning period, and up 55.8 percent from $542.2 million in the 2017/2018 planning period. Counter flow FTR holders received $293.3 million, up 6.7 percent from the previous planning period and prevailing flow FTR holders paid $1,137.8 million, up 3.7 percent from the previous planning period.

Table 13-31 Annual FTR auction revenue: 2019/2020

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($33,941,839)	($188,817,805)	($112,719,091)	($335,478,736)
		Prevailing Flow	$151,953,708	$497,205,253	$257,220,412	$906,379,374
		Total	$118,011,869	$308,387,448	$144,501,321	$570,900,638
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,114,280	$49,556,288	$27,428,870	$78,099,438
		Total	$1,114,280	$49,556,288	$27,428,870	$78,099,438
	Total	Counter Flow	($33,941,839)	($188,817,805)	($112,719,091)	($335,478,736)
		Prevailing Flow	$153,067,988	$546,761,542	$284,649,282	$984,478,812
		Total	$119,126,149	$357,943,737	$171,930,191	$649,000,076
Self-scheduled bids	Obligations	Counter Flow	($989,199)	NA	NA	($989,199)
		Prevailing Flow	$228,400,870	NA	NA	$228,400,870
		Total	$227,411,671	NA	NA	$227,411,671
Buy and self-scheduled bids	Obligations	Counter Flow	($34,931,038)	($188,817,805)	($112,719,091)	($336,467,935)
		Prevailing Flow	$380,354,578	$497,205,253	$257,220,412	$1,134,780,244
		Total	$345,423,540	$308,387,448	$144,501,321	$798,312,309
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,114,280	$49,556,288	$27,428,870	$78,099,438
		Total	$1,114,280	$49,556,288	$27,428,870	$78,099,438
	Total	Counter Flow	($34,931,038)	($188,817,805)	($112,719,091)	($336,467,935)
		Prevailing Flow	$381,468,859	$546,761,542	$284,649,282	$1,212,879,682
		Total	$346,537,820	$357,943,737	$171,930,191	$876,411,748
Sell offers	Obligations	Counter Flow	($2,126,088)	($24,747,002)	($16,333,984)	($43,207,074)
		Prevailing Flow	$6,900,493	$44,650,824	$22,795,861	$74,347,179
		Total	$4,774,405	$19,903,822	$6,461,877	$31,140,105
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$452,889	$255,162	$708,051
		Total	$0	$452,889	$255,162	$708,051
	Total	Counter Flow	($2,126,088)	($24,747,002)	($16,333,984)	($43,207,074)
		Prevailing Flow	$6,900,493	$45,103,714	$23,051,023	$75,055,230
		Total	$4,774,405	$20,356,711	$6,717,039	$31,848,155
Total			$341,763,415	$337,587,025	$165,213,152	$844,563,592

The total net of all buy and sell offers in the Annual FTR Auction, not including self scheduled FTRs, was $393.5 million for the 2017/2018 planning period and $624.8 million for the 2018/2019 planning period, a 58.8 percent increase in revenue. The total buy bids were 488,734.1 MW for the 2017/2018 planning period and 587,775.4 MW for the 2018/2019 planning period. The revenue of FTRs per cleared MW increased from $805.14 for the 2017/2018 planning period to $1,062.99 for the 2018/2019 planning period, a 32.0 percent increase. The per MW revenue of FTRs in the 2016/2017 planning period was $1,564.83.

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTR sold in Annual FTR Auctions. Table 13-32 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2018/2019 planning periods if long term FTRs were sold at annual auction clearing prices. This difference provides a good estimate of the value of the transmission capability made available in the Long Term FTR Auction that is not made available to ARR holders. This capability should be made available to ARR holders in the Annual FTR Auction where it is the most valuable.

Table 13-32 Estimated additional Long Term FTR Auction revenue at Annual FTR Auction prices

	Long Term FTR Product				
Planning Period	YR3	YR2	YR1	YRALL	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
2018/2019	$7,872,604	$2,926,457	$13,480,353	($111,226)	$24,168,189
2019/2020	$9,711,188	$4,098,887	$103,227,004	$805,425	$117,842,504
Total	$183,879,959	$76,198,567	$98,899,981	$2,426,270	$361,404,776

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-33 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for January through May 2019. The Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period netted $59.7 million in revenue, the difference between buyers paying $324.9 million and sellers receiving $265.2 million. For the entire 2017/2018 planning period, the Monthly Balance of Planning Period FTR Auctions netted $40.3 million in revenue with buyers paying $182.0 million and sellers receiving $141.7 million.

Table 13-33 Monthly Balance of Planning Period FTR Auction revenue: 2019

Monthly			Class Type			
Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-19	Obligations	Buy bids	$7,429,663	$9,608,687	$4,887,280	$21,925,630
		Sell offers	$987,205	$6,540,062	$4,065,408	$11,592,675
	Options	Buy bids	$1,240,922	$1,030,156	$736,432	$3,007,510
		Sell offers	$14,822	$6,069,106	$3,845,740	$9,929,668
Feb-19	Obligations	Buy bids	$8,986,453	$8,637,432	$5,482,321	$23,106,206
		Sell offers	$48,475	$7,523,942	$6,034,319	$13,606,736
	Options	Buy bids	$838,173	$771,411	$729,381	$2,338,964
		Sell offers	$32,186	$5,356,597	$3,251,805	$8,640,588
Mar-19	Obligations	Buy bids	$5,815,450	$7,982,901	$3,873,158	$17,671,509
		Sell offers	$1,666,791	$5,726,644	$2,935,930	$10,329,364
	Options	Buy bids	$111,401	$903,499	$528,783	$1,543,682
		Sell offers	$11,372	$3,178,368	$1,908,681	$5,098,421
Apr-19	Obligations	Buy bids	$1,001,882	$4,982,173	$2,271,137	$8,255,192
		Sell offers	$242,252	$3,444,912	$1,632,619	$5,319,784
	Options	Buy bids	$37,128	$704,332	$362,419	$1,103,879
		Sell offers	$4,980	$1,645,001	$898,043	$2,548,024
May-19	Obligations	Buy bids	($504,881)	$3,675,925	$1,696,524	$4,867,568
		Sell offers	$449,130	$1,607,559	$672,541	$2,729,231
	Options	Buy bids	$40,292	$250,657	$130,412	$421,361
		Sell offers	$3,022	$1,417,317	$660,872	$2,081,211
2017/2018*	Obligations	Buy bids	$48,624,806	$80,725,915	$45,185,177	$174,535,897
		Sell offers	$3,856,422	$66,996,797	$39,571,417	$110,424,636
	Options	Buy bids	$888,416	$4,051,136	$2,566,754	$7,506,306
		Sell offers	$106,899	$19,516,633	$11,671,850	$31,295,383
	Net Total		$45,549,900	($1,736,379)	($3,491,336)	$40,322,185
2018/2019*	Obligations	Buy bids	$93,669,208	$132,488,450	$61,989,515	$288,147,173
		Sell offers	$11,150,630	$104,938,558	$61,964,081	$178,053,269
	Options	Buy bids	$4,501,727	$18,020,791	$14,189,999	$36,712,518
		Sell offers	$1,042,372	$54,821,585	$31,237,878	$87,101,835
	Net Total		$85,977,934	($9,250,902)	($17,022,444)	$59,704,587

* Shows Twelve Months

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. Figure 13-8 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the 2018/2019 planning period. The top 10 sinks that produced financial benefit accounted for 28.3 percent of total positive target allocations with the Western Hub accounting for 7.7 percent of all positive target allocations. The top 10 sinks that created liability accounted for 13.7 percent of total negative target allocations with PSEG Zone accounting for 1.9 percent of all negative target allocations.

