Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has added increasingly complex rules and regularly intervenes in the FTR mechanism as the PJM FTR design has moved further and further from these economic fundamentals. Some market participants have profited in various ways from these design flaws and those market participants now strongly defend the current design. The customers who ultimately pay congestion are generally not aware of the FTR design and do not understand the extent to which the design fails to offset their congestion payments.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets.

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 combined day-ahead and balancing (real-time) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. But most load was served by intrazonal generation. 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. There was no congestion revenue because customers paid only the actual cost of the low cost generation. The flawed idea that congestion is based on contract paths was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load.

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

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP, but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, 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 or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when 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 (real-time) congestion to load. Congestion, in PJM's two settlement market, is the sum of day-ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR design, the load still owns the rights to congestion revenue, but the ARR design 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 design, the right to all congestion revenues should belong to load. All congestion surplus should be assigned to load. But the actual implementation produces a very different result.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not and do not account for all congestion. The use of contract paths led to the mistaken conclusion that some congestion did not belong to load and could be sold to FTR buyers. The ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR payments are less than target allocations. So called surplus revenue is paid to FTR holders to ensure payment, despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. This

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

divergence between actual network use and historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of generating units retired and new units were added.[3] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The product is defined as the difference in congestion prices across specific transmission contract paths. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues. The quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

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 fact that ARR holders cannot set the sale price for congestion revenue rights, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach 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.

The cumulative offset by ARRs for the 2011/2012 planning period through the 2022/2023 planning period, using the rules effective for each planning period, was 69.5 percent. Load has been underpaid by $3.8 billion from the 2011/2012 planning period through the 2022/2023 planning period. This is an increase of $0.4 billion from the $3.4 billion that load was underpaid from the 2011/2012 planning period through the 2021/2022 planning period.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

3 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. 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.

The *2023 Quarterly State of the Market Report for PJM: January through June* focuses on the 2022/2023 planning period as well as the 2023/2024 Long Term and Annual FTR auctions and ARR allocation, specifically covering June 1, 2022, through May 31, 2023. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in the first six months of 2023.

Table 13-1 The FTR/ARR markets results were partially competitive

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2023/2026 Long Term FTR Auction, the 2023/2024 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2022/2023 Annual FTR Auction. Ownership of FTRs is disproportionately (75.4 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- 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 and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers

when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Overview

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2023/2024 planning period ARRs were allocated to 1,504 individual participants, held by 123 parent companies, down from 1,566 individual parents, held by 133 parent companies in the 2021/2022 planning period. ARR ownership for the 2022/2023 planning period was unconcentrated with an HHI of 617, up from 584 for the 2021/2022 planning period.

Market Behavior

- **Self Scheduled FTRs.** For the 2022/2023 planning period, 24.1 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the 2022/2023 planning period, ARRs and self scheduled FTRs offset 78.8 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the 2022/2023 planning period. The cumulative offset for that period was 69.5 percent of total congestion.
- **ARR Payments.** For the 2022/2023 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,350.4 million, while PJM collected $1,664.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2021/2022 planning period, the ARR target allocations were $634.2 million while PJM collected $812.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **Residual ARRs.** Residual ARRs are only available on contract 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 2022/2023 planning period, PJM allocated a total of 34,502.8 MW of residual ARRs with a total target allocation of $38.1 million, up from 27,619.2 MW, with a total target allocation of $18.8 million, in the 2021/2022 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 38,774 MW of ARRs associated with $2,100,400 of revenue that were reassigned for the 2022/2023 planning period. There were 32,935 MW of ARRs associated with $659,700 of revenue that were reassigned in the 2021/2022 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.4 percent of prevailing flow and 92.6 percent of counter flow FTRs for the first six months of 2023. Financial entities owned 75.4 percent of all prevailing and counter flow FTRs, including 64.5 percent of all prevailing flow FTRs and 87.2 percent of all counter flow FTRs during the first six months of 2023. Self scheduled FTRs account for 4.8 percent of all FTRs held.

- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the 2022/2023 planning period, ownership of cleared prevailing flow bids was unconcentrated in 93.6 percent of periods and moderately concentrated in 6.4 percent of periods. Ownership of cleared counter flow bids was unconcentrated in 39.7 percent of periods and moderately concentrated in 60.3 percent of periods.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the 2023/2026 Long Term FTR Auction, total participant FTR sell offers were 865,052 MW. In the 2023/2024 Annual FTR Auction, total participant FTR sell offers were 898,579 MW. In the Monthly Balance of Planning Period FTR Auctions for the 2022/2023 planning period, total participant FTR sell offers were 22,226,131 MW.
- **Buy Bids.** In the 2023/2026 Long Term FTR auction, total FTR buy bids were 1,388,159 MW, down 41.9 percent from 2,387,443 MW the previous long term auction. There were 3,773,919 MW of buy and self scheduled bids in the 2023/2024 Annual FTR Auction, up 87.8 percent from 2,010,076 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2022/2023 planning were 41,044,503 MW, up 41.6 percent from 28,976,966 in the 2021/2022 planning period.
- **FTR Forfeitures.** Total FTR forfeitures were $4.6 million for the 2022/2023 planning period.
- **Credit.** There have been three collateral defaults and one payment default in the first six months of 2023.

Market Performance

- **Quantity.** In the 2023/2026 Long Term FTR Auction 282,258 MW (20.3 percent) of buy bids cleared and 346,357 MW (12.3 percent) of sell offers cleared. In the Annual FTR Auction for the 2023/2024 planning period 878,232 MW (23.3 percent) of buy and self scheduled bids cleared, up 72.5 percent from 509,687 (25.4 percent) for the previous planning period. In the 2022/2023 planning period, Monthly Balance of Planning Period FTR Auctions cleared 7,303,241 MW (19.6 percent) of FTR buy bids and 3,483,021 MW (15.7 percent) of FTR sell offers. For the 2021/2022 planning period, Monthly Balance of Planning Period FTR Auctions cleared 5,685,798 MW (19.6 percent) of FTR buy bids and 3,152,820 MW (20.2 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2023/2026 Long Term FTR Auction was $0.13 per MW, up from $0.05 from the 2022/2025 Long Term FTR Auction. The weighted average buy bid FTR price in the Annual FTR Auction for the 2023/2024 planning period was $3.37 per MW, up from $1.72 per MW in the 2022/2023 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the 2022/2023 planning period was $0.48 per MWh, up from $0.20 per MWh in the 2021/2022 planning period.
- **Revenue.** The 2023/2026 Long Term FTR Auction generated $184.5 million of net revenue for all FTRs, up 153.7 percent from $72.8 million from the 2022/2025 Long Term FTR Auction. The 2023/2024 Annual FTR Auction generated $1,694.3 million in net revenue, up 12.8 percent from $1,501.5 million for the 2022/2023 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $106.0 million in the 2022/2023 planning period, up 110.7 percent from $50.3 million in the 2021/2022 planning period.
- **Revenue Adequacy.** FTRs were paid 100.0 percent of the target allocations for the 2022/2023 planning period, including distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the 2022/2023 planning period, profits for all participants were $372.1 million. In the 2022/2023 planning period, physical entities lost $4.6 million on FTRs purchased directly (not self scheduled), down from $263.5 million in profits in the

2021/2022 planning period. Financial entities received $376.7 million in profits, down from $831.5 million profits in the 2021/2022 planning period.

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
2023/2026 Long Term	6/2/2022	3/3/2023
2023/2024 ARR	3/1/2023	3/24/2023
2023/2024 Annual	4/4/2023	4/27/2023
2024/2027 Long Term	6/1/2023	3/1/2024

Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- 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 all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue 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 IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported Q1 2022. Status: Not adopted.)[4]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. 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 reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of 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 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 Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market

4 If adopted, this recommendation would replace the next two recommendations.

should 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 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.)

Surplus

- 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 by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[5] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- 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.)

5 See "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23, 2023).

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. First reported 2021. Status: Not adopted.)

Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by load of their congestion revenue rights.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

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 including so called revenue adequacy. 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.[6] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[7] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays 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 total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

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 only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to load. Beginning with the 2018/2019 planning

6 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

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

period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[8] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.5 percent of total congestion. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the 2022/2023 planning period. The cumulative offset for that period was 69.5 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

PJM proposed, and on March 11, 2022, FERC accepted, to increase Stage 1A ARR allocations from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[9] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. PJM's new ARR allocation rules have increased Stage 1A rights at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's new ARR allocation rules have exacerbated the current misalignment between congestion property rights and the congestion paid by load.

8 163 FERC ¶ 61,165 (2018).
9 See 178 FERC ¶ 61,170.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the network congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy, and generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of CRR that was sold to the third party. Depending on actual congestion, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic contract path based approach, and sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers, despite the fact that FTR buyers willingly paid a defined price for FTRs. PJM has significant discretion over the level of supply made available to FTR buyers. The appropriate goals of that discretion should 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 the ARR sink and source from the Annual FTR Auction.[10] ARR target allocations are a set value at the time of the Annual FTR Auction. It is logically possible for ARRs to be revenue inadequate if the money collected from the FTR auction is not enough to pay the entirety of ARR target allocations for the planning period. This is extremely unlikely and can only happen if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. In the current approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR

10 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

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.

Market Design

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, DUQ and DOM Control Zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least ten planning periods regardless of system or regulatory changes.[11]

The 2022/2023 planning period annual auction was the first auction under PJM's new ARR allocations rules. Under the new rules Stage 1A ARR allocations increase from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[12] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. PJM's new ARR allocation rules have increased Stage 1A rights at the cost of Stage 1B and Stage 2 ARR allocations.

In Stage 1A, LSEs can obtain ARRs, based on their contribution to the network service peak load (NSPL) and based on generation to load contract paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired and PJM has replaced it. The historical reference year is the year in which PJM markets were implemented, 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, subject to a cap of 60 percent of the participants total network service peak load for the zone or load aggregation zone that the ARRs are obtained. Effective for the 2023/2024 planning period, network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of 60 percent of the participants total network service peak load for the zone or load aggregation zone that the ARRs are obtained. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[13] PJM does not actually upgrade the transmission system to address Stage 1A ARR infeasibility because there is no actual physical infeasibility. The apparent infeasibility is an artificial result based on the fiction that power flows on the outdated and irrelevant generation to load contract paths on which PJM's current and incorrect ARR allocation is based. Stage 1A rights have nothing to do with actual power flows or transmission limits.

In Stage 1B, network transmission service customers can obtain ARRs, up to the difference between their share of network service peak load and Stage 1A allocations. Effective for the 2023/2024 planning period, Stage 1B ARRs can be obtained from historical generation resources, qualified replacement resources, hubs, zones, or interfaces to designated load aggregation zones. 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.

In Stage 2, 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, load aggregation zone, or any generator, interface, hub or zone, up to their total peak network load in that zone. Firm,

11 See "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23, 2023) at 23.
12 See 178 FERC ¶ 61,170.
13 See "PJM Manual 6: Financial Transmission Rights," Rev 31 (Feb. 23, 2023).

point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable target allocations rather than the fixed ARR value determined in the annual FTR auction. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[14] ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs 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.[15]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[16] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[17] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion exists or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

Market Structure

ARRs are allocated on an annual basis. For the 2022/2023 planning period there were 1,563 individual participants and 133 parent companies.

14 OATT Attachment K 7.1.1.(b).
15 See "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23, 2023) at 35.
16 156 FERC ¶ 61,180 (2016).
17 See FERC Docket No. EL16-6-003.

The ownership of ARRs was unconcentrated, with an HHI of 584, for the 2022/2023 planning period.

Market Performance

Volume

Table 13-3 shows the MW of ARR allocations for each round of the 2022/2023 and 2023/2024 planning periods. There was a 1,214 MW increase (0.8 percent) in Network Service Peak Load (NSPL) between the 2022/2023 and 2023/2024 planning period. This increase and the change from Zonal Base Load to 60 percent of Network Service Peak Load for Stage 1A ARRs resulted in an increase in ARR MW requested by load in the annual auction of 30,546 MW (17.6 percent) from the 2022/2023 to the 2023/2024 planning period. But there was only an 8,038 MW increase (7.8 percent) in the ARR MW actually provided to load from the 2022/2023 to the 2023/2024 planning period. The increase in Stage 1A ARR MW resulted in a decrease in Stage 1B ARR MW by 9,430 MW from the 2022/2023 to the 2023/2024 planning period. The total cleared volume of Stage 1B ARR MW decreased 36.2 percentage points from 58.1 percent in the 2022/2023 planning period to 21.9 percent in the 2023/2024 planning period.

Table 13-3 Annual ARR allocation volume: 2022/2023 and 2023/2024 planning periods

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2022/2023	1A	0	30,574	71,579	71,579	100.0%	0	0.0%
	1B	1	16,452	35,648	20,720	58.1%	14,928	41.9%
	2	2	13,638	22,458	2,851	12.7%	19,607	87.3%
		3	7,090	22,214	3,686	16.6%	18,528	83.4%
		4	5,899	22,024	4,384	19.9%	17,640	80.1%
		Total	26,627	66,696	10,921	16.4%	55,775	83.6%
	Total		73,653	173,923	103,220	59.3%	70,703	40.7%
2023/2024	1A	0	36,717	87,085	87,073	100.0%	12	0.0%
	1B	1	10,454	51,491	11,290	21.9%	40,201	78.1%
	2	2	11,170	32,848	5,325	16.2%	27,523	83.8%
		3	10,687	33,045	7,570	22.9%	25,475	77.1%
		Total	21,857	65,893	12,895	19.6%	52,998	80.4%
	Total		69,028	204,469	111,258	54.4%	93,211	45.6%

Table 13-4 shows the share of ARR MW, by stage, for ARRs with paths that source inside or outside the zone where the load is located, for the 2023/2024 planning period. Table 13-4 shows that 77.9 percent of the ARR MW are based on generation inside the zone where the ARR load is located and 22.1 percent of the ARR MW are based on generation outside the zone where the ARR load is located, compared to only 9.8 percent of congestion resulting from constraints inside of the zone that load is located, and 90.2 percent of congestion resulting from constraints outside if the zone that load is located during the 2022/2023 planning period (see Table 13-50). This illustrates one of the fundamental issues with the path based approach which originated in a cost of service design where most load was served by generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load. The path based approach cannot reflect the actual congestion paid by load.