Figure 13-8 Ten largest positive and negative FTR target allocations summed by sink: 2018/2019

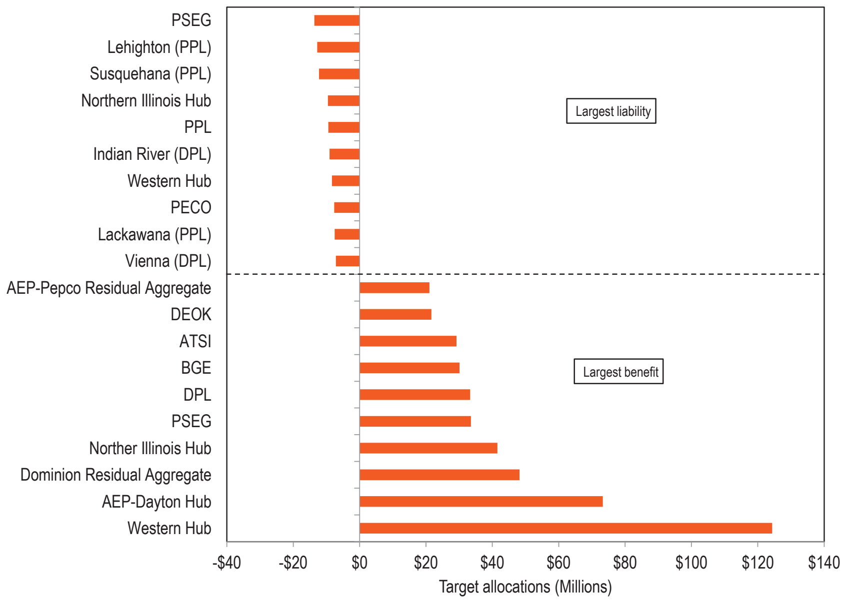
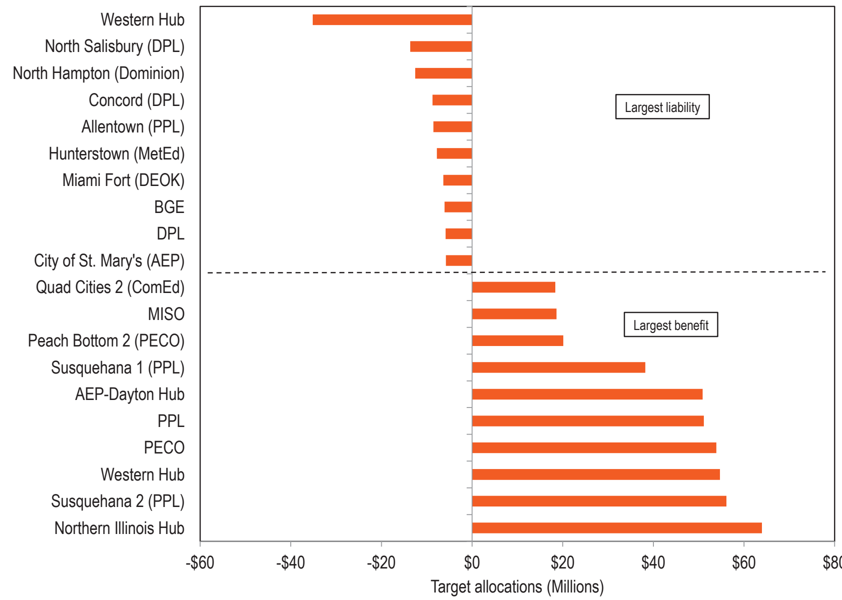


Figure 13-9 shows the 10 largest positive and negative FTR target allocations, summed by source, for the 2018/2019 planning period. The top 10 sources with a positive target allocation accounted for 26.4 percent of total positive target allocations with the Northern Illinois Hub accounting for 4.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 15.6 percent of all negative target allocations, with the Western Hub accounting for 5.0 percent.

Figure 13-9 Ten largest positive and negative FTR target allocations summed by source: 2018/2019



Revenue Adequacy

FTR revenue adequacy is not equivalent to the adequacy of ARRs/FTRs as an offset for load against total congestion. FTR revenue adequacy, under current PJM rules, is a narrower concept that compares day-ahead congestion revenue to the sum of the target allocations across the specific paths for which FTRs were purchased. A path specific target allocation is not a guarantee of payment. The adequacy of ARRs/FTRs as an offset for load against total congestion compares ARR and self scheduled FTR revenues, minus balancing congestion and M2M payments, to total congestion on the system.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead market, but also include negative FTR target allocations.[38] Total day-ahead congestion revenues in excess of FTR payments are carried

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

forward from prior months and distributed back from later months within each planning year. For example, in June 2014, $2.9 million in excess congestion revenues were carried forward to fund months later in the planning period with a revenue shortfall. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected at the end of the planning period from any FTR holders 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. Before the 2018/2019 planning period, at the end of the planning period, surplus congestion revenue, after paying any monthly shortfalls, was distributed to FTR participants in the same manner that the FTR uplift is applied. From the 2018/2019 planning period onward, at the end of the planning period, surplus congestion revenue is distributed to ARR holders prorata based on their target allocations, after making FTRs revenue adequate, and the FTR uplift continues to be applied to FTR holders. This distribution is an effort to return the congestion to load that is not available to them throughout the planning period. This method does not go far enough in that the long term auction continues to remove capacity that should be available to ARR holders, and that the terms of this distribution do not ensure ARR holders receive all of the surplus revenue.

FTR Revenue Adequacy and Stage 1B/Stage 2 ARR Allocations

A high level of revenue adequacy was primarily a result of PJM's subjective decision to reduce available system capability in FTR auctions for the 2014/2015 through 2016/2017 planning periods. PJM's decision to reduce available system capability was intended to guarantee that FTR target allocations were, on an annual basis, less than congestion. As congestion revenues are unrelated to PJM's decisions about the FTR auction model, the fewer FTRs sold, the higher the probability that congestion would exceed the sum of the FTR target allocations. PJM's decisions included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. Following the assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. The direct assignment of negative balancing congestion to load increased the congestion revenue available to pay FTR holders.

Surplus Congestion Revenue

Beginning in the 2018/2019 planning period, surplus congestion revenue, including surplus FTR auction revenue, will be distributed to ARR holders in proportion to their ARR target allocations.[39] Surplus FTR auction revenue is the difference between ARR target allocations and the sum of FTR auction revenues. PJM initiated this change to surplus congestion revenue to recognize that any surplus revenue is a result of unallocated system capability that belongs to ARR holders, not FTR holders, who had received this surplus revenue after the creation of ARRs.

Under the new allocation process, at the end of the planning period, any surplus congestion revenue will first go to ARR holders until they are revenue adequate relative to their target allocations if they are not already. The remaining surplus congestion revenue is then applied to cover FTR target allocations, if they are not already. Then at the end of the planning period, any remaining surplus congestion revenue after funding ARRs and FTRs to 100 percent, will go to ARR holders in proportion to their target allocations. While the new allocation process returns the value of some of the unallocated

39 163 FERC ¶61,165 (2018).

rights to ARR holders, it does not fully recognize that ARR holders own the rights to all congestion revenues.

Figure 13-10 shows the total monthly ARR auction revenue surplus, and its distribution to ARR and FTR holders within a month. Surplus auction revenue is first paid to FTR holders, to meet revenue adequacy for the month. In any month that is not revenue adequate from day-ahead congestion, the surplus auction revenue is used to meet revenue adequacy for FTRs. In months that are revenue inadequate even after the allocation of surplus auction revenue of that month, any remaining inadequacy is funded from surplus revenue from previous or future months within the planning period. At the end of the planning period, any remaining surplus auction revenue is distributed, prorata, to ARR holders along with other surplus transmission congestion charges.

The market rules should recognize that ARR holders have the right to all auction revenue, not just the surplus after funding FTRs. The MMU recommends that all FTR auction revenue be distributed directly to ARR holders on a monthly basis. In Figure 13-10 this would mean that the full bars would be assigned to ARR holders in every month.

Figure 13-10 Monthly surplus ARR revenue to ARR and FTR holders: 2017/2018 through 2018/2019

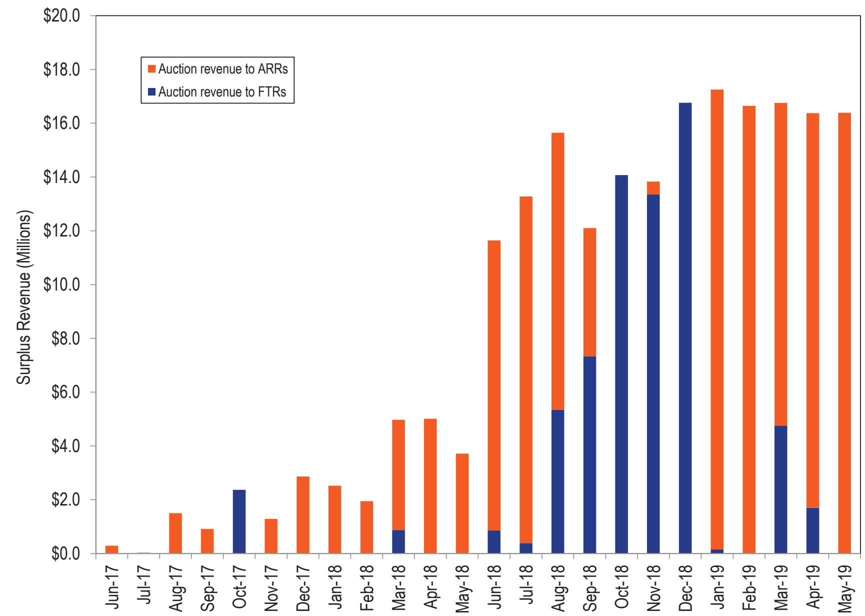


Figure 13-11 shows the monthly auction revenue collected each month from FTR auctions above ARR target allocations from the 2011/2012 through 2018/2019 planning periods.

Beginning with the 2014/2015 planning period, market rules allow PJM to decrease prevailing flow target allocations by clearing counter flow FTRs using FTR auction revenue, without making the opposite prevailing flow FTR available, as long as ARRs remain revenue adequate.[40] The result is to increase FTR funding, but to decrease ARR revenue.

FTR auction revenue is the value that FTR buyers assign to congestion rights that ARR holders are selling. The subsequent assignment of any part of that auction revenue back to the buyers is providing an unsupported rebate.

40 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

Auction revenue collected should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders.

Figure 13-11 Monthly surplus ARR revenue: 2011/2012 through 2018/2019

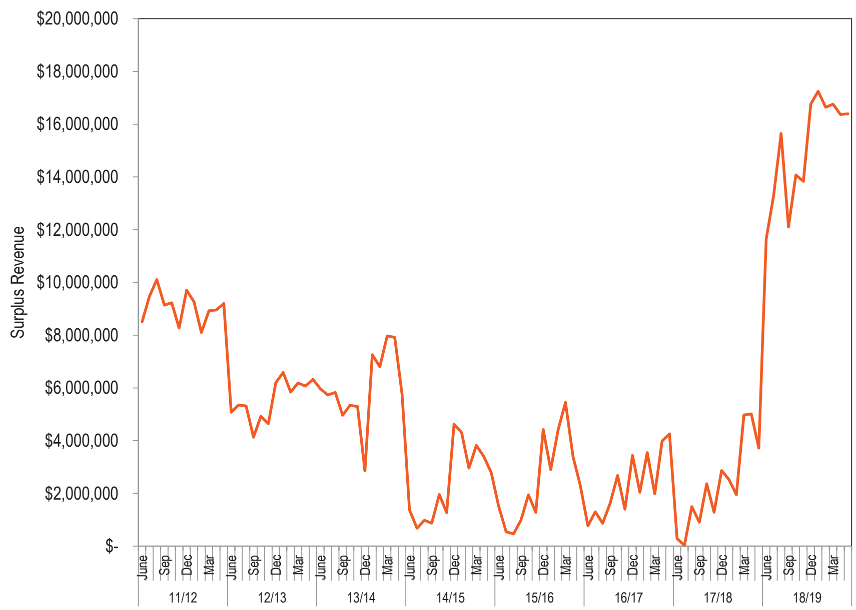


Table 13-34 shows the auction revenue over ARR target allocations, by planning period, for planning periods 2010/2011 through 2018/2019.

Table 13-34 Additional Auction Revenue: 2010/2011 through 2018/2019

Planning Period	Excess Auction Revenue
2010/2011	$29,704,562
2011/2012	$108,874,342
2012/2013	$66,652,822
2013/2014	$71,687,937
2014/2015*	$29,045,590
2015/2016	$29,612,591
2016/2017	$27,917,175
2017/2018	$27,419,061
2018/2019	$180,757,676
Total	$571,671,756

*Start of counter flow "buy back"

ARR and FTR Revenue Adequacy

Revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower and less relevant 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. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load.

Total net FTR auction revenue for the 2017/2018 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $573.8 million. The FTR auction revenue collected pays ARR holders' credits. During the 2018/2019 planning period, total net FTR auction revenue was $907.6 million.

Table 13-35 lists projected ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions for the 2017/2018 planning period and 2018/2019 planning periods. FTRs were paid at 100 percent of the target allocation level for the 2014/2015, 2015/2016 and 2016/2017 planning periods. PJM collected $1,457.1 million, $1,003.3 million and $828.7 million of FTR revenues during the 2014/2015, 2015/2016 and the 2016/2017 planning periods. 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.

This step change to high levels of FTR revenue adequacy beginning in the 2014/2015 planning period was primarily a result of subjective interventions by PJM to address prior low levels of revenue adequacy.

Table 13-35 presents the PJM FTR revenue detail for the 2017/2018 planning period the 2018/2019 planning period. In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion. For the 2017/2018 planning period there was $0.5 million and $0.7 million in negative day-ahead congestion in October and November 2017 for a total of $1.2 million in negative day-ahead congestion charged to FTR holders.