Table 13-4 Share of ARRs that source in/out of load zone: 2023/2024 planning period

	Stage 1A		Stage 1B		Stage 2		Total	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	26.1%	36.9%	16.6%	0.5%	6.4%	13.5%	49.1%	50.9%
AEP	7.9%	59.7%	1.5%	13.9%	0.8%	16.2%	10.1%	89.9%
APS	8.4%	73.8%	4.4%	6.2%	4.4%	2.7%	17.3%	82.7%
ATSI	29.5%	52.0%	2.4%	4.1%	1.3%	10.6%	33.2%	66.8%
BGE	33.5%	40.2%	3.9%	13.8%	0.5%	8.0%	38.0%	62.0%
COMED	0.0%	66.6%	0.0%	8.3%	0.0%	25.1%	0.0%	100.0%
DAY	62.7%	6.1%	9.3%	6.2%	15.2%	0.5%	87.2%	12.8%
DOM	0.4%	85.4%	0.1%	5.8%	0.0%	8.4%	0.4%	99.6%
DPL	17.4%	50.8%	3.3%	0.8%	2.6%	25.2%	23.2%	76.8%
DUKE	31.8%	33.7%	4.9%	3.8%	8.3%	17.5%	45.0%	55.0%
DUQ	77.5%	1.2%	3.3%	0.0%	15.5%	2.6%	96.2%	3.8%
EKPC	51.1%	0.0%	32.7%	0.0%	16.2%	0.0%	100.0%	0.0%
EXT	49.6%	0.0%	49.6%	0.0%	0.7%	0.0%	100.0%	0.0%
JCPL	3.9%	62.7%	22.2%	0.3%	8.5%	2.4%	34.6%	65.4%
MEC	33.0%	39.7%	5.0%	0.3%	0.8%	21.2%	38.8%	61.2%
OVEC	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	0.0%
PE	13.5%	53.0%	0.1%	11.8%	2.6%	19.1%	16.2%	83.8%
PECO	14.9%	65.5%	0.8%	5.0%	5.9%	7.9%	21.6%	78.4%
PEPCO	38.9%	35.0%	6.6%	1.0%	1.7%	16.7%	47.2%	52.8%
PPL	0.0%	79.3%	2.3%	5.4%	0.2%	12.8%	2.6%	97.4%
PSEG	22.8%	36.6%	13.6%	0.2%	11.4%	15.3%	47.8%	52.2%
REC	0.0%	0.0%	50.2%	0.0%	49.8%	0.0%	100.0%	100.0%
Total	15.0%	57.7%	3.9%	6.6%	3.2%	13.6%	22.1%	77.9%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. 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. 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 contract 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 2023/2024 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. Stage 1A related over allocations have to be made up elsewhere in PJM's FTR market model, in the form of reduced system capability, in order for PJM to achieve its goal of fully funding FTRs.

Table 13-5 shows the MW quantity and count of overloaded facilities and the reasons for the modeled overload for the 2022/2023 and 2023/2024 planning periods. In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM needed to raise the modeled capacity limits above the actual transmission line limits on 68 facility/contingency pairs, 45 of which were internal to PJM, a total of 11,629 MW in the 2023/2024 planning period, an increase of 23 facility/contingency pairs (51.1 percent), an increase of 24 facility/contingency pairs internal to PJM, (114.3 percent), and an increase of 8,244 MW (243.5 percent) compared to the 2022/2023 planning period.[18]

18 *PJM 2023/2024 Stage 1A Over allocation notice*, PJM FTRs, <https://pjm.com/-/media/markets-ops/ftr/annual-arr-allocation/2023-2024/2023-2024-stage-1a-over-allocation-notice.ashx> (March 6, 2023).

Table 13-5 Stage 1A overloaded facility reasons and MW: 2022/2023 and 2024/2024 planning periods

		2022/2023		2023/2024	
Reason	Type	MW	Count	MW	Count
Network Load	M2M Flowgate	2,007	18	2,057	19
Transmission Outage	Internal PJM	1,300	21	9,506	45
Transmission Outage	M2M Flowgate	78	6	62	3
Transmission Outage	Tie Line	0	0	4	1
Total		3,385	45	11,629	68

Table 13-6 shows the share of Stage 1A over allocations for the 2022/2023 and 2023/2024 planning periods for ARR allocations that source inside and outside the zone where the over allocated MW sink. The share of over allocated capacity that has a source outside the zone in which it sinks, decreased 10.8 percent from 37.8 percent in the 2022/2023 planning period to 27.0 percent in the 2023/2024 planning period.

Table 13-6 Stage 1A overloaded paths that sink inside and outside source zone: 2022/2023 and 2023/2024

	2022/2023 Planning Period				2023/2024 Planning Period			
	MW		Proportion		MW		Proportion	
	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone
ACEC	0.0	0.0	NA	NA	0.0	0.2	0.0%	100.0%
AEP	3,750.8	556.1	87.1%	12.9%	4,288.5	811.8	84.1%	15.9%
APS	1.8	447.9	0.4%	99.6%	0.1	478.0	0.0%	100.0%
ATSI	1,920.1	1,271.7	60.2%	39.8%	2,783.3	1,985.7	58.4%	41.6%
BGE	0.0	533.8	0.0%	100.0%	0.0	461.7	0.0%	100.0%
COMED	2,260.8	0.0	100.0%	0.0%	3,271.0	0.0	100.0%	0.0%
DAY	0.0	234.9	0.0%	100.0%	0.0	504.8	0.0%	100.0%
DOM	0.0	1,072.0	0.0%	100.0%	4,757.3	3.9	99.9%	0.1%
DPL	45.0	123.0	26.8%	73.2%	68.4	45.7	59.9%	40.1%
DUKE	0.0	1,344.6	0.0%	100.0%	0.0	1,330.2	0.0%	100.0%
DUQ	0.0	161.4	0.0%	100.0%	0.0	177.7	0.0%	100.0%
EKPC	406.1	59.1	87.3%	12.7%	0.0	100.0	0.0%	100.0%
JCPL	0.0	0.0	NA	NA	0.0	21.6	0.0%	100.0%
MEC	236.9	408.9	36.7%	63.3%	0.0	5.1	0.0%	100.0%
PE	138.4	78.3	63.9%	36.1%	582.6	220.5	72.5%	27.5%
PECO	0.0	85.7	0.0%	100.0%	223.7	0.0	100.0%	0.0%
PEPCO	0.0	179.1	0.0%	100.0%	286.7	166.6	63.2%	36.8%
PPL	1,548.0	0.8	99.9%	0.1%	916.0	0.0	100.0%	0.0%
PSEG	74.3	0.0	100.0%	0.0%	0.0	48.5	0.0%	100.0%
TOTAL	10,382.2	6,557.3	61.3%	38.7%	17,177.6	6,362.0	73.0%	27.0%

Figure 13-1 shows the predicted and estimated impact of Stage 1A infeasibilities on FTR funding for the 2012/2013 through 2022/2023 planning periods, as well as the predicted impact on funding for the 2022/2023 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. 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 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

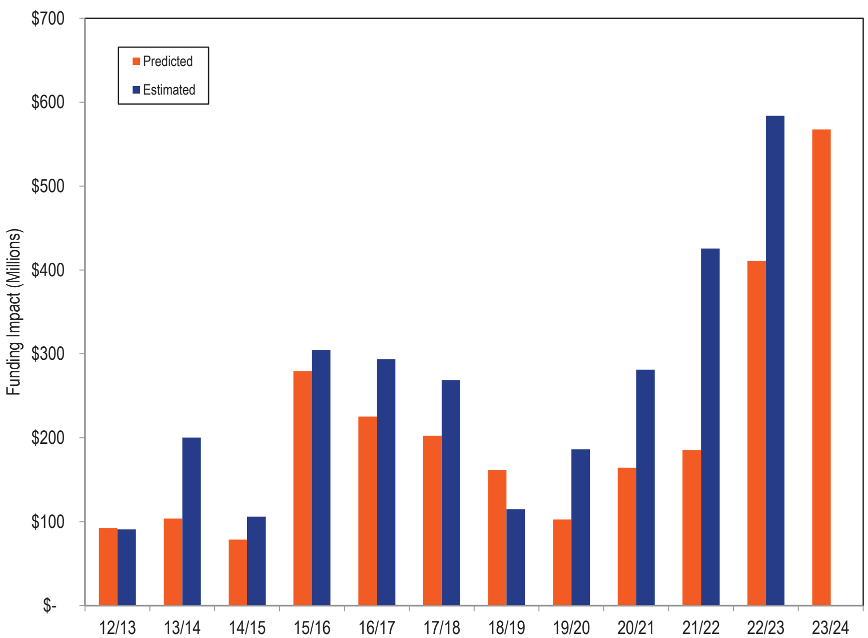


Table 13-7 shows the MW of retired generation sources for Stage 1A ARRs, the QRR MW assigned by PJM for all resources and the replacement MW that were considered rate based. A rate based unit is a replacement generator that is owned by the ARR holder, or subject to firm energy and capacity supply contracts. The term rate based is a misleading reference to the premarket cost of service regulation paradigm. If PJM does not find such a unit, PJM will use another unit that is close to where the retired unit was located even if it is not owned or under contract. It is not clear why PJM created the synthetic zone Midatlantic for the QRR assignment.

Table 13-7 Qualified Replacement Resource results: 2023/2024

Zone	Historical Retired	Replacement (All)	Replacement (Rate-based)
AEP/DAY	10,741.1	8,041.5	1,847.8
ATSI	5,614.3	3,724.9	40.9
COMED	7,153.8	5,097.1	4.5
DEOK	3,234.5	2,029.2	57.6
DOM	4,210.6	5,972.7	5,119.9
DUQ	2,045.0	811.7	0.0
EKPC	198.1	229.3	0.0
Midatlantic	22,684.2	16,385.0	375.2
OVEC	0.0	459.2	1,854.0
Total	55,881.6	42,750.6	9,299.9

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[19] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs 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

19 See "PJM Manual 6: Financial Transmission Rights," Rev.31 (Feb. 23, 2023).

in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

Table 13-8 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2021 and May 2023.

There were 38,774 MW of ARRs associated with $2,100,400 of revenue that were reassigned for the 2022/2023 planning period. There were 32,935 MW of ARRs associated with $659,700 of revenue that were reassigned for the 2021/2022 planning period.

Table 13-8 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2021 through May 2023

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2021/2022 (12 months)	2022/2023 (12 months)	2021/2022 (12 months)	2022/2023 (12 months)
ACEC	300	335	$1.9	$2.4
AEP	4,142	4,488	$49.0	$160.2
APS	1,325	1,896	$15.5	$113.4
ATSI	3,353	8,090	$45.2	$286.8
BGE	2,393	2,569	$233.9	$310.7
COMED	3,056	2,391	$23.7	$27.4
DAY	1,074	1,154	$5.1	$9.0
DUKE	1,467	2,375	$60.7	$249.0
DUQ	1,662	1,489	$8.1	$14.0
DOM	120	197	$1.7	$5.1
DPL	832	851	$53.0	$66.3
EKPC	0	0	$0.0	$0.0
JCPLC	963	882	$2.0	$7.1
MEC	1,162	1,468	$9.4	$163.8
OVEC	0	0	$0.0	$0.0
PECO	3,315	2,413	$14.7	$56.7
PE	887	1,169	$11.5	$78.0
PEPCO	1,771	1,832	$44.1	$104.1
PPL	3,959	4,102	$63.3	$400.3
PSEG	1,116	999	$16.8	$45.2
REC	39	75	$0.1	$0.6
Total	32,935	38,774	$659.7	$2,100.4

Revenue

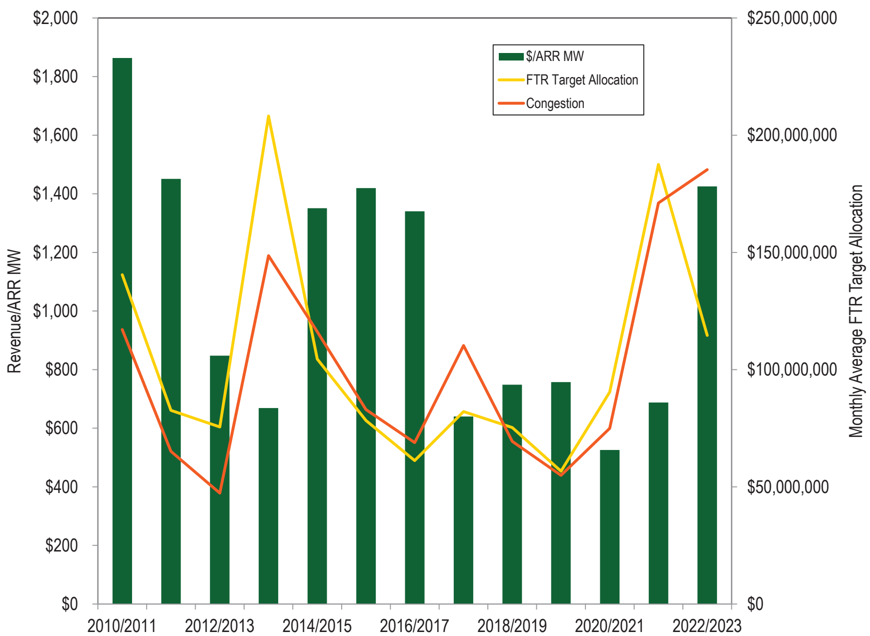
ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions, which generally exceeds the sum of the ARR target allocations.

Figure 13-2 shows the revenue per ARR MW held for each month of the 2010/2011 planning period through the 2022/2023 planning period. The revenue per ARR MW held does not include target allocation related payouts for self scheduled FTRs or surplus revenue, but does include Residual ARRs starting in August 2012.

PJM has had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. 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 relative to prior years. The decrease in system capability caused by PJM's more conservative modeling of the FTR market model reduced Stage 1B and Stage 2 ARR allocations. The increased FTR prices resulted in an increase in revenue per ARR MW, but there are 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 due to an increase in modeled capability. For the 2017/2018 and 2018/2019 planning periods the revenue per MW of ARR was $5,168 and $6,841. For the 2022/2023 planning period, cleared ARR MW decreased significantly (see Table 13-3) from the previous planning period, indicating that PJM again chose more restrictive modeling criteria for the FTR model to improve FTR funding. This results in fewer ARRs being awarded. Due to significant increases in FTR prices in the 2022/2023 planning period, the revenue per MW of ARR was $12,274, a 96.9 percent increases from the 2021/2022 planning period.

Under the current rules, load is required to directly pay balancing congestion costs, not included in Figure 13-2, which reduce the revenue received by ARR holders. There is no support for the assertion made by proponents of shifting balancing congestion to load that higher ARR values would result, and there is no evidence of any kind that load is better off as a result of the arbitrary assignment of balancing congestion to load.