Table 13-35 Total annual PJM ARR and FTR revenue detail (Dollars (Millions)): 2017/2018 and 2018/2019

Accounting Element	2017/2018	2018/2019
ARR information		
ARR target allocations	$573.8	$726.8
ARR credits	$573.8	$726.8
FTR auction revenue	$601.2	$907.6
Annual FTR Auction net revenue	$542.2	$822.6
Long Term FTR Auction net revenue	$18.6	$25.2
Monthly Balance of Planning Period FTR Auction net revenue	$40.3	$59.7
Surplus auction revenue		
ARR excess	$27.4	$180.8
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$1,396.2	$1,137.6
Negative target allocations	($411.2)	($234.2)
FTR target allocations	$985.0	$903.3
Adjustments:		
Adjustments to FTR target allocations	($6.2)	($2.1)
Total FTR targets	$978.8	$901.2
FTR payout ratio	100%	100%
FTR revenues		
ARR excess	$27.4	$180.8
Congestion		
Net Negative Congestion (enter as negative)	($1.2)	$0.0
Hourly congestion revenue	$1,323.3	$832.7
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($6.3)	$0.0
Adjustments:		
Excess revenues carried forward into future months	$15.7	$6.5
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Excess revenues distributed to other months	$15.7	$6.5
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,365.0	$1,020.0
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,365.0	$914.3
Remaining deficiency	($370.5)	($112.3)

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for FTR paths and are defined to be the revenue required to compensate FTR holders for the day-ahead CLMP difference on those paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-36 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 13-36 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. October 2017 had revenue shortfalls totaling $15.6 million, but was fully funded using excess revenue from previous months.

Table 13-36 Monthly FTR accounting summary (Dollars (Millions)): 2017/2018 and 2018/2019

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus/Deficiency (with adjustments)
Jun-17	$64.8	$60.1	100.0%	$64.8	100.0%	($4.7)
Jul-17	$51.8	$45.4	100.0%	$51.8	100.0%	($6.3)
Aug-17	$35.7	$31.0	100.0%	$35.7	100.0%	($4.7)
Sep-17	$100.5	$93.0	100.0%	$100.5	100.0%	($7.5)
Oct-17	$53.2	$68.8	77.2%	$68.8	100.0%	$15.7
Nov-17	$61.2	$51.0	100.0%	$61.2	100.0%	($10.1)
Dec-17	$142.7	$81.4	100.0%	$142.7	100.0%	($61.3)
Jan-18	$520.2	$268.1	100.0%	$520.2	100.0%	($252.1)
Feb-18	$45.8	$36.1	100.0%	$45.8	100.0%	($9.6)
Mar-18	$85.2	$81.1	100.0%	$85.2	100.0%	($4.1)
Apr-18	$62.4	$55.6	100.0%	$62.4	100.0%	($6.9)
May-18	$125.9	$108.8	100.0%	$125.9	100.0%	($17.1)
Summary for Planning Period 2017/2018						
Total	$1,349.3	$980.5		$1,365.0		($368.8)
Jun-18	$106.8	$96.0	100.0%	$106.8	100.0%	($10.8)
Jul-18	$84.1	$71.3	100.0%	$84.1	100.0%	($12.9)
Aug-18	$84.8	$74.6	100.0%	$84.8	100.0%	($10.3)
Sep-18	$107.3	$102.8	100.0%	$107.3	100.0%	($4.8)
Oct-18	$109.1	$113.8	95.9%	$113.8	100.0%	$4.7
Nov-18	$83.0	$82.5	100.0%	$83.0	100.0%	($0.5)
Dec-18	$79.8	$81.9	97.5%	$81.9	100.0%	$1.8
Jan-19	$138.0	$120.9	100.0%	$138.0	100.0%	($17.1)
Feb-19	$53.1	$34.8	100.0%	$53.1	100.0%	($18.3)
Mar-19	$61.8	$49.8	100.0%	$61.8	100.0%	($12.3)
Apr-19	$41.8	$27.1	100.0%	$41.8	100.0%	($14.8)
May-19	$63.9	$47.0	100.0%	$63.9	100.0%	($17.0)
Summary for Planning Period 2018/2019						
Total	$1,013.5	$902.5		$1,020.2		($112.3)

Figure 13-12 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through May 2019. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-12 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. If there are surplus congestion revenues in a given month, the surplus is distributed to other months within the planning period that were revenue deficient. The payout ratio for revenue inadequate months in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period. March 2015 had high levels of negative balancing congestion that resulted in a payout ratio of 64.6 percent. However, there was enough surplus from previous months to bring the payout ratio to 100 percent. Congestion in December 2017 and January 2018 was high relative to other months in the planning period, resulting in an extremely high payout ratio.

Figure 13-12 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through May 2019

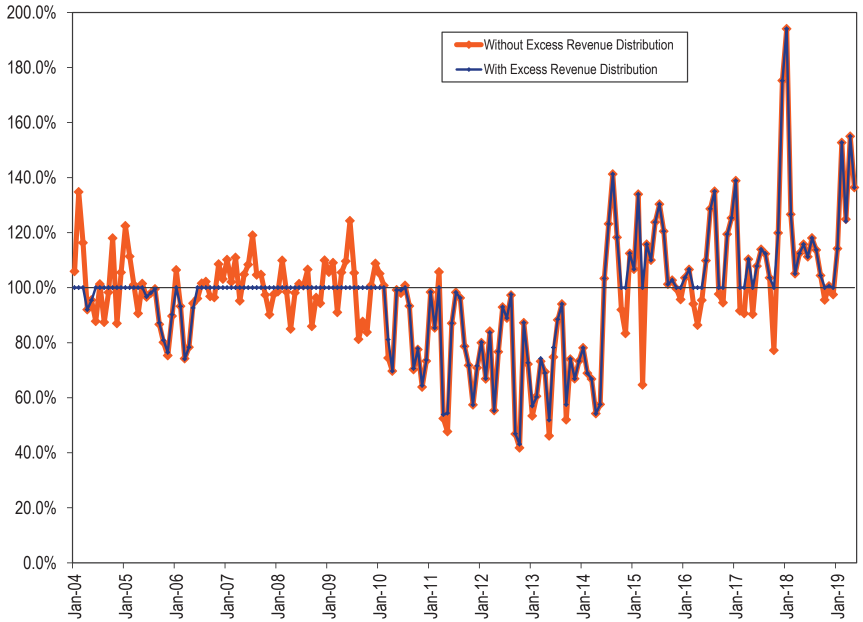


Table 13-37 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was surplus congestion revenue to pay FTR holders pro rata in proportion to their net positive target allocations, resulting in a payout ratio of 116.2 percent, 106.8 and 113.1 percent for the planning periods.

Table 13-37 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%
2014/2015	100.0%
2015/2016	100.0%
2016/2017	100.0%
2017/2018	100.0%
2018/2019	100.0%

FTR Uplift Charge

At the end of the planning period, an uplift charge may be assigned to FTR holders. This charge is to cover the net of the monthly deficiencies, if any, in the target allocations calculated for individual participants. An individual participant's uplift charge is a ratio of their share of net positive target allocations to the total net positive target allocations.