Figure 13-2 Revenue per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2022/2023



ARR holders have limited options to pick source points for their ARRs. The holders of Stage 1A rights are limited to specific historical sources (or PJM defined replacement sources when resources retire). Of the stage 1A rights allocated to ARR holders, 57.7 percent were sourced within the ARR holder's zone in the 2023/2024 planning period. Overall, 77.9 percent of all ARRs allocated to ARR holders were sourced within the ARR holders zone in the 2023/2024 planning period (see Table 13-4). In contrast, the source of a load zone's actual congestion is, in significant part, the result of transmission constraints that separate that zone from resources external to that zone, not by constraints that limit access to internal resources. For example, in the 2022/2023 planning period, only 9.8 percent of congestion resulted from constraints within the same zone where that load is located (see Table 13-50). The congestion offset revenues per MW of internally sourced Stage 1A ARR rights are less than the revenue per MW of Stage 1A ARR rights from externally sourced resources. Table 13-9 shows the share of ARR revenue, by stage, for ARRs with paths that source inside or outside the zone where the load is located, for the 2023/2024 planning period. While 15.0 percent of all ARR MW are Stage 1A ARRs with sources outside the zone where load is located (see Table 13-4), those ARRs provide 22.7 percent of the total ARR revenues.

This illustrates one of the fundamental issues with the path based approach which originated in a cost of service design where most load was served by, or assumed to be served by, generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion is based on constraints that are not in the same zone as load. The path based approach does not and cannot reflect the actual congestion paid by load. The use of the path based approach is the fundamental source of the under assignment of congestion revenue rights to load in the ARR/FTR model.

Table 13-9 Share of ARR revenue that sources in/out of load zone: 2023/2024 planning period

	Stage 1A		Stage 1B		Stage 2		Total	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	30.7%	35.6%	15.3%	0.4%	7.5%	10.5%	53.5%	46.5%
AEP	16.9%	54.4%	2.1%	8.5%	1.7%	16.3%	20.7%	79.3%
APS	22.8%	64.8%	2.3%	3.3%	5.2%	1.5%	30.3%	69.7%
ATSI	68.8%	23.8%	1.2%	0.1%	0.7%	5.4%	70.7%	29.3%
BGE	82.4%	14.1%	1.9%	1.1%	0.0%	0.5%	84.3%	15.7%
COMED	0.0%	60.2%	0.0%	1.6%	(0.1%)	38.3%	(0.1%)	100.1%
DAY	83.4%	(0.1%)	6.2%	0.1%	10.0%	0.4%	99.6%	0.4%
DOM	0.6%	91.9%	0.0%	4.5%	0.0%	3.0%	0.6%	99.4%
DPL	22.9%	56.4%	2.5%	0.3%	2.7%	15.3%	28.0%	72.0%
DUKE	70.6%	15.6%	2.5%	1.0%	3.8%	6.6%	76.8%	23.2%
DUQ	87.9%	(0.1%)	4.1%	(0.0%)	7.6%	0.5%	99.6%	0.4%
EKPC	85.3%	0.0%	11.3%	0.0%	3.4%	0.0%	100.0%	0.0%
EXT	49.6%	0.0%	49.6%	0.0%	0.7%	0.0%	100.0%	0.0%
JCPL	7.1%	31.6%	49.4%	0.1%	9.6%	2.3%	66.0%	34.0%
MEC	30.1%	28.6%	2.0%	0.0%	0.0%	39.3%	32.1%	67.9%
OVEC	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	0.0%
PE	29.1%	50.0%	0.1%	0.2%	3.5%	17.2%	32.7%	67.3%
PECO	1.5%	93.1%	0.0%	(0.4%)	1.7%	4.1%	3.2%	96.8%
PEPCO	83.9%	10.9%	3.4%	0.2%	0.1%	1.5%	87.4%	12.6%
PPL	(0.0%)	91.5%	(0.1%)	2.8%	0.1%	5.7%	(0.0%)	100.0%
PSEG	22.8%	47.8%	9.0%	0.2%	4.4%	15.9%	36.1%	63.9%
REC	0.0%	0.0%	42.4%	0.0%	57.6%	0.0%	100.0%	0.0%
Total	22.7%	62.9%	1.7%	3.3%	1.3%	8.1%	25.7%	74.3%

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 can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month 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.[20] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-10 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. In the 2022/2023 planning period, PJM allocated a total of 34,502.8 MW of Residual ARRs with a target allocation of $38.1 million. In the 2021/2022 planning period, PJM allocated a total of 27,619.2 MW of residual ARRs with a target allocation of $18.8 million.

Table 13-10 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2022/2023 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021	43,484.2	25,028.0	57.6%	$11,677,033.36
2021/2022	46,092.0	27,619.2	59.9%	$18,806,123.46
2022/2023	71,068.9	34,502.8	48.5%	$38,140,961.08

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

IARRs

In theory, 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 result in 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.[21]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability. [22] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. There have been 13 successful IARR requests totaling 2,990.1 MW. One IARR path of 64.5 MW was terminated (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs. Of these 12 unique paths, three paths consisting of 1,200.0 MW were based on specific transmission investments requests, six paths consisting of 1,047.4 MW were based on merchant transmission requests and three paths consisting of 678.6 MW were based on customer funded (RTEP) transmission projects. The three paths based on specific transmission investments involved a generation company working with its affiliated transmission company. The other nine paths were based on projects that would have been built regardless of the addition of IARRs.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[23]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[24] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights, which are given first and absolute priority in PJM's annual allocation process. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

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. These day-ahead congestion price differences, multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define

21 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.
22 See Attachment EE of the PJM Open Access Transmission Tariff <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.
23 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").
24 *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006) ("Order No. 681"), *order on reh'g*, Order No. 618-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes. The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, auction revenues greater than ARR target allocations, and any charges made to day-ahead operating reserves which occur where there are hours with net negative congestion. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Target allocations are a cap on payments to FTR holders for each planning period. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. 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 period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. 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. 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.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not fully recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. PJM's objective in the auctions is to maximize auction revenue, given the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is no requirement to report bilateral transactions, or any information about them, to PJM.

Supply and Demand

Total FTR supply in each auction is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

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

The FTR 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.[25] 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 will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

Long Term FTR Auctions

In July 2006, FERC approved Order No. 681 mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets. 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."[26] 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. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and is only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM 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 revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages, determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. Capacity awarded in the Long Term FTR Auction is unavailable as ARRs in years two and three. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all possible capacity for ARR holders in the first year of the Long Term Auction due to

25 See the *2022 State of the Market Report for PJM*, Volume II, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.
26 Order No. 681 at P 17.

changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[27] 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, is not defined 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. The Annual FTR Auction consists of four rounds that allow any PJM member 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.

Monthly Balance of Planning Period FTR Auctions

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. 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. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[28]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

For bilateral trades reported to 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. Bilateral FTRs reported to PJM can also include 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. Once the bilateral transaction is reported to PJM, PJM transfers ownership and adjusts credit requirements accordingly. Participants have used bilateral trades reported to PJM to reduce their credit requirements.

There is no reason to continue to permit bilateral transactions outside the PJM market and outside the awareness of PJM. The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market in order to provide full transparency consistent with the rest of the FTR market and to ensure no credit issues are missed.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. Physical

27 See "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23, 2023).

28 See "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23, 2023).

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.

Table 13-11 shows the 2023/2026 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 84.9 percent of prevailing flow buy bid FTRs and 90.7 percent of counter flow buy bid FTRs with the result that financial entities purchased 87.6 percent of all long term FTR auction cleared buy bids. Physical entities purchased 15.1 percent of all cleared long term FTRs in the 2023/2026 Long Term FTR Auction, down 2.0 percentage points from the previous Long Term FTR Auction.

Table 13-11 Long term FTR auction patterns of ownership by FTR direction: 2023/2026

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	15.1%	9.3%	12.4%
	Financial	84.9%	90.7%	87.6%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	3.5%	3.1%	3.3%
	Financial	96.5%	96.9%	96.7%
	Total	100.0%	100.0%	100.0%

Table 13-12 shows the HHI for the individual periods in the 2017/2020 through 2023/2026 Long Term FTR Auctions and the entire auction. The YRALL auction was highly concentrated until its removal in the 2020/2023 Long Term Auction. The individual annual auctions are unconcentrated with the exception of years two and three of the 17/20 Auction and year three of the 23/26 Auction.

Table 13-12 Long term HHIs by auction

Auction	YR1	YR2	YR3	YRALL	Entire Auction
17/20 Long Term Auction	779	1779	1354	8533	884
18/21 Long Term Auction	711	940	749	8654	693
19/22 Long Term Auction	492	647	768	9954	506
20/23 Long Term Auction	567	575	638	NA	463
21/24 Long Term Auction	495	535	767	NA	460
22/25 Long Term Auction	518	626	888	NA	598
23/26 Long Term Auction	496	713	1049	NA	644

Table 13-13 shows the annual FTR auction cleared FTRs for the 2023/2024 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2023/2024 planning period, financial entities purchased 80.8 percent of prevailing flow FTRs, up 12.2 percentage points, and 90.2 percent of counter flow FTRs, up 0.9 percentage points, with the results that financial entities purchased 84.2 percent, up 7.9 percentage points, of all annual FTR auction cleared buy bids for the 2023/2024 planning period.

Table 13-13 Annual FTR Auction patterns of ownership by FTR direction: 2023/2024

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	4.8%	0.0%	3.1%
		No	14.4%	9.8%	12.7%
		Total	19.2%	9.8%	15.8%
	Financial	No	80.8%	90.2%	84.2%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		5.8%	9.5%	7.5%
	Financial		94.2%	90.5%	92.5%
	Total		100.0%	100.0%	100.0%

Table 13-14 shows the HHI values for cleared buy and self scheduled bids for the 2016/2017 through 2023/2024 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 13-14 Annual auction HHIs by auction

Auction	Offset Type	Trade Type	HHI
23/24 Annual Auction	Obligation	Buy	425
	Obligation	Self Scheduled	2595
	Option	Buy	1220
22/23 Annual Auction	Obligation	Buy	424
	Obligation	Self Scheduled	3398
	Option	Buy	884
21/22 Annual Auction	Obligation	Buy	420
	Obligation	Self Scheduled	3291
	Option	Buy	957
20/21 Annual Auction	Obligation	Buy	278
	Obligation	Self Scheduled	2970
	Option	Buy	1299
19/20 Annual Auction	Obligation	Buy	251
	Obligation	Self Scheduled	2661
	Option	Buy	978
18/19 Annual Auction	Obligation	Buy	357
	Obligation	Self Scheduled	2620
	Option	Buy	1213
17/18 Annual Auction	Obligation	Buy	303
	Obligation	Self Scheduled	2794
	Option	Buy	2099

Table 13-15 presents the monthly balance of planning period FTR auction cleared FTRs in for 2023 by trade type, organization type and FTR direction. Financial entities purchased 83.4 percent of prevailing flow FTRs, up 2.4 percentage points, and 92.6 percent of counter flow FTRs, up 4.0 percentage points, from the same period in 2022, with the result that financial entities purchased 88.0 percent, up 3.2 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction for the first six months of 2023.

Table 13-15 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through May, 2023

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	16.6%	7.4%	12.0%
	Financial	83.4%	92.6%	88.0%
	Total	100.0%	100.0%	100.0%
Sell	Physical	15.9%	10.3%	14.3%
	Financial	84.1%	89.7%	85.7%
	Total	100.0%	100.0%	100.0%

Table 13-16 shows the monthly cumulative HHI values for cleared obligation MW for the 2022/2023 planning period monthly auctions for prevailing flow FTRs. Ownership of cleared prevailing flow bids was unconcentrated in 93.6 percent of periods and moderately concentrated in 6.4 percent of periods.[29]

Table 13-16 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-22	468	588	582	1119	1216	848	692	704	621	802	694	793
Jul-22		418	519	886	1059	733	758	773	717	761	719	749
Aug-22			439	900	1074	776	824	760	750	747	713	769
Sep-22				737	1124	855	973	887	887	817	726	828
Oct-22					789	809	974	841	871	828	725	813
Nov-22						603	821	724	764	781	705	743
Dec-22							523	603	642	706	678	666
Jan-23								431	582	676	669	649
Feb-23									444	661	663	649
Mar-23										566	655	638
Apr-23											549	621
May-23												546

29 See *2022 State of the Market Report for PJM*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-17 shows the monthly cumulative HHI values for cleared obligation MW for the 2022/2023 planning period monthly auctions by month for counter flow FTRs. Ownership of cleared counter flow bids was unconcentrated in 39.7 percent of periods and moderately concentrated in 60.3 percent of periods.

Table 13-17 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-22	776	735	788	930	1329	1194	1134	1383	1396	1358	945	973
Jul-22		576	614	822	1190	1092	984	1089	1113	1150	1014	973
Aug-22			573	844	1058	1017	935	1052	1085	1088	1020	961
Sep-22				744	1007	964	923	1079	1081	1150	1083	1021
Oct-22					785	974	941	1071	1126	1188	1118	1090
Nov-22						706	902	1033	1087	1135	1084	1029
Dec-22							707	1033	1103	1103	1070	1016
Jan-23								717	1062	1081	1058	1037
Feb-23									758	1039	1018	1036
Mar-23										726	986	1009
Apr-23											764	979
May-23												803

Table 13-18 shows the average daily FTR ownership for all FTRs for the 2022/2023 planning period by organization type, by FTR direction and self scheduled FTRs.

Table 13-18 Daily FTR held position ownership by FTR direction: 2022/2023 planning period

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	26.5%	12.6%	19.8%
Physical Self Scheduled	9.0%	0.2%	4.8%
Financial	64.5%	87.2%	75.4%
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 in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[30] 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.[31] The use of both of these procedures is contingent on the conditions that: PJM actions not affect 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 2023/2026 Long Term FTR Auction, 209,710 MW (21.9 percent of bid volume; 74.3 percent of total FTR volume) of counter flow FTR buy bids cleared, a decrease from 218,274 MW and an increase from 52.8 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 72,547 MW (16.8 percent of bid volume; 25.7 percent of total FTR volume) a decrease from 195,286 MW and a decrease from 47.2 percent of total FTR volume. In the 2023/2026 Long Term FTR Auction, 250,905 MW (12.8 percent) of counter flow sell offers and 95,452 MW (11.0 percent) of prevailing flow sell offers cleared.