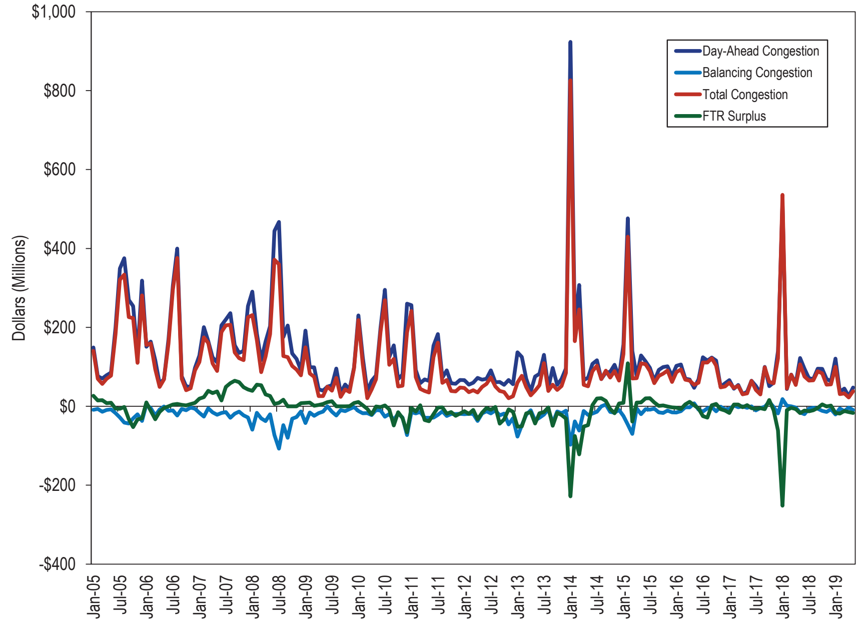
Revenue Adequacy Issues and Solutions

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues. The reasons include unavoidable modeling differences, such as emergency outages, avoidable modeling differences, such as outage modeling decisions, cross subsidies among and between FTR participants ARR holders, the use of generation to load paths rather than a measure of total congestion, and the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction.

The issuance of the September 15, 2016, FERC order increased the gap between congestion revenue and ARR/FTR revenue collected. The result of allocating balancing congestion and M2M payments to ARRs, and allocating surplus congestion revenue, which contains excess day-ahead congestion revenue and additional FTR auction revenue, to FTR holders solely, increased revenue to FTRs and reduced payments to load. Under the new rules, effective for the 2018/2019 planning period, ARR holders receive the surplus congestion revenue, but must still pay balancing congestion to help FTR holders' revenue adequacy. FTR portfolio netting leads to cross subsidies among FTR participants which treat FTRs differently depending on how a participant's portfolio in constructed. Restructuring Stage 1A allocations using QRRs for retired resources is an attempt to fix a flawed system, but retains the core problem which is reliance on generation to load contract path congestion revenue rights rather than on the correct definition of congestion revenues. The rule change does not address the problem with using contract paths, does not address the deficiencies for active units and gives priority to units based on financial, not physical, determinations. The purpose of the FTR/ARR system is to return congestion revenue to load. The current and newly modified rules do not meet this goal.[41]

Figure 13-13 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through May 2019. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

Figure 13-13 FTR surplus and the collected day-ahead, balancing and total congestion: January 2005 through May 2019



41 *2018 State of the Market Report for PJM*, Vol. 2, Section 13: FTRs and ARRs.

ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs and later ARRs were intended to return congestion revenues to load. With the implementation of the current FTR/ARR design, the purpose of FTRs has been subverted.

FERC Order on FTRs: Balancing Congestion and M2M Payment Allocation

On September 15, 2016, FERC issued an order removing balancing congestion and market to market (M2M) payments from the FTR funding equation and assigned them, on a load ratio basis, to load and exports.[42] The MMU petitioned the U.S. Court of Appeals for the District of Columbia Circuit to reverse the order and restore the longstanding approach to calculating congestion revenues. The case was consolidated with appeals filed by others. The consolidated appeals were denied in an unpublished opinion issued June 12, 2018.[43]

The new rule for calculating congestion revenues went into effect on June 1, 2017, for the 2017/2018 planning period.

In its compliance filing PJM redefined balancing congestion as balancing congestion plus market to market (M2M) payments between MISO and NYISO. Under the order, load and exports will pay balancing congestion and M2M payments proportionally. Based on the 2011/2012 and subsequent planning periods, total balancing congestion and M2M payments were $1,607.4 million, so load would have been responsible for an additional $1,103.3 million in balancing congestion and M2M charges if the new rules had been place for that period.

In addition, FERC ordered that all day-ahead congestion revenue in excess of FTR target allocations and additional FTR auction revenue over ARR target allocations, belongs to FTR holders. This further increased the underlying problem with the FTR design and reduced the probability that congestion revenues will be returned to load.

42 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

43 *NJBPU v. FERC*, No. 17-1106 et al., attached memorandum at 3 ("After a thorough review of the record, we conclude that none of petitioners' challenges can overcome the deference we owe FERC. As FERC's order make clear, the Commission adequately considered and reasonably rejected each of the arguments that petitioners advance before the court.")

Before the 2018/2019 planning period, the reallocation of balancing congestion and M2M payments from FTR holders to load, and the allocation of additional FTR auction revenues to FTR holders required ARRs to subsidize FTRs.

Beginning with the 2018/2019 planning period, surplus congestion revenue, which is defined as day-ahead congestion revenue and surplus auction revenue remaining after funding FTRs, will be allocated to ARRs prorata based on ARR target allocations.[44]

This surplus revenue is generated by a failure of the current ARR/FTR construct to make all congestion revenue rights available to load in the form of ARRs. All congestion revenue belongs to ARR holders and PJM's new surplus congestion allocation rule is an attempt to get closer to that goal. However, under the current rules, ARR holders will only have access to this surplus after full funding of FTRs is accomplished, which does not fully recognize ARR holders' primary rights to this surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 percent.

Table 13-39 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. Offsets outlined in red are the actual offsets based on the effective rules in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total congestion and the load share of balancing and M2M payments. The 100 percent payout ratio in the 2016/2017 planning period, which was the last planning period before balancing congestion was assigned to load, is likely due to PJM selecting an overly conservative ARR/FTR model to improve FTR revenue adequacy. The 2017/2018 offset is the sum of the ARR credits, adjusted FTR credits and the load share of balancing congestion and M2M payments. The post 2017/2018 offset is calculated identically to the 2017/2018 offset, but includes any surplus congestion revenue remaining in the planning period. FTRs are fully funded before ARR holders have access to the surplus, so in planning periods with revenue

44 163 FERC ¶61,165 (2018).

inadequacy there is no difference between 2017/2018 and post 2017/2018. In planning periods that are fully funded, the surplus goes to load, and provides an increased congestion offset.

The allocation of balancing congestion and M2M payments to load went into effect in the 2017/2018 planning period. If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,305.1 million less in congestion offsets from the 2011/2012 through the 2018/2019 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been $1,427.4 million. The actual underpayment to load in the 2017/2018 planning period was $306.1 million with a $370.7 million overpayment to FTR holders. For the 2018/2019 planning period the underpayment to load in the same period would have been $85.9 million.