30 See "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23, 2023).
31 See *id.*

Table 13-19 Long Term FTR Auction market volume: 2023/2026

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	126,165	414,771	116,564	28.1%	298,207	71.9%
		Year 2	84,120	251,860	26,805	10.6%	225,055	89.4%
		Year 3	85,948	290,194	66,341	22.9%	223,853	77.1%
		Total	296,233	956,825	209,710	21.9%	747,114	78.1%
	Prevailing Flow	Year 1	48,444	134,526	12,569	9.3%	121,957	90.7%
		Year 2	76,099	246,617	57,987	23.5%	188,630	76.5%
		Year 3	19,074	50,191	1,991	4.0%	48,200	96.0%
		Total	143,617	431,334	72,547	16.8%	358,787	83.2%
	Total		439,850	1,388,159	282,258	20.3%	1,105,901	79.7%
Sell offers	Counter Flow	Year 1	242,391	999,213	132,918	13.3%	866,295	86.7%
		Year 2	81,073	244,365	39,629	16.2%	204,735	83.8%
		Year 3	158,713	710,866	78,358	11.0%	632,508	89.0%
		Total	482,177	1,954,444	250,905	12.8%	1,703,539	87.2%
	Prevailing Flow	Year 1	51,320	156,799	18,793	12.0%	138,007	88.0%
		Year 2	140,389	632,778	72,405	11.4%	560,373	88.6%
		Year 3	20,478	75,475	4,254	5.6%	71,220	94.4%
		Total	212,187	865,052	95,452	11.0%	769,600	89.0%
	Total		694,364	2,819,496	346,357	12.3%	2,473,139	87.7%

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 2023/2026 auctions.

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

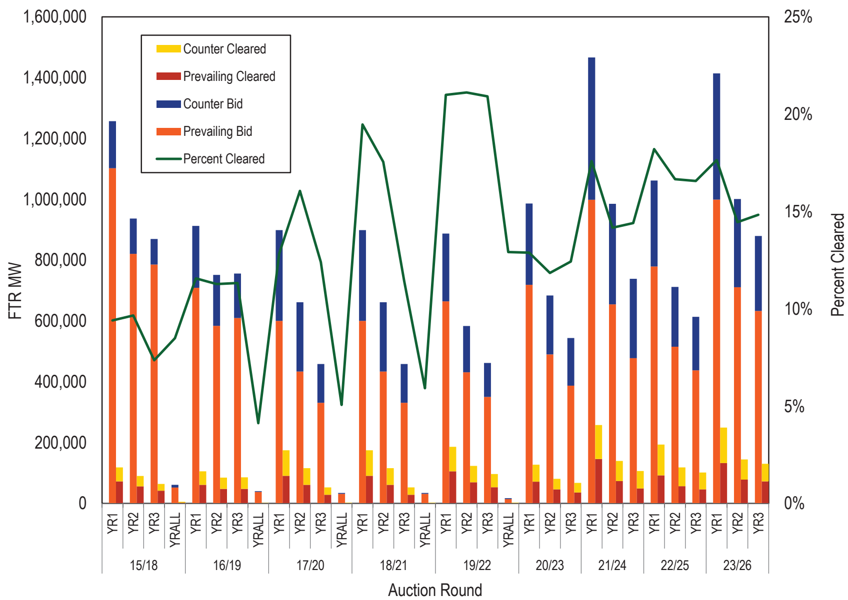


Table 13-20 compares cleared FTR obligations (not options) acquired in the Long Term FTR Auctions to the total cleared FTR obligations from the Annual FTR Auction, for FTRs in the 2014/2015 through 2023/2024 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 37.6 percent of total FTR volume in the 2014/2015 through 2023/2023 planning periods.

Table 13-20 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%
2020/2021	54,451	125,330	127,054	306,835	525,550	36.9%
2021/2022	98,829	80,998	205,008	384,835	512,449	42.9%
2022/2023	67,603	120,621	193,268	381,492	467,194	45.0%
2023/2024	100,973	118,618	249,482	469,073	770,310	37.8%

Table 13-21 shows the MW proportion of FTRs by source and sink node type for cleared buy bids in the 2023/2026 Long Term FTR Auction. Generator to generator FTRs comprise 60.1 percent of all cleared FTR buy bids, up 1.1 percentage points from the 2022/2025 Long Term FTR Auction

Table 13-21 Long Term FTR node type matrix: 2023/2026 auction

	Sink Type						
Source Type	Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.1%	6.0%	0.1%	0.2%	0.2%	0.4%	0.2%
Generator	7.3%	60.1%	2.4%	1.5%	1.3%	0.9%	3.6%
Hub	0.2%	0.6%	1.0%	0.0%	0.0%	0.4%	3.2%
Interface	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%
Load	0.2%	1.6%	0.0%	0.0%	0.2%	0.0%	0.0%
Residual Metered Aggregate	0.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.1%
Zone	0.3%	1.5%	0.9%	0.1%	0.0%	0.8%	1.8%

Annual FTR Auction

Table 13-22 shows the annual FTR auction market volume for the 2023/2024 planning period. Total FTR buy bids were 3,746,935 MW, up 88.8 percent from 1,984,377 MW for the previous planning period. For the 2023/2024 planning period 851,248 MW (22.7 percent) of buy bids cleared, up 75.9 percent from 483,988 MW (24.4 percent) for the previous planning period. There were 898,576 MW of sell offers with 91,769 MW (10.2 percent) clearing for the 2023/2024 planning period. The total volume of cleared buy and self scheduled bids was 878,232 MW, up 72.3 percent from 509,687 MW in the previous Annual FTR Auction.

Table 13-22 Annual FTR Auction market volume: 2023/2024

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	292,786	1,040,846	319,874	30.7%	720,972	69.3%
		Prevailing Flow	487,499	2,132,888	423,452	19.9%	1,709,436	80.1%
		Total	780,285	3,173,734	743,326	23.4%	2,430,408	76.6%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	121,126	573,202	107,922	18.8%	465,280	81.2%
		Total	121,126	573,202	107,922	18.8%	465,280	81.2%
	Total	Counter Flow	292,786	1,040,846	319,874	30.7%	720,972	69.3%
		Prevailing Flow	608,625	2,706,089	531,374	19.6%	2,174,715	80.4%
		Total	901,411	3,746,935	851,248	22.7%	2,895,687	77.3%
Self-scheduled bids	Obligations	Counter Flow	8	29	29	100.0%	0	0.0%
		Prevailing Flow	5,100	26,955	26,955	100.0%	0	0.0%
		Total	5,108	26,984	26,984	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	292,794	1,040,875	319,903	30.7%	720,972	69.3%
		Prevailing Flow	492,599	2,159,843	450,407	20.9%	1,709,436	79.1%
		Total	785,393	3,200,718	770,310	24.1%	2,430,408	75.9%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	121,126	573,202	107,922	18.8%	465,280	81.2%
		Total	121,126	573,202	107,922	18.8%	465,280	81.2%
	Total	Counter Flow	292,794	1,040,875	319,903	30.7%	720,972	69.3%
		Prevailing Flow	613,725	2,733,045	558,329	20.4%	2,174,715	79.6%
		Total	906,519	3,773,919	878,232	23.3%	2,895,687	76.7%
Sell offers	Obligations	Counter Flow	106,766	382,170	42,814	11.2%	339,356	88.8%
		Prevailing Flow	125,496	499,864	48,453	9.7%	451,411	90.3%
		Total	232,262	882,034	91,267	10.3%	790,768	89.7%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	4,990	16,545	502	3.0%	16,043	97.0%
		Total	4,990	16,545	502	3.0%	16,043	97.0%
	Total	Counter Flow	106,766	382,170	42,814	11.2%	339,356	88.8%
		Prevailing Flow	130,486	516,409	48,955	9.5%	467,454	90.5%
		Total	237,252	898,579	91,769	10.2%	806,810	89.8%

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 2023/2024 planning period.

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

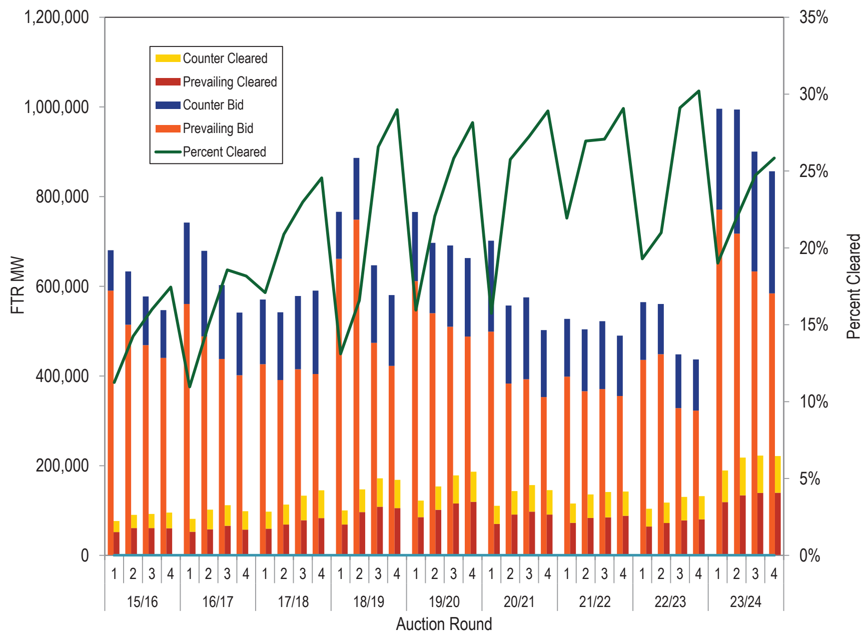


Figure 13-5 shows the proportion of ARRs self scheduled as FTRs for the last fifteen planning periods. The maximum possible level of self scheduled FTRs is equal to total ARRs. Eligible participants self scheduled 26,984 MW (24.1 percent) of ARRs as FTRs for the 2023/2024 planning period, compared to 25,699 MW (24.7 percent) in the previous planning period.

Figure 13-5 Comparison of self scheduled FTRs: 2009/2010 through 2023/2024

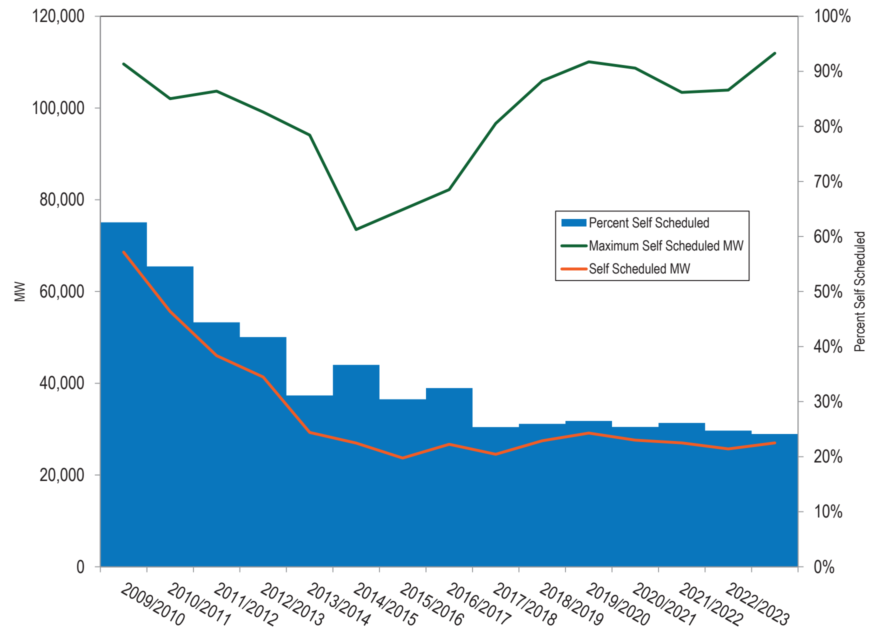


Table 13-23 shows the MW proportion of FTRs by source and sink node type for cleared buy and self scheduled bids in the 2023/2024 Annual FTR Auction.

Generator to generator FTRs comprise 51.3 percent of all cleared FTR buy and self scheduled bids, down 0.3 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 13-23 Annual auction FTR node type matrix by proportion of MW: 2023/2024

	Sink Type						
Source Type	Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	2.0%	6.0%	0.2%	0.2%	0.1%	0.4%	0.7%
Generator	10.9%	51.3%	3.9%	1.2%	0.6%	3.5%	7.7%
Hub	0.4%	0.9%	0.8%	0.1%	0.0%	0.3%	2.0%
Interface	0.1%	0.5%	0.0%	0.0%	0.0%	0.1%	0.1%
Load	0.1%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Residual Metered Aggregate	0.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%
Zone	0.5%	1.4%	0.9%	0.1%	0.0%	0.8%	1.0%

Monthly Balance of Planning Period Auctions

Table 13-24 provides the monthly balance of planning period FTR auction market volume for the entire 2021/2022 and 2022/2023 planning periods. There were 36,241,441 MW of FTR obligation buy bids and 19,672,001 MW of FTR obligation sell offers for all bidding periods in the 2022/2023 planning period.[32] The monthly balance of planning period FTR auction cleared 6,882,738 (19.0 percent) of FTR obligation buy bids and 2,840,942 MW (14.4 percent) of FTR obligation sell offers.

There were 4,803,062 MW of FTR option buy bids and 2,554,130 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2022/2023 planning period. The ownership of options was highly concentrated in all periods. The monthly auctions cleared 420,502 MW (8.8 percent) of FTR option buy bids and 642,080 MW (25.1 percent) of FTR option sell offers.

Table 13-24 Monthly Balance of Planning Period FTR Auction market volume: January through May, 2023

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-23	Obligations	Buy bids	536,658	3,138,537	680,128	21.7%	2,458,409	78.3%
		Sell offers	415,677	1,765,747	215,764	12.2%	1,549,983	87.8%
	Options	Buy bids	42,295	636,018	27,089	4.3%	608,929	95.7%
		Sell offers	73,490	236,679	67,564	28.5%	169,114	71.5%
Feb-23	Obligations	Buy bids	476,166	2,880,060	556,526	19.3%	2,323,534	80.7%
		Sell offers	356,661	1,426,578	193,042	13.5%	1,233,536	86.5%
	Options	Buy bids	31,042	437,064	26,769	6.1%	410,295	93.9%
		Sell offers	61,261	200,193	46,901	23.4%	153,292	76.6%
Mar-23	Obligations	Buy bids	413,451	2,875,283	525,283	18.3%	2,350,000	81.7%
		Sell offers	290,146	1,099,154	199,044	18.1%	900,110	81.9%
	Options	Buy bids	19,851	347,670	30,070	8.6%	317,600	91.4%
		Sell offers	44,154	168,816	43,617	25.8%	125,199	74.2%
Apr-23	Obligations	Buy bids	292,897	1,891,607	353,264	18.7%	1,538,343	81.3%
		Sell offers	187,316	808,030	123,689	15.3%	684,341	84.7%
	Options	Buy bids	8,798	191,005	17,436	9.1%	173,569	90.9%
		Sell offers	26,901	124,419	32,262	25.9%	92,157	74.1%
May-23	Obligations	Buy bids	164,671	1,212,827	259,343	21.4%	953,484	78.6%
		Sell offers	84,083	416,787	68,629	16.5%	348,158	83.5%
	Options	Buy bids	319	5,179	1,058	20.4%	4,121	79.6%
		Sell offers	12,449	61,591	26,777	43.5%	34,813	56.5%
2021/2022*	Obligations	Buy bids	5,524,001	24,606,901	5,426,331	22.1%	19,180,571	77.9%
		Sell offers	3,662,125	13,289,542	2,601,701	19.6%	10,687,841	80.4%
	Options	Buy bids	172,879	4,370,065	259,467	5.9%	4,110,598	94.1%
		Sell offers	364,911	2,313,988	551,119	23.8%	1,762,869	76.2%
2022/2023**	Obligations	Buy bids	6,353,931	36,241,441	6,882,738	19.0%	29,358,703	81.0%
		Sell offers	4,888,287	19,672,001	2,840,942	14.4%	16,831,060	85.6%
	Options	Buy bids	401,355	4,803,062	420,502	8.8%	4,382,560	91.2%
		Sell offers	818,125	2,554,130	642,080	25.1%	1,912,050	74.9%

* Shows 12 months for 2021/2022 ** Shows 12 months for 2022/2023

32 The term obligation is used only to distinguish FTRs from options.

Figure 13-6 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The prompt month is the final month for which FTRs for a specific month are sold. For example, June is the prompt month for June FTRs sold in the June auction, which occurs in May. The bid volume for the non-prompt months is significantly lower than for the prompt months. On average, the non-prompt month bid volume is 44.5 percent of the prompt month bid volume.