Allocating surplus congestion revenue to load rather than FTRs in the 2018/2019 planning period would change the total congestion offset for load to 92.1 percent from 78.1 percent under the rules that allocated balancing congestion to load, or 99.4 percent under the old rules which include balancing in total congestion but assigned all surplus to FTR holders.

Table 13-38 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2018/2019

	Revenue				Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Total Congestion	Excess Revenue	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	$512.2	$249.8	$749.7	($192.5)	$762.0	100.0%	$598.6	79.8%	$563.0	79.8%
2012/2013	$349.5	$181.9	$524.8	($292.3)	$531.4	100.0%	$275.9	52.6%	$257.5	52.6%
2013/2014	$337.7	$456.4	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$623.1	30.7%
2014/2015	$482.4	$404.4	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$715.0	52.7%
2015/2016	$635.3	$223.4	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$745.2	78.4%
2016/2017	$640.0	$169.1	$780.8	$72.6	$809.1	100.0%	$727.7	93.2%	$763.8	97.8%
2017/2018	$427.3	$294.2	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$886.5	74.3%
2018/2019	$529.1	$130.1	$680.0	$112.3	$675.93	99.4%	$530.8	78.1%	$626.3	92.1%
Total	$3,913.6	$2,109.2	$8,107.3	($425.4)	$6,039.5	74.5%	$4,734.4	58.4%	$5,180.5	63.9%

Table 13-39 demonstrates the inadequacies of the ARR/FTR design. The goal of the design should be to return 100 percent of the congestion revenues to the load. The actual results continue to fall well short of that goal.

Zonal ARR Congestion Offset

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on pre 1999 paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other Stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load.

Table 13-39 shows the congestion offsets paid to load: the allocation of ARR revenue; self scheduled FTR revenue; and the allocation of end of planning year surplus. Table 13-39 also shows payments by load: the allocation of balancing congestion; the allocation of M2M payments. The total offset available to load, which is the revenue load receives to offset their congestion charges, is the sum of all of those credits and charges.

Table 13-39 shows day-ahead congestion and balancing congestion paid by load in each zone, plus the allocation of M2M charges.[45]

The zonal offset percentage shown in Table 13-39 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone, including M2M payments.

45 See *2018 State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-39 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2018/2019 planning period

Zone	ARR Credits	FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
AECO	$4.9	$0.0	($1.9)	$0.8	$3.8	$11.9	($1.5)	($0.4)	$10.0	37.8%
AEP	$56.8	$38.9	($23.7)	$21.8	$93.8	$129.6	($18.9)	($5.1)	$105.7	88.7%
APS	$40.8	$10.4	($9.2)	$8.9	$50.9	$53.7	($6.9)	($2.0)	$44.8	113.6%
ATSI	$43.3	$0.3	($12.4)	$6.7	$37.9	$64.8	($9.7)	($2.6)	$52.5	72.3%
BGE	$67.2	$1.5	($5.8)	$10.7	$73.6	$26.1	($4.8)	($1.2)	$20.0	367.3%
ComEd	$91.7	$10.2	($17.8)	$17.3	$101.3	$113.0	($12.7)	($3.8)	$96.5	105.0%
DAY	$7.2	$0.5	($3.2)	$1.1	$5.5	$16.1	($2.6)	($0.7)	$12.8	42.8%
DEOK	$41.5	$9.1	($5.0)	$7.7	$53.4	$28.9	($4.1)	($1.1)	$23.7	225.5%
DLCO	$9.1	$0.0	($2.5)	$1.4	$8.0	$10.2	($1.9)	($0.5)	$7.7	104.2%
Dominion	$7.1	$44.3	($18.7)	$9.4	$42.3	$84.4	($14.2)	($4.0)	$66.2	63.9%
DPL	$39.3	$8.2	($3.4)	$7.0	$51.0	$63.0	($3.3)	($0.7)	$59.0	86.5%
EKPC	$0.0	$0.0	($2.4)	$0.0	($2.3)	$11.8	($1.7)	($0.5)	$9.5	(24.1%)
EXT	$3.4	$0.0	$0.0	$0.5	$3.9	$0.7	($4.8)	$0.0	($4.1)	(95.8%)
JCPL	$2.5	$0.0	($4.2)	$0.4	($1.3)	$24.6	($3.3)	($0.9)	$20.4	(6.2%)
Met-Ed	$7.9	$0.4	($2.9)	$1.3	$6.6	$17.9	($2.6)	($0.6)	$14.6	45.2%
PECO	$21.2	$0.2	($7.5)	$3.3	$17.2	$37.3	($5.7)	($1.6)	$30.0	57.3%
Penelec	$10.9	$4.0	($3.2)	$2.0	$13.7	$21.7	($3.4)	($0.7)	$17.6	77.7%
Pepco	$28.9	$2.0	($5.5)	$5.0	$30.3	$23.6	($4.2)	($1.2)	$18.2	166.3%
PPL	$4.4	$0.0	($7.6)	$0.7	($2.4)	$44.2	($5.9)	($1.6)	$36.7	(6.7%)
PSEG	$40.9	$0.0	($8.1)	$6.3	$39.2	$47.3	($7.0)	($1.7)	$38.6	101.5%
RECO	$0.1	$0.0	($0.3)	$0.0	($0.2)	$2.0	($0.9)	($0.1)	$1.1	(19.0%)
Total	$529.0	$130.1	($145.2)	$112.3	$626.2	$832.7	($120.0)	($31.1)	$681.6	91.9%

The total congestion offset paid to loads was 91.9 percent of congestion costs.[46] The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like JCPL, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions. Loads in some zones, like EKPC, receive negative offsets as a result of balancing and M2M charges. The EXT zone is a set of external interfaces (MISO, DUKEXP and CPLEEXP) that are allocated ARRs (the allocated ARRs sink at the external interface) based on agreements with PJM. There is no PJM billable load associated with these ARR positions. EXT is paid ARR credits based on ARR assignments, but the offsets are less than the negative balancing congestion allocated to EXT.

The results shown in Table 13-39 further illustrate the fundamental issues with the FTR/ARR construct in PJM. If ARRs were assigned correctly, based on actual zonal congestion, and if balancing congestion were appropriately included in total congestion, the zonal offsets to load should equal zonal congestion payments by load.

Credit

There were no collateral defaults in 2019. There were 58 payment defaults in 2019 not involving GreenHat Energy, LLC for a total of $59,933. GreenHat Energy continued to accrue payment defaults of $$39.1 million in the first six months of 2019 for a total of $116.1 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.

Modified Credit Requirements

PJM modified its credit requirements based on the GreenHat Energy default.

On December 11, 2017, PJM filed, and FERC accepted, a modification to the credit rules for Long Term FTR Auctions.[47] Credit requirements are based on a calculation of the expected FTR values relative to the price of FTRs. Under the prior rules, PJM calculated the expected FTR value based on a three year weighted average of nodal prices. The method was based solely on historical data, and did not account for transmission upgrades that could affect congestion and therefore FTR values. Under the new rules, PJM calculates the FTR credit requirement using the higher of: the expected FTR value based on a three year weighted average of the previous three year's nodal prices; and the expected FTR value based on a planning model simulation of expected

46 The 91.9 offset result is not identical to the 92.1 included in this section as a result of rounding and the use of congestion data at a different temporal granularity.