Figure 13-6 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June 2022 through May 2023 Auction

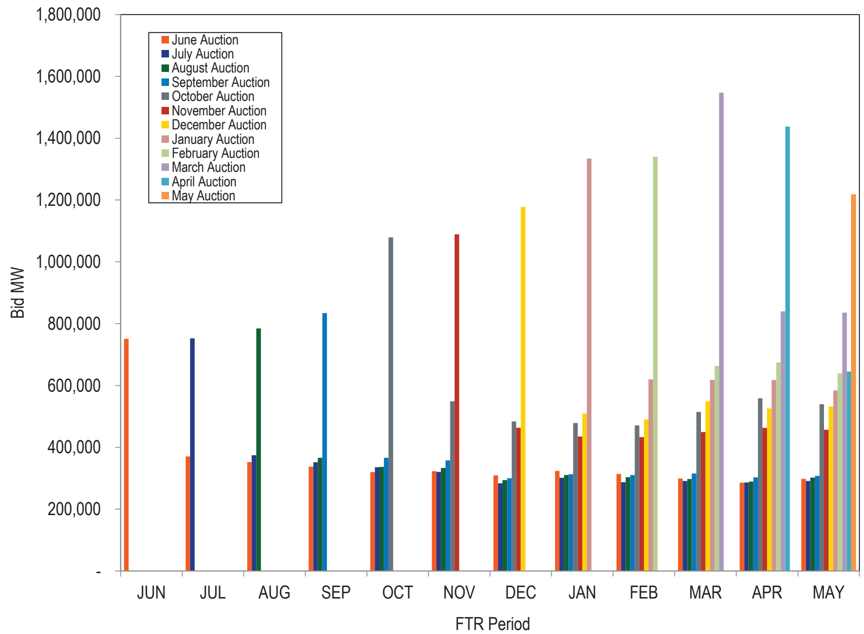


Figure 13-7 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt months cleared volume is 27.7 percent of the prompt month cleared volume.

Figure 13-7 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June 2022 through May 2023 Auction

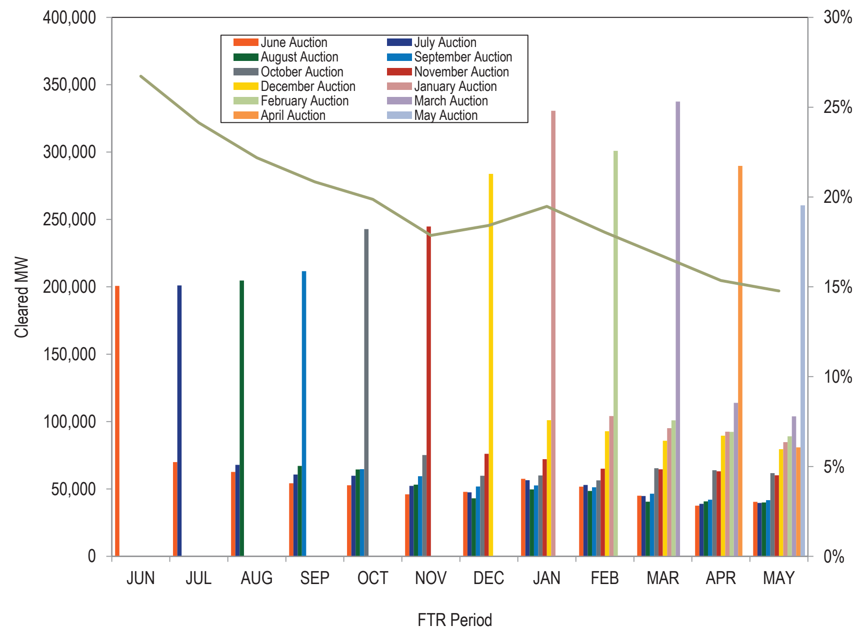


Figure 13-8 shows the FTR bid, net bid and cleared volume from June 2003 through May 2023 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. The cleared 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.

Figure 13-8 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through May 2023

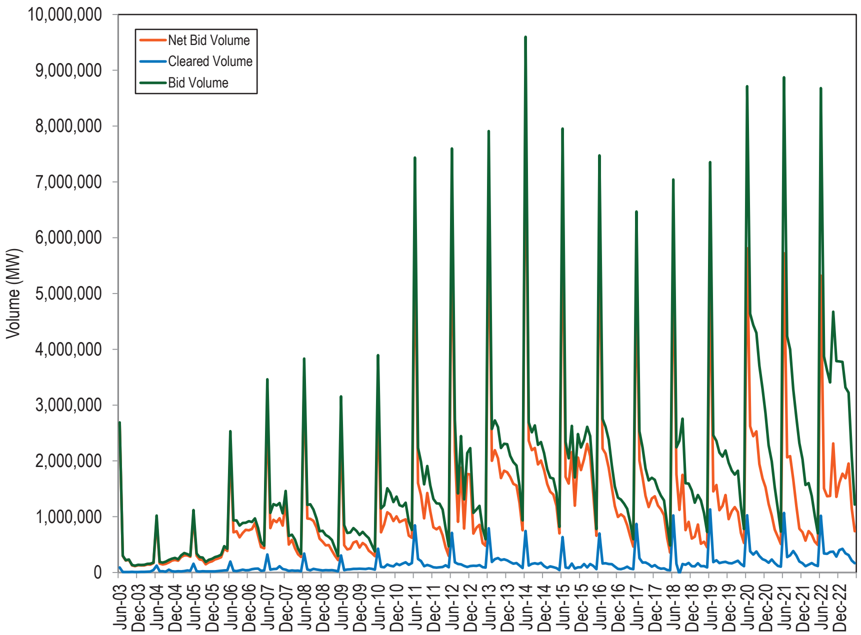
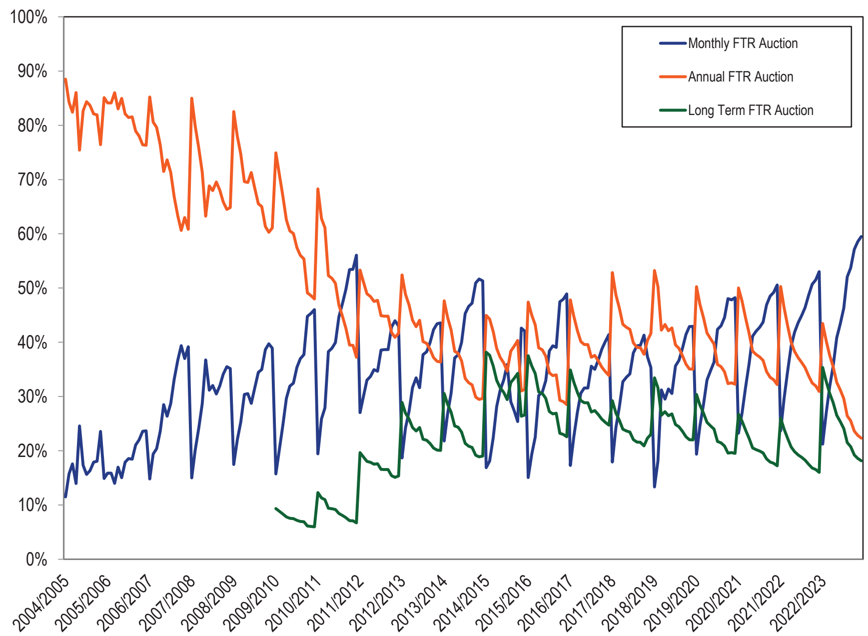


Figure 13-9 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through May 2023. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

Figure 13-9 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through May 2023



Bilateral Market

Table 13-25 provides the PJM registered secondary bilateral FTR market volume for the 2021/2022 and 2022/2023 planning periods. Bilateral FTR transactions registered through PJM do not need to include an accurate price or the entire volume of the transaction. Bilateral FTR transactions are not required to be registered through PJM. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

Table 13-25 Secondary bilateral FTR market volume: 2021/2022 and 2022/2023[33]

Planning Period	Type	Class Type	Volume (MW)
2021/2022	Obligation	24-Hour	6,275.4
		On Peak	99,564.8
		Off Peak	69,557.3
		Total	175,397.5
	Option	24-Hour	0.0
		On Peak	16,009.0
		Off Peak	20,846.6
		Total	36,855.6
2022/2023	Obligation	24-Hour	537.6
		On Peak	106.6
		Off Peak	184.4
		Total	828.6
	Option	24-Hour	50.0
		On Peak	0.0
		Off Peak	0.0
		Total	50.0

Price

Table 13-26 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2023/2026 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 -\$0.77 and \$0.90, compared to -\$0.50 and \$0.66 from the 2022/2025 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -\$0.83 and \$0.83, compared to -\$0.94 for counter flow FTRs and \$0.67 for prevailing flow FTRs.

33 The 2021/2022 planning period covers bilateral FTRs that are effective for any time between June 1, 2021 through May 31, 2022, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Table 13-26 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): 2023/2026

			Class Type					
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Counter Flow	Year 1	($2.65)	($0.75)	($0.42)	($0.68)	($0.45)	($0.85)
		Year 2	($2.77)	($0.69)	($0.39)	($0.66)	($0.38)	($0.76)
		Year 3	($2.22)	($0.64)	($0.31)	($0.58)	($0.33)	($0.63)
		Total	($2.61)	($0.71)	($0.38)	($0.65)	($0.40)	($0.77)
	Prevailing Flow	Year 1	$1.89	$0.97	$0.63	$0.89	$0.59	$0.94
		Year 2	$2.27	$0.88	$0.57	$0.85	$0.61	$0.94
		Year 3	$2.16	$0.71	$0.47	$0.73	$0.57	$0.77
		Total	$2.06	$0.87	$0.57	$0.84	$0.59	$0.90
	Total		($0.01)	$0.16	$0.11	$0.15	$0.13	$0.13
Sell offers	Counter Flow	Year 1	($1.91)	($1.15)	($0.76)	($0.92)	($0.54)	($0.98)
		Year 2	($2.33)	($0.64)	($0.31)	($0.49)	($0.35)	($0.55)
		Year 3	($4.54)	($0.40)	($0.39)	($0.35)	($0.18)	($0.42)
		Total	($2.05)	($0.97)	($0.59)	($0.75)	($0.46)	($0.83)
	Prevailing Flow	Year 1	$3.08	$0.96	$0.67	$0.76	$0.41	$0.86
		Year 2	$1.77	$0.89	$0.55	$0.82	$0.52	$0.78
		Year 3	$3.62	$0.63	$0.46	$0.63	$0.53	$0.69
		Total	$2.78	$0.92	$0.63	$0.77	$0.46	$0.83
	Total		$0.59	$0.20	$0.18	$0.12	$0.08	$0.18

Table 13-27 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 2023/2024 planning period. The weighted-average cleared buy bid price in the 2023/2024 Annual FTR Auction was $3.03 per MW, up from $1.22 per MW in the 2022/2023 planning period.

Table 13-27 Annual FTR Auction weighted-average cleared prices (Dollars per MW): 2023/2024

			Class Type				
Trade Type	Type	FTR Direction	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Obligations	Counter Flow	($1.12)	($0.42)	($0.35)	($0.21)	($0.39)
		Prevailing Flow	$1.65	$0.94	$0.72	$0.46	$0.86
		Total	$0.83	$0.37	$0.27	$0.14	$0.33
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.45	$0.61	$0.55	$0.35	$0.49
		Total	$0.45	$0.61	$0.55	$0.35	$0.49
Self-scheduled bids	Obligations	Counter Flow	($0.08)	($0.01)	$0.00	($0.03)	($0.02)
		Prevailing Flow	$3.47	$2.30	$1.42	$0.61	$3.37
		Total	$3.47	$2.28	$1.42	$0.60	$3.37
Buy and self-scheduled bids	Obligations	Counter Flow	($1.12)	($0.42)	($0.35)	($0.21)	($0.39)
		Prevailing Flow	$2.70	$0.95	$0.73	$0.46	$1.20
		Total	$2.12	$0.38	$0.27	$0.15	$0.59
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.45	$0.61	$0.55	$0.35	$0.49
		Total	$0.45	$0.61	$0.55	$0.35	$0.49
Sell offers	Obligations	Counter Flow	($2.57)	($0.92)	($0.83)	($0.55)	($1.05)
		Prevailing Flow	$2.45	$0.84	$0.75	$0.48	$0.86
		Total	($0.64)	$0.01	$0.05	$0.02	($0.06)
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.34	$0.73	$0.91	$0.62	$0.50
		Total	$0.34	$0.73	$0.91	$0.62	$0.50

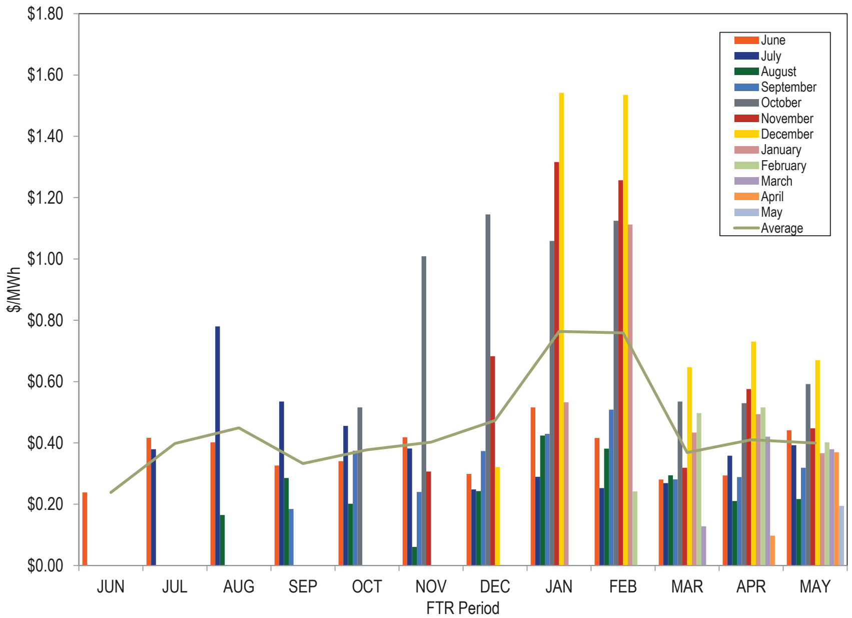
Table 13-28 shows the cleared buy bid volume, cleared buy bid revenue and cleared revenue/cleared MW for the last twelve planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative 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 2019/2020 planning period. Due to the more restrictive modeling for the 2022/2023 planning period (relative to the 2021/2022 planning period), quantities and revenue were similar to 2016/2017 levels, when PJM was restricting the FTR market to account for balancing congestion. The reassignment of balancing congestion and M2M payments to load did not increase the per MW value of ARRs. Following the high revenue from the 2022/2023 planning period, the 2023/2024 planning period cleared FTR buy bid volume increased by 75.9 percent. The combined result of the increase in cleared volume and relatively flat revenue was a decrease in the ARR per MW revenue of 50.1 percent compared to the 2022/2023 planning period.