47 See Docket No. ER18-425.

congestion over the next year incorporating transmission upgrades (the adjusted historical value).

The new approach to calculating the expected value of FTRs is only used for one year, including the YR1 long term FTR. PJM's modeling change does not address the same sources of credit risk for YR2 and YR3 of LTFTRs. PJM continues to use the old method of calculating expected FTR values for YR2 and Y3 of LTFTRs.

On July 27, 2018, PJM filed, and FERC accepted, a modification to the credit rules for the FTR Market that adds a volumetric credit requirement of $0.10 per MWh on participants' FTR portfolios.[48]

On January 31, 2019, PJM filed a modification to the credit rules that would allow PJM to update the credit requirements for already acquired FTRs.[49] PJM terms this proposal mark to auction. Under the current rules PJM cannot issue a collateral call within an FTR's effective period. Under the proposed mark to auction rules PJM could calculate the credit requirement based on the most recent auction price and make any required collateral calls.

PJM's proposed credit policy incorporates all of these changes. The final credit requirement is the higher of the historical weighted value, the adjusted historical weighted value, the volumetric requirement or the mark to auction requirement. If, during the planning period, the mark to auction requirement is higher than the current credit requirement, the mark to auction credit requirement is adopted.

GreenHat Energy, LLC Default

On June 21, 2018, GreenHat Energy, LLC was declared in payment default for non-payment of a $1.2 million weekly invoice on June 5, 2018. GreenHat had been declared in default twice earlier in June 2018 for two collateral calls totaling $2.8 million.[50]

GreenHat held a large FTR position which, according to the tariff provisions effective in June 2018, must be liquidated in the FTR auctions closest to the effective dates of the positions held.[51] The net gain or loss on these liquidated positions is added to the payment default amount that will then be allocated to PJM members according to OA sections 15.1.2A(1) and 15.2.2.

GreenHat's FTR initial portfolio was primarily long term FTRs, many of which were counterflow, although GreenHat subsequently purchased annual FTRs to offset their credit requirements. Liquidation of the counterflow positions through an auction would require payment to the acquiring party an amount equal to the expected value of the counterflow FTR position, plus a risk premium plus a profit. Given the size of GreenHat's portfolio, liquidation was expected to have a significant effect on FTR market prices in any months where liquidation occurred and result in significant payments by PJM members.

On July 26, 2018, PJM filed a request with FERC for a waiver of the tariff provision requiring immediate liquidation of a defaulted FTR position.[52]

Between the default date and the filing of the waiver, one monthly FTR auction occurred for August 2018. In this auction, PJM was required, by existing tariff provisions, to liquidate GreenHat's prompt month FTR positions. The result of this liquidation of prompt month August FTRs was $24.1 million in costs charged to the default allocation assessment.

Consistent with the waiver request, in September 2018, Members elected to settle GreenHat's FTR portfolio at the time the FTRs are due, rather than liquidate them, so default allocation assessment charges would continue to accrue on GreenHat's defaulted FTR portfolio through May 2021.

On August 23, 2019 PJM filed, and FERC accepted, effective August 24, 2018, a tariff revision that replaces the rule requiring immediate liquidation.[53] Under the new rule FTRs within a defaulted participant's portfolio will settle, as do all FTRs, at the hourly day-ahead value. Any positive or negative target allocations will then be credited or charged to the default allocation assessment. The

48 164 FERC ¶ 61,215 (2018).
49 *See* "PJM Interconnection, LLC Revisions to PJM Tariff to Incorporate FTR Mark-to-Auction Provisions," Docket No. ER19-945 (January 31, 2019).
50 Daugherty, Suzanne, email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).
51 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).
52 See 166 FERC ¶ 61,072, *reh'g pending*.
53 See Letter Order, FERC Docket No. ER18-2289-000 (October 19, 2018).

default allocation assessment is charged to all PJM participants in proportion to their gross bill as the assessment is calculated monthly for the duration of the defaulted positions. The final amount of payments is not known until the end of the term of all the defaulted FTRs.

On January 30, 2019, FERC denied PJM's request for a waiver regarding the liquidation of FTRs in the July 2018 Balance of Planning Period FTR Auction and the preceding month's non-liquidation of FTRs. In the waiver denial, FERC ordered PJM to take "steps that are necessary to comply with the effective Tariff language when the July 2018 auction was conducted and by unwinding settlements made for the September, October, November, December and January positions that should have been liquidated."[54] PJM has estimated that market participants could be required to pay $250 to $300 million to resolve GreenHat's defaulted FTRs.[55]

On February 21, 2019 PJM filed a motion to stay FERC's waiver denial, and on February 26, 2019 PJM filed a request for rehearing or clarification on the waiver denial.[56] [57] On March 26, 2019 FERC granted PJM's request for rehearing.[58] On June 5, 2019, FERC issued an order established a paper hearing and settlement judge procedures regarding the GreenHat liquidation waiver request. FERC recognized "...there are multiple complexities associated with implementing the Waiver Order Directive that should be addressed in a paper hearing..."[59] Before the paper hearing begins, FERC established a settlement procedure to "...encourage the parties to make every effort to settle their disputes before the paper hearing commences."[60]

As an alternative to the PJM proposal, the MMU recommended the cancellation of defaulted FTRs, which would have a fixed impact within the FTR market alone, and would not have extended the potential impacts past the current planning period.

54 *See* 166 FERC ¶ 61,072 P35, *reh'g pending.*
55 *See* Presentation. "Update on FERC Order Denying PJM's Request for Waiver re: Liquidating FTR Positions of Defaulted Member," MRC. February 21, 2019.
56 *See* "Motion of PJM Interconnection, LLC for Stay," Docket No. 18-2068 (February 21, 2019).
57 *See* "Request of PJM Interconnection LLC for Rehearing or, in the Alternative, Motion for Clarification of Commission Order," Docket No. 18-2069 (February 26, 2019).
58 *See* "Order Granting Rehearings for Further Consideration," Docket No. ER18-2016-001 (March 26, 2019).
59 *See* "Order Establishing Paper Hearing and Settlement Judge Procedures," Docket No. ER18-2068 (June 5, 2019), P27.
60 *See* "Order Establishing Paper Hearing and Settlement Judge Procedures," Docket No. ER18-2068 (June 5, 2019), P28.

GreenHat Energy Default Lessons Learned

On August 14, 2018, PJM hosted an FTR risk management workshop whose participants included experts in energy market and risk management in addition to PJM and the MMU.[61] The objective of this workshop was to examine the credit policies of the FTR market and develop suggestions for enhancements in light of the GreenHat default.

The recommendations of members of the group directly related to credit issues included: increased participation requirements; PJM discretion to make collateral calls; position limits; creation of a liquidity margin in credit requirements; limitations on credit netting for prevailing flow and counter flow positions; volatility adder to credit requirements; transfer risk management to an external authority.

The recommendations of members of the group related to relevant market design issues included: eliminate long term FTRs; revise the eligible FTR bidding points; remove at risk generators from the FTR model; and hold more frequent FTR auctions.