Table 13-28 Cleared volume, revenue and $/MW: 2012/2013 through 2023/2024 Annual FTR Auction

	Buy Bid Volume	Cleared Buy Bid Volume	Percent Cleared	Buy Bid Revenue (millions)	Buy Bid Revenue ($/MW)
2012/2013	2,520,119	329,578	13.1%	$389.1	$1,181
2013/2014	3,245,033	391,148	12.1%	$382.5	$978
2014/2015	3,243,346	338,879	10.4%	$506.3	$1,494
2015/2016	2,437,964	354,630	14.5%	$620.5	$1,750
2016/2017	2,565,494	393,509	15.3%	$615.8	$1,565
2017/2018	2,281,534	488,734	21.4%	$406.5	$832
2018/2019	2,880,105	587,628	20.4%	$635.7	$1,082
2019/2020	2,787,716	611,878	21.9%	$649.0	$1,061
2020/2021	2,336,551	556,034	23.8%	$449.6	$809
2021/2022	2,043,408	535,277	26.2%	$519.0	$970
2022/2023	1,984,377	483,988	24.4%	$1,096.3	$2,265
2023/2024	3,746,935	851,248	22.7%	$957.9	$1,125

Figure 13-10 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the 2022/2023 planning period and the average price per MWh for each of the FTR periods.

Figure 13-10 Monthly Balance of Planning Period FTR Auction cleared weighted-average buy bid price per period (Dollars per MWh): 2022/2023 planning period



Profitability

FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to FTRs. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported prices reflect the actual prices under the PJM rules. Bilateral profits and losses net to zero in market total profits and losses. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Profits in the 2022/2023 planning period include the auction cost and revenue from both buying and selling FTRs that were effective between June 2022 and May 2023. This includes FTRs from the 2020/2023, 2021/2024 and 2022/2025 Long Term auctions, the 2022/2023 Annual auction, and the Monthly auctions from June 2022 through May 2023. The costs and revenues of the yearly FTR products are prorated based on the period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. The hourly revenues equal any positive hourly FTR target allocations, adjusted by the payout ratio plus any hourly auction revenues from the sale and/or the purchase of the FTR. The hourly auction costs equal any negative hourly FTR target allocations plus any hourly auction costs from the purchase and/or the sale of the FTR. The hourly auction costs and auction revenues are the product of the FTR MW and the auction price divided by the period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. The surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations for the current month or prior months in the planning period. A negative surplus (shortfall) at the end of the planning period is a deficiency that is charged as FTR uplift to FTR holders. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, after covering any shortfall in FTR target allocations within the planning period, the net surplus at the end of the planning period is distributed to ARR holders. Profits include any surplus distribution or uplift payments that was used to satisfy any shortfall in FTR target allocations.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every planning period from 2012/2013 through 2022/2023 except the 2016/2017 planning period, and were positive if summed over the entire period. Financial entities have been much more profitable than physical and physical ARR entities combined except for the 2015/2016 and the 2016/2017 planning periods (Table 13-31). It is not clear, in a competitive market, why FTR profits for financial entities remain persistently profitable and much more profitable than other participants. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-29 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction for the 2022/2023 planning period. All participants who were assigned ARRs are classified as physical ARR. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

In the 2022/2023 planning period, physical entities, including physical and physical ARR participants, lost $4.6 million on FTRs purchased directly (not self scheduled), down from $263.5 million in profits in the 2021/2022 planning period. Financial participants received $376.7 million in profits, down from $831.5 million in profits in the 2021/2022 planning period. Self scheduled FTRs have zero cost. ARR holders who self scheduled FTRs received $630.0 million in congestion revenues, up from $495.1 million in revenue in the 2021/2022 planning period. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits.

Table 13-29 FTR profits and revenues by organization type and FTR direction: 2022/2023

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$296,316,837	$80,403,690	$376,720,527			
Physical	($18,485,226)	$28,640,848	$10,155,622			
Physical ARR	$33,412,281	($48,206,726)	($14,794,445)	$621,209,232	$8,822,358	$630,031,590
Total	$311,243,892	$60,837,812	$372,081,704	$621,209,232	$8,822,358	$630,031,590

Table 13-30 lists the monthly FTR profits for the 2021/2022 planning period and the 2022/2023 planning period by organization type. In the 2022/2023 planning period, profits for all participants were $372.1 million, down from $1.1 billion in profits for the 2021/2022 planning period. The largest month to month decrease in profits was in January, $290.5 million, while March was the least profitable month with losses of $63.2 million. Among organization types, financial organizations had the largest decrease in profits, $454.8 million, or 54.7 percent, while physical organizations' profits decreased by $218.1 million, or 95.6 percent, and physical ARR organizations' profits decreased by $50.0 million, or 142.1 percent.

Table 13-30 Monthly FTR profits by organization type: 2021/2022 and 2022/2023

	Organization Type			
Month	Financial	Physical	Physical ARR	Total
Jun-21	$22,749,776	$10,606,339	($1,804,140)	$31,551,975
Jul-21	$8,954,231	$1,444,400	($2,291,232)	$8,107,399
Aug-21	$46,644,100	$6,599,865	($1,540,329)	$51,703,636
Sep-21	$34,557,289	$16,956,350	$1,899,307	$53,412,946
Oct-21	$31,270,038	$25,268,849	$11,751,068	$68,289,955
Nov-21	$116,821,607	$43,470,687	$24,301,446	$184,593,740
Dec-21	$51,669,759	$17,990,752	$5,025,774	$74,686,286
Jan-22	$194,692,701	$48,237,853	($736,180)	$242,194,374
Feb-22	$78,598,638	$3,939,750	$2,163,530	$84,701,917
Mar-22	$33,362,979	$4,158,572	($2,300,900)	$35,220,651
Apr-22	$69,598,243	$14,635,329	($1,740,487)	$82,493,085
May-22	$142,570,155	$34,980,452	$435,586	$177,986,193
Summary for Planning Period 2021/2022				
Total	$831,489,515	$228,289,196	$35,163,444	$1,094,942,155
Jun-22	$38,826,556	$32,051,827	$16,902,773	$87,781,157
Jul-22	$51,488,899	$5,584,937	($3,493,815)	$53,580,021
Aug-22	$85,347,316	$13,777,652	($4,086,437)	$95,038,531
Sep-22	$49,416,734	$21,771,486	$10,677,196	$81,865,416
Oct-22	$41,442,598	$6,066,363	$9,625,878	$57,134,840
Nov-22	$47,290,615	$8,598,279	$1,713,849	$57,602,743
Dec-22	$99,381,028	$7,281,468	$1,000,116	$107,662,612
Jan-23	($14,285,912)	($29,361,875)	($4,651,677)	($48,299,464)
Feb-23	$2,807,556	($29,424,384)	($9,499,237)	($36,116,066)
Mar-23	($32,140,699)	($14,961,039)	($16,068,780)	($63,170,517)
Apr-23	$17,549,913	($11,962,003)	($12,023,360)	($6,435,451)
May-23	($10,404,078)	$732,910	($4,890,951)	($14,562,119)
Summary for Planning Period 2022/2023				
Total	$376,720,527	$10,155,622	($14,794,445)	$372,081,704

Table 13-31 lists the historical profits by planning period by organization type beginning in the 2012/2013 planning period for purchased FTRs. (Profits do not include congestion revenue to self scheduled FTRs.) End of year surplus is allocated to ARR holders and end of year shortfalls are allocated to FTR holders as uplift. There was a $112.3 million end of year surplus in the 2018/2019 planning period; a $140.7 million end of year surplus in the 2019/2020 planning period; a $14.5 million end of year shortfall in the 2020/2021 planning period; a $29.5 million end of year shortfall in the 2021/2022 planning period; and a $235.2 million end of year surplus in the 2022/2023 planning period.

Table 13-31 FTR profits by organization type: 2012/2013 through 2022/2023

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$376,720,527
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918					
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$376,720,527
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$376,720,527
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918					
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$376,720,527
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$10,155,622
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618					
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$10,155,622
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	($14,794,445)
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635					
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186					
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	($14,794,445)
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442	($113,614,490)	$360,510,126	$1,094,942,155	$372,081,704

Table 13-32 shows the profits and losses of the five most and the five least profitable participants by patterns of ownership. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row considers all ownership types when selecting the Top 5 and Bottom 5 participants.

When all participants across ownership types are considered, four of the Top 5 participants and two of the Bottom 5 participants were financial participants. Of all the ownership types, the Top 5 physical ARR participants' share of profits was the highest, 95.6 percent, although the total profits of that group were the lowest. There are only a small number of physical ARR participants who directly purchase FTRs. Of all ownership types, the Bottom 5 financial participants' share of losses was the highest and their losses were the largest. Compared with other ownership types, financial organizations had many fewer unprofitable participants (Table 13-33). Overall, the five most profitable participants' profits and profit per MWh decreased and the five least profitable participants' losses and loss per MWh increased in the 2022/2023 planning period compared with the 2021/2022 planning period. Each organization type's top 5 participants' profits sum and average profit per MWh decreased. The Top 5 financial participants' profits had the largest decrease compared with the 2021/2022 planning period while their profit per MWh had the smallest decrease. The Top 5 physical participants had the largest profit per MWh decrease. Each organization type's bottom 5 participants' average loss per MWh increased. The Bottom 5 financial participants' losses and loss per MWh had the largest change. Financial participants were the only organization type that had an increase in the bottom 5 loss share. There was one financial participant who had big losses in January and in February and whose monthly losses were similar to or greater than the market total losses. There are participants who have had persistent losses for multiple years. It is possible for PJM FTR participants to have complementary positions in other trading platforms such as the Intercontinental Exchange (ICE) or Nodal Exchange.

Table 13-32 Top 5 and bottom 5 FTR profits by ownership type: 2022/2023

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	3,573,644,370	$221,472,612	$0.30	21.0%	39.4%	($154,142,197)	($0.62)	6.9%	83.1%
Physical	550,140,874	$89,572,793	$0.55	29.8%	61.2%	($86,056,523)	($1.05)	14.9%	63.2%
Physical ARR	387,307,589	$55,907,491	$0.29	50.3%	95.6%	($43,197,970)	($0.42)	26.5%	58.9%
All	4,511,092,834	$235,380,468	$0.30	17.5%	30.7%	($189,296,264)	($0.83)	5.1%	47.9%

Table 13-33 shows the shares of the number of profitable and unprofitable participants by ownership type weighted by FTR MWh in the 2022/2023 planning period. All ownership types had more profitable participants than unprofitable participants. Compared to the 2021/2022 planning period, the share of the profitable participants increased by 0.8 percent from 78.2 percent to 79.0 percent. The share of the profitable participants increased for financial and physical ARR organization types. In the 2022/2023 planning period, there were similar share of profitable participants but the sum of all the profits in the 2022/2023 planning period were 47.9 percent of the 2021/2022 planning period. In other words, profits were less concentrated in the 2022/2023 planning period than in the 2021/2022 planning period.

Table 13-33 Share of participants by profitability by ownership type: 2022/2023

Organization Type	Unprofitable	Profitable
Financial	16.3%	83.7%
Physical	39.4%	60.6%
Physical ARR	38.4%	61.6%
Total	21.0%	79.0%

Table 13-34 shows the profits by source and sink node type in the 2022/2023 planning period. The sink total row is the sum of all profits and losses of FTRs that have the same sink node type. The source total column is the sum of all profits and losses of FTRs that have the same source node type. The profits of generator to generator FTRs were the largest, $207.3 million, 55.7 percent of the total profits. In the 2021/2022 planning period, profits of generator to generator FTRs were 34.4 percent of the total profits. The losses of hub to zone FTRs were the largest, -$86.0 million. The profits of hub to hub FTRs decreased the most, by $170.2 million, compared with the 2021/2022 planning period.

Table 13-34 Profits by node type matrix: 2022/2023

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$8,717,428	$470,621	$42,852,918	$112,348	$2,567,509	$218,746	$2,691,284	$5,217,332	$62,848,185
EHVAGG	($18,248)	$70,096	$140,041	($27,351)	($9,363)	($1,036,277)	($21,200)	$205,684	($696,617)
Generator	$53,578,302	$2,799,005	$207,263,853	($9,142,105)	$17,732,811	$10,188,707	$19,676,742	($16,351,111)	$285,746,204
Hub	($11,677,045)	$14,503	($3,975,565)	($13,168,463)	($3,941,282)	($69,952)	($1,844,430)	($85,974,197)	($120,636,431)
Interface	($115,238)	$789	$1,226,169	($88,186)	($289,723)	$55,880	$341,191	$724,761	$1,855,642
Load	$1,823,255	$2,435,398	($837,369)	($396,961)	$397,797	$50,782,895	$187,261	($1,182,820)	$53,209,456
Residual Metered Aggregate	$726,155	$26,763	($5,786,123)	$423,686	($218,135)	$66,552	($4,521)	($185,137)	($4,950,760)
Zone	$1,268,832	$1,300	($16,013,346)	$100,884,661	($6,443,667)	$1,040,933	$2,416,935	$11,550,376	$94,706,024
Sink Total	$54,303,441	$5,818,476	$224,870,577	$78,597,628	$9,795,947	$61,247,485	$23,443,263	($85,995,112)	$372,081,704

Table 13-35 shows the profit per MWh by source and sink node type in the 2022/2023 planning period. The sink total row represents the average profit per MWh of FTRs that have the same sink type. The source total column shows the average profit per MWh of FTRs that have the same source type. Aggregate to EHV aggregate FTRs had the highest profit per MWh, $1.29 per MWh. Interface to interface FTRs had the largest loss per MWh, -$1.41 per MWh. Profit per MWh of generator to generator FTRs was $0.10 per MWh which is greater than market average, $0.08 per MWh.