Bilateral Indemnification Provisions

The purchaser of an FTR in an auction may sell the FTR to a third party buyer in a bilateral transaction. PJM's credit rules included a bilateral indemnification provision that requires the seller of the FTR to pay any charges if the buyer defaults. PJM interprets the indemnification provision to make the seller solely responsible for only the charges on the FTR without receiving any of the associated credits. For example, even if the portfolio of FTRs held by the buyer is net positive, the seller must still pay all charges associated with those FTRs.[62]

By failing to net the indemnification obligation within the full portfolio of FTRs sold in a bilateral transaction, PJM's current interpretation of the rule goes beyond having the seller indemnify PJM against losses associated with a bilateral trade with the defaulting buyer. PJM's interpretation of the

61 *See* "PJM Financial Transmission Right (FTR) Risk Management Workshop," Credit Subcommittee, September 17, 2018.
62 For a more complete discussion, see: "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER19-24 (November 27, 2018).

indemnification rule requires that the seller pay any charges associated with the bilateral FTRs, regardless of the net value of the portfolio of bilateral FTRs. Even if the value of the portfolio of bilateral FTRs is net positive, the seller still pays any charges associated with any individual FTRs in that portfolio. This means that PJM is requiring the seller to indemnify PJM against charges over and above those incurred by the relevant bilaterally traded FTRs.

Under this interpretation, bilateral sellers are held to stricter credit rules than other holders of FTRs because they must guarantee more than the net amount of FTR credits for that portfolio. The requirements and obligations associated with selling an FTR should be the same regardless of how the FTR was sold.

PJM must approve every bilateral transaction. There is no reason a bilateral sale should be held to different standards than a sale within an FTR auction. If the implemented credit rules are sufficient there is no need for an indemnification provision. If the credit rules are not sufficient to protect participants from bilateral transfer risk, then bilateral transactions should be eliminated.

The indemnification rule should be modified so that the indemnifying seller was responsible for the net charges associated with the FTRs it sold to a buyer and this would still eliminate socialized default charges associated with the bilateral arrangement between the seller and the buyer. PJM's proposal to allow the indemnifying seller a onetime option to assume ownership of the negative bilateral FTRs could be modified to allow the seller to acquire all the FTRs the seller sold to the defaulting buyer. With this modification, no snap shot determination of the relative value of the FTRs is needed. In terms of socialized costs to the membership, this change in the rules and proposal would eliminate the inconsistency in the indemnification by bilateral and auction transactions.

Report of the Independent Consultants on the GreenHat Default

As a result of the GreenHat Energy default, the Board commissioned an independent group of experts to examine the default event and provide suggestions for future improvements.[63] The independent consultants examined PJM's FTR credit rules and the events that led to the GreenHat default and developed a list of causes of the GreenHat default event and solutions to help prevent such an event in the future.

The report stated four main causes of the default event:[64]

1. PJM did not have staff with the necessary training and credentials to successfully manage the financial risks posed by the numerous participants in its FTR markets. For a number of years prior to GreenHat, PJM's FTR market participants self-regulated their conduct, and the market ran smoothly. GreenHat, however, provided a set of conditions for which the framework that PJM developed over time to manage risk was inadequate.

2. PJM made a decision not to terminate GreenHat's trading rights when PJM initially understood the potential for a default. Instead PJM chose to manage the situation, which PJM believed could not get worse. As is discussed in detail in this report, PJM did not effectively manage the situation, which grew materially worse.

3. PJM personnel were naive about GreenHat's assurances of creditworthiness and a future revenue stream pledged to PJM. What is more, they did not appreciate GreenHat's determined ability to increase its position, and incur additional risk, thus expanding its losses well beyond anything PJM imagined could happen. PJM mistakenly believed it would contain and control GreenHat's behavior and risk, which in the end it did not. If PJM were better prepared to monitor market participant behavior, and better measure risk, we believe it could have and would have responded more effectively to GreenHat's empty assurances.

63 PJM. "*Report of the Independent Consultants on the GreenHat Default*," March 18, 2019 <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.
64 PJM. "*Report of the Independent Consultants on the GreenHat Default*," P7. March 18, 2019 <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.

4. PJM was late to recognize GreenHat as a problem. Had PJM declared a default upon first recognizing the GreenHat problem, the amount of the loss would have been substantial but far less than what PJM must deal with today. In any case, we find that even if PJM had made such a default declaration, our recommendations would stand as set forth in this document.

Based on these findings, the independent committee made seven recommendations including: incorporating credit/collateral best practices; clarify PJM's role as risk manager in its financial markets; build customer awareness of PJM's role in FTR market; improve analysis of participant risks; establish a Chief Risk Officer reporting to a new committee of the PJM Board of Managers; increase the frequency of Long Term Auctions; and make critical organizational changes to address financial risk management.[65]

PJM has created a stakeholder process at the MRC level to discuss improvements that address the recommendations.[66]

FTR Forfeitures

Hourly FTR Cost

Only the profit is forfeited when an FTR triggers the FTR forfeiture rule. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Under the current rules, the hourly cost is calculated incorrectly. Currently, the daily cost of an FTR is calculated for its effective period, and then divided by 24 hours. However, this does not accurately represent the hourly cost of on and off peak FTRs. The correct way to calculate the hourly cost of an FTR is to calculate its cost for the effective period only for hours in which it is effective. On June 24, 2019, PJM filed with FERC to amend their tariff to properly account for the hourly cost of an FTR.[67]

65 PJM. "*Report of the Independent Consultants on the GreenHat Default*," P33. March 18, 2019 <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.
66 *See* "Financial Risk Mitigation Senior Task Force Charter," MRC. April 25, 2019.
67 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).

FERC Order on FTR Forfeitures

On January 19, 2017, FERC determined that the application of the current FTR forfeiture rule to INCs, DECs and UTCs was unjust and unreasonable.[68] In their determination, FERC ordered that a method should be developed to consider the net impact of a participant's entire portfolio of virtual bids on a constraint related to an FTR position and ordered that counter flow FTRs be included in FTR forfeiture calculations.

FERC ordered a retroactive effective date meaning that participants would be retroactively billed their FTR forfeiture amounts based on the new FTR forfeiture rule once it was in place.

Until January 19, 2017, an FTR holder was subject to forfeiture of any profits from an FTR if it met the criteria defined in Section 5.2.1(b) of Schedule 1 of the OA. 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.

After January 19, 2017, participants were subject to the new FTR forfeiture rule. This rule considers the impact of a participant's net virtual transaction portfolio on all constraints. If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the line limit, and that constraint affects an individual FTR's target allocation by $0.01, the FTR is subject to FTR forfeiture if the net virtual portfolio increased the value of the FTR. FTR forfeitures do not result from net virtual portfolios that decrease the value of their affiliates' FTRs. The forfeiture amount calculation

68 *See* 158 FERC ¶ 61,038.

is the hourly profit of the FTR and an FTR cannot forfeit more than once per hour.

Figure 13-14 shows the monthly FTR forfeitures under the newly established FTR forfeiture rule from January 19, 2017, through June 30, 2019. PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the interim period from January 2017 through September 2017 participants did not know what behaviors were causing FTR forfeitures, so they had no way to modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures were down significantly, and stabilized, as participants could now see the effect of their activities on FTR forfeitures. For the period of January 19, 2017, through June 30, 2019, total FTR forfeitures were $14.5 million.

Figure 13-14 Monthly FTR forfeitures for physical and financial participants