Table 13-35 Profit per MWh by node type matrix: 2022/2023

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$0.21	$1.29	$0.22	$0.02	$0.57	$0.03	$0.15	$0.31	$0.22
EHVAGG	($0.04)	$0.02	$0.05	($0.46)	($0.20)	($0.10)	($0.24)	$1.30	($0.04)
Generator	$0.19	$0.70	$0.10	($0.07)	$0.54	$0.12	$0.40	($0.06)	$0.10
Hub	($0.92)	$0.34	($0.21)	($0.16)	($0.76)	($0.22)	($0.04)	($0.43)	($0.32)
Interface	($0.08)	$0.14	$0.15	($0.08)	($1.41)	$0.25	$0.57	$0.34	$0.13
Load	$0.27	$0.56	($0.01)	($0.89)	$0.78	$0.11	$0.11	($0.89)	$0.10
Residual Metered Aggregate	$0.21	$0.86	($0.19)	$0.44	($1.03)	$0.05	($0.00)	($0.09)	($0.12)
Zone	$0.07	$0.18	($0.35)	$1.27	($0.91)	$1.05	$0.04	$0.09	$0.28
Sink Total	$0.15	$0.48	$0.09	$0.27	$0.19	$0.11	$0.13	($0.13)	$0.08

Revenue

Long Term FTR Auction Revenue

Table 13-36 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2023/2026 Long Term FTR Auction netted $184.6 million in revenue, $111.8 million more (153.7 percent) than the previous Long Term FTR Auction. Buyers paid $249.2 million and sellers received $64.6 million, up $150.9 million (153.4 percent) and up $39.1 million (152.8 percent) over the previous Long Term FTR Auction.

Table 13-36 Long Term FTR Auction Revenue: 2023/2026

			Class Type					
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Counter Flow	Year 1	($122,693,970)	($146,716,823)	($28,770,689)	($30,105,394)	($30,706,828)	($358,993,703)
		Year 2	($57,998,003)	($76,147,379)	($15,890,893)	($16,514,789)	($15,357,812)	($181,908,875)
		Year 3	($30,906,794)	($59,994,640)	($11,506,524)	($13,469,208)	($12,002,562)	($127,879,727)
		Total	($211,598,766)	($282,858,841)	($56,168,106)	($60,089,391)	($58,067,201)	($668,782,306)
	Prevailing Flow	Year 1	$91,122,887	$218,616,547	$42,223,832	$46,399,555	$49,321,444	$447,684,265
		Year 2	$71,429,435	$119,968,664	$25,358,039	$25,080,089	$26,637,330	$268,473,558
		Year 3	$48,021,733	$89,073,624	$21,835,290	$19,548,610	$23,329,052	$201,808,310
		Total	$210,574,056	$427,658,836	$89,417,161	$91,028,253	$99,287,826	$917,966,132
	Total		($1,024,711)	$144,799,994	$33,249,055	$30,938,862	$41,220,625	$249,183,826
Sell offers	Counter Flow	Year 1	($8,754,761)	($51,800,291)	($11,930,218)	($9,638,715)	($9,416,603)	($91,540,588)
		Year 2	($2,627,201)	($13,190,415)	($2,995,194)	($2,513,461)	($2,562,031)	($23,888,302)
		Year 3	($588,030)	($1,186,001)	($24,767)	($419,597)	($300,740)	($2,519,135)
		Total	($11,969,992)	($66,176,707)	($14,950,178)	($12,571,773)	($12,279,374)	($117,948,025)
	Prevailing Flow	Year 1	$14,757,319	$67,397,597	$19,362,017	$10,497,614	$9,657,299	$121,671,846
		Year 2	$3,180,300	$29,840,915	$7,458,805	$5,391,384	$5,694,840	$51,566,245
		Year 3	$1,574,713	$4,220,970	$203,482	$1,231,849	$2,128,758	$9,359,772
		Total	$19,512,332	$101,459,483	$27,024,303	$17,120,847	$17,480,898	$182,597,863
	Total		$7,542,340	$35,282,775	$12,074,125	$4,549,074	$5,201,523	$64,649,838
Total			($8,567,051)	$109,517,219	$21,174,930	$26,389,788	$36,019,102	$184,533,988

Annual FTR Auction Revenue

Table 13-37 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2023/2024 planning period generated $1,694.3 million, up 12.8 percent from $1,501.5 million in the 2022/2023 planning period. Counter flow FTR holders received $237.9 million, up 11.2 percent from the previous planning period and prevailing flow FTR holders paid $1,932.2 million, up 12.6 percent from the previous planning period.

Table 13-37 Annual FTR auction revenue: 2023/2024

			Class Type				
Trade Type	Type	FTR Direction	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Obligations	Counter Flow	($70,311,178)	($192,496,265)	($59,567,129)	($64,141,728)	($386,516,300)
		Prevailing Flow	$247,591,907	$603,887,224	$166,778,107	$158,579,903	$1,176,837,142
		Total	$177,280,730	$411,390,959	$107,210,978	$94,438,175	$790,320,842
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$20,705,236	$73,614,724	$33,796,795	$39,423,028	$167,539,782
		Total	$20,705,236	$73,614,724	$33,796,795	$39,423,028	$167,539,782
	Total	Counter Flow	($70,311,178)	($192,496,265)	($59,567,129)	($64,141,728)	($386,516,300)
		Prevailing Flow	$268,297,143	$677,501,948	$200,574,902	$198,002,931	$1,344,376,924
		Total	$197,985,965	$485,005,683	$141,007,773	$133,861,203	$957,860,624
Self-scheduled bids	Obligations	Counter Flow	($430)	($386)	$0	($1,224)	($2,041)
		Prevailing Flow	$701,911,431	$13,754,533	$3,371,816	$1,967,656	$721,005,437
		Total	$701,911,001	$13,754,147	$3,371,816	$1,966,432	$721,003,396
Buy and self-scheduled bids	Obligations	Counter Flow	($70,311,608)	($192,496,652)	($59,567,129)	($64,142,952)	($386,518,341)
		Prevailing Flow	$949,503,339	$617,641,758	$170,149,923	$160,547,560	$1,897,842,579
		Total	$879,191,731	$425,145,106	$110,582,794	$96,404,607	$1,511,324,238
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$20,705,236	$73,614,724	$33,796,795	$39,423,028	$167,539,782
		Total	$20,705,236	$73,614,724	$33,796,795	$39,423,028	$167,539,782
	Total	Counter Flow	($70,311,608)	($192,496,652)	($59,567,129)	($64,142,952)	($386,518,341)
		Prevailing Flow	$970,208,575	$691,256,481	$203,946,718	$199,970,588	$2,065,382,361
		Total	$899,896,967	$498,759,830	$144,379,589	$135,827,635	$1,678,864,020
Sell offers	Obligations	Counter Flow	($52,770,060)	($58,436,171)	($18,669,208)	($18,694,951)	($148,570,389)
		Prevailing Flow	$31,333,096	$59,313,794	$20,967,643	$20,242,272	$131,856,805
		Total	($21,436,964)	$877,623	$2,298,435	$1,547,321	($16,713,585)
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$568,300	$519,005	$156,757	$77,164	$1,321,225
		Total	$568,300	$519,005	$156,757	$77,164	$1,321,225
	Total	Counter Flow	($52,770,060)	($58,436,171)	($18,669,208)	($18,694,951)	($148,570,389)
		Prevailing Flow	$31,901,395	$59,832,798	$21,124,400	$20,319,437	$133,178,030
		Total	($20,868,664)	$1,396,628	$2,455,192	$1,624,485	($15,392,359)
Total			$920,765,631	$497,363,202	$141,924,397	$134,203,150	$1,694,256,380

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTRs sold in Annual FTR Auctions. Table 13-38 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2023/2024 planning periods if long term FTRs were sold at annual auction clearing prices.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. But even this approach does not, and cannot, preserve all the capacity for ARR holders in the first year of the Long Term Auction. The system capacity purchased in the Long Term FTR Auction is made available to FTR holders before ARR holders have access to it. The result is that capacity is reserved, inappropriately and for unexplained reasons, in future auctions for FTR holders. This difference provides an 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 Auctions where it is the most valuable. Under the current market rules, capability made available in the Long Term FTR auction is not available to ARR holders as ARRs. The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should 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, and not projected residual system capability based on a snapshot of prior ARR requests.

Table 13-38 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
2020/2021	($416,585)	$52,736,819	($9,690,808)	$1,242,707	$43,872,132
2021/2022	$73,050,796	($3,111,721)	$13,856,264	NA	$83,795,339
2022/2023	$42,759,622	$62,664,762	$104,025,268	NA	$209,449,652
2023/2024	$45,464,085	$31,335,632	$39,140,382	NA	$115,940,099
Total	$354,449,064	$223,922,946	$349,458,091	$4,474,401	$816,364,404

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-39 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for the first five months of 2023. Beginning with the October 2022 Auction, Daily Off Peak and Weekend On Peak class types were introduced to replace the Off Peak Class type. The Monthly Balance of Planning Period FTR Auctions for the 2022/2023 planning period netted $106.0 million in revenue, the difference between buyers paying $711.0 million and sellers receiving $605.0 million. For the 2021/2022 planning period, the Monthly Balance of Planning Period FTR Auctions netted $50.3 million in revenue with buyers paying $412.5 million and sellers receiving $362.2 million. Revenue from obligation buy bids for the 2022/2023 planning period were up 68.7 percent over the same period last planning period. Revenue from obligation sell offers was up 70.9 percent over the same period last planning period.

Table 13-39 Monthly Balance of Planning Period FTR Auction revenue: January through May, 2023

			Class Type					
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	Daily Off Peak	Weekend On Peak	All
Jan-23	Obligations	Buy bids	$28,977,509	$16,759,220	$0	$8,759,706	$5,366,049	$59,862,484
		Sell offers	$2,027,458	$23,929,935	$0	$10,081,126	$7,129,486	$43,168,006
	Options	Buy bids	$608,659	$1,861,955	$0	$839,774	$470,996	$3,781,384
		Sell offers	$1,654,290	$7,118,929	$0	$3,661,808	$2,821,775	$15,256,802
Feb-23	Obligations	Buy bids	($401,711)	$14,435,461	$0	$7,738,678	$5,017,123	$26,789,551
		Sell offers	$2,986,371	$9,502,028	$0	$3,683,879	$2,600,461	$18,772,739
	Options	Buy bids	$390,690	$2,367,369	$0	$961,052	$632,551	$4,351,662
		Sell offers	$1,131,174	$3,764,493	$0	$1,812,244	$1,389,729	$8,097,639
Mar-23	Obligations	Buy bids	($9,527,625)	$15,541,144	$0	$6,945,264	$4,464,356	$17,423,138
		Sell offers	$2,749,686	$6,208,256	$0	$598,070	$1,138,660	$10,694,672
	Options	Buy bids	$134,878	$1,233,783	$0	$705,066	$517,472	$2,591,199
		Sell offers	$872,541	$2,803,604	$0	$1,242,208	$1,129,135	$6,047,487
Apr-23	Obligations	Buy bids	($2,667,402)	$6,723,289	$0	$2,754,100	$2,209,372	$9,019,359
		Sell offers	$646,565	$2,743,721	$0	$663,977	$855,464	$4,909,727
	Options	Buy bids	$0	$397,925	$0	$236,249	$158,390	$792,564
		Sell offers	$380,335	$1,614,066	$0	$626,793	$541,411	$3,162,605
May-23	Obligations	Buy bids	$1,350,577	$4,452,318	$0	$1,001,864	$731,431	$7,536,190
		Sell offers	$264,340	$2,286,098	$0	$479,524	$254,552	$3,284,514
	Options	Buy bids	$5,154	$16,974	$0	$6,596	$3,285	$32,008
		Sell offers	$322,181	$1,063,612	$0	$492,917	$369,143	$2,247,853
2021/2022*	Obligations	Buy bids	$130,170,799	$93,071,867	$154,936,269	$0	$0	$378,178,935
		Sell offers	$8,296,880	$98,421,764	$155,017,657	$0	$0	$261,736,301
	Options	Buy bids	$2,675,547	$14,067,533	$17,605,969	$0	$0	$34,349,049
		Sell offers	$19,136,817	$36,088,621	$45,266,394	$0	$0	$100,491,832
	Net Total		$105,412,649	($27,370,984)	($27,741,813)	$0	$0	$50,299,852
2022/2023**	Obligations	Buy bids	$141,883,115.95	$322,566,745	$85,220,313	$46,952,363	$41,223,002	$637,845,539
		Sell offers	$37,123,956	$272,251,385	$66,590,742	$37,712,941	$33,708,632	$447,387,657
	Options	Buy bids	$5,486,352	$35,517,408	$20,029,176	$7,545,100	$4,529,167	$73,107,203
		Sell offers	$14,353,203	$82,388,050	$24,685,222	$19,057,397	$17,115,311	$157,599,183
	Net Total		$95,892,309	$3,444,717	$13,973,526	($2,272,875)	($5,071,774)	$105,965,902

* Shows twelve months for 2021/2022 **Shows twelve months for 2022/2023

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 13-11 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the 2022/2023 planning period. The top 10 sinks that produced financial benefit accounted for 24.9 percent of total positive target allocations with the Western Hub accounting for 8.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 18.0 percent of total negative target allocations with PECO accounting for 4.3 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: 2022/2023

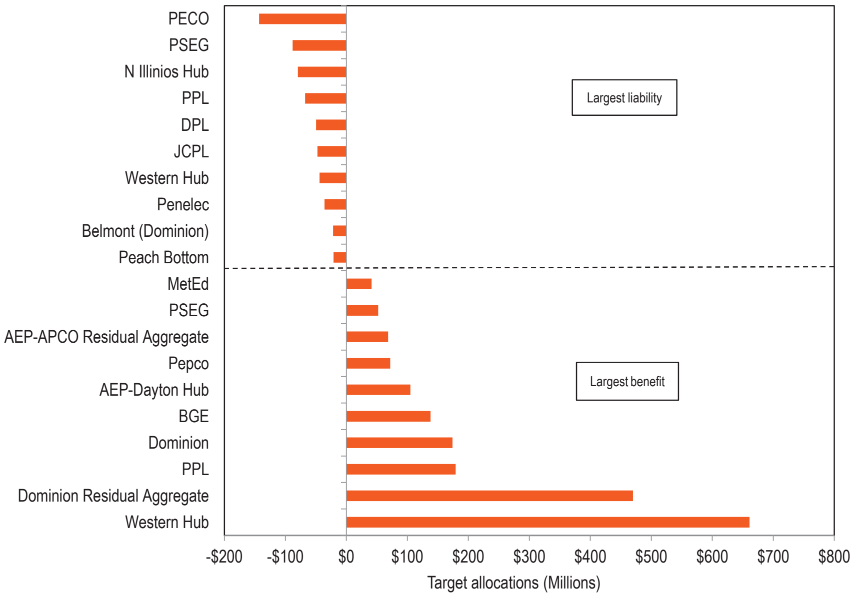


Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: 2022/2023

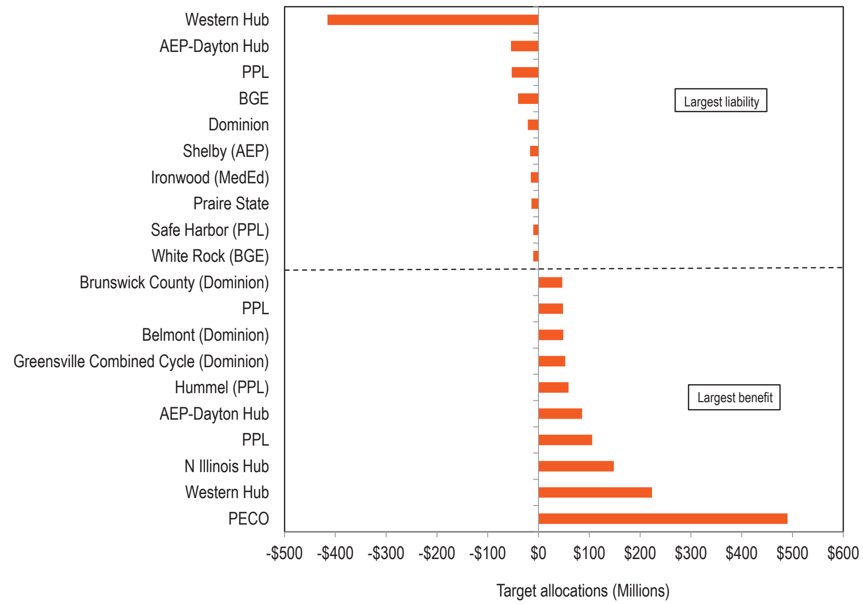


Figure 13-12 shows the 10 largest positive and negative FTR target allocations, summed by source, for the 2022/2023 planning period. The top 10 sources with a positive target allocation accounted for 16.6 percent of total positive target allocations with PECO accounting for 6.2 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 19.6 percent of all negative target allocations, with the Western Hub accounting for 12.5 percent of total negative target allocations.

The Effect of Fast Start Pricing on FTR Target Allocations

PJM implemented fast start pricing on September 1, 2021, and as a result, PJM produces separate dispatch and pricing market solutions. The dispatch run results in dispatch instructions and matching prices, termed dispatch run locational marginal prices, or DLMP. The DLMP prices are the prices that would have been the LMPs prior to fast start pricing. The pricing run results in the final prices used in settlements and for FTR target allocations, termed pricing run locational marginal prices, or PLMP. The two runs result in different sets of target allocations for the same FTR paths. Table 13-40 compares the target allocations that result from the pricing and dispatch runs for both self scheduled and all other FTRs for the 2021/2022 and 2022/2023 planning periods. The difference indicates whether the target allocations were increased or decreased as a result of fast start pricing.

Table 13-40 Pricing run and dispatch run FTR Target Allocations: 2021/2022 and 2022/2023 planning periods

Planning Period		Pricing Run	Dispatch Run	Difference	Percent Difference
2021/2022*	Not Self Scheduled	$1,499,077,738.2	$1,497,963,894.6	$1,113,843.6	0.1%
	Self Scheduled	$429,271,338.2	$430,800,597.9	($1,529,259.7)	(0.4%)
	Total	$1,928,349,076.4	$1,928,764,492.5	($415,416.1)	(0.0%)
2022/2023	Not Self Scheduled	$1,641,324,421.1	$1,586,284,501.9	$55,039,919.2	3.4%
	Self Scheduled	$622,535,801.9	$668,468,552.5	($45,932,750.6)	(7.4%)
	Total	$2,263,860,222.9	$2,254,753,054.3	$9,107,168.6	0.4%

* starting in September 2021

Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. In fact, there is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason and should be settled monthly.

Surplus day-ahead congestion is defined as the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[34] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[35] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus is distributed to ARR holders.[36]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-13 shows the distribution of the monthly surplus congestion revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning period, if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus congestion in that month to make FTRs whole. For example, September 2020 did not have enough surplus congestion to make FTRs whole. Those FTRs were made whole using surplus revenue from previous months. Three months of the 2022/2023 planning period did not have enough revenue to pay FTR target allocations, represented by lines that are entirely above the surplus bars. In the 2022/2023 planning

34 Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day-ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

35 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 31 (Feb. 23 2023).

36 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

period, $272.7 million was paid from individual monthly surplus amounts to cover shortfalls in months with a shortfall.

The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. 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. In Figure 13-13 the amount represented by each bar would be assigned to ARR holders in every month. In the 2022/2023 planning period, $116.7 million of surplus congestion revenue was paid to FTR holders that would have been paid to ARR holders under the MMU recommendation. Day-ahead congestion increased by $170.9 million, 8.3 percent, from $2,052.6 million in the 2021/2022 planning period to $2,223.5 million in the 2022/2023. Target allocations increased by $26.9 million, 1.2 percent, from $2,250.6 million in the 2021/2022 planning period to $2,277.5 million in the 2022/2023 planning period. This disconnect between target allocations and congestion is a result of incorrectly defined property rights in the current ARR/FTR market design.

Figure 13-13 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through May 2023[37]

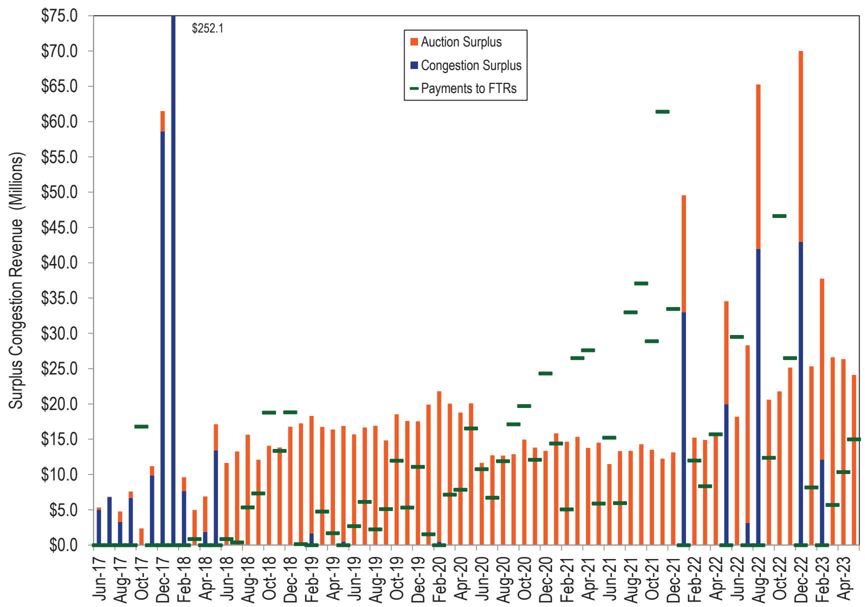


Figure 13-14 shows the surplus FTR auction revenue from the 2011/2012 planning period through the 2022/2023 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly

37 The bar for January 2018 is truncated.

and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-14 Monthly FTR auction surplus: 2011/2012 through 2022/2023

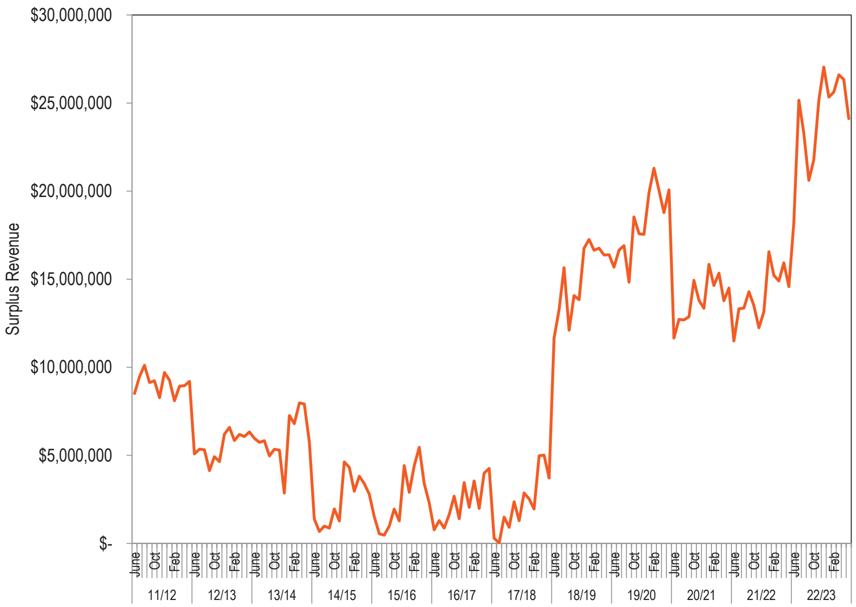


Table 13-41 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the 2022/2023 planning period.

Table 13-41 Surplus FTR Auction Revenue: 2010/2011 through 2022/2023[38]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021	$166.1	($185.1)	($14.5)
2021/2022	$168.5	$198.0	($29.5)
2022/2023	$289.2	$54.0	$235.2
Total	$1,413.4	($2,174.9)	($542.8)

*Start of counter flow "buy back"

38 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

Revenue Adequacy

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. If FTRs only returned congestion to FTR holders, there could be no such thing as revenue inadequacy.

As currently defined in PJM, FTR revenue adequacy simply compares congestion revenues to FTR target allocations. (Target allocations are the CLMP differences between the source and sink of the FTR times the MW of the FTR.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

Actual congestion revenues are not a result of PJM's decisions about the FTR auction model. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available system capability in the ARR/FTR market model through outage selection for the 2014/2015 through 2016/2017 planning periods resulted in a high level of revenue adequacy at the expense of a reduction in available ARRs and associated FTRs. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's actions have 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. Instead, 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. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. 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 in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. For that reason, ARRs have unsurprisingly been revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load, or even much less.

Total net FTR auction revenue for the 2021/2022 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $812.6 million. For the 2022/2023 planning period, total net FTR auction revenue was $1,664.2 million.

Table 13-42 presents the PJM FTR revenue detail for the 2021/2022 planning period and the 2022/2023 planning period. This includes 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.[39] 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. A negative deficiency is a surplus, which will be distributed to ARR holders at the end of the planning period, while a positive deficiency is a shortfall, which will be charged as FTR uplift at the end of the planning period.

Table 13-42 Total annual ARR and FTR revenue detail (Dollars (Millions)): 2021/2022 and 2022/2023

Accounting Element	2021/2022	2022/2023
ARR information		
ARR target allocations	$644.1	$1,375.0
ARR credits	$644.1	$1,375.0
FTR auction revenue	$812.6	$1,664.2
Annual FTR Auction net revenue	$692.4	$1,501.5
Long Term FTR Auction net revenue	$69.9	$56.8
Monthly Balance of Planning Period FTR Auction net revenue	$50.3	$106.0
Surplus auction revenue		
ARR Surplus	$168.5	$289.2
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$2,902.9	$2,791.2
Negative target allocations	($652.2)	($513.6)
FTR target allocations	$2,250.6	$2,277.5
Adjustments:		
Adjustments to FTR target allocations	$0.0	$0.0
Total FTR targets	$2,250.6	$2,277.5
FTR payout ratio	99.0%	100.0%
FTR revenues		
ARR excess	$168.5	$289.2
Congestion		
Net Negative Congestion (enter as negative)	$0.0	($0.0)
Hourly congestion revenue	$2,052.6	$2,223.5
M2M Payments(credit to PJM minus credit to M2M entity)	$0.0	$0.0
Adjustments:		
Surplus revenues carried forward into future months	$3.6	$0.0
Surplus revenues distributed back to previous months	$97.9	$37.5
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Surplus revenues distributed to other months	$101.5	$37.5
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$2,221.1	$2,277.5
Total congestion credits(includes end of year distribution)	$2,221.1	$2,277.5
Remaining deficiency	$29.5	($235.2)

39 The final ARR values may change if load shifts.

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-43 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month for the 2021/2022 planning period and the 2022/20023 planning period.

The total row in Table 13-43 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-43 Monthly FTR accounting summary (Dollars (Millions)): 2021/2022 and 2022/2023

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus (with adjustments)	Monthly Credits Deficiency (with adjustments)
Jun-21	$97.7	$101.5	96.3%	$101.5	100.0%	$0.0	$0.0
Jul-21	$86.5	$79.1	100.0%	$86.5	100.0%	$7.4	$0.0
Aug-21	$121.5	$141.1	86.1%	$141.1	100.0%	$0.0	$0.0
Sep-21	$110.7	$133.5	82.9%	$133.5	100.0%	$0.0	$0.0
Oct-21	$126.7	$142.1	89.2%	$142.1	100.0%	$0.0	$0.0
Nov-21	$220.9	$270.1	81.8%	$260.9	96.6%	$0.0	($44.0)
Dec-21	$126.1	$146.4	86.1%	$126.1	86.1%	$0.0	($20.3)
Jan-22	$459.8	$410.2	100.0%	$459.6	100.0%	$49.6	$0.0
Feb-22	$174.1	$170.9	100.0%	$174.1	100.0%	$3.2	$0.0
Mar-22	$114.2	$107.6	100.0%	$114.2	100.0%	$6.6	$0.0
Apr-22	$161.9	$161.6	100.0%	$161.9	100.0%	$0.2	$0.0
May-22	$421.0	$386.4	100.0%	$421.0	100.0%	$34.5	$0.0
		Summary for Planning Period 2021/2022					
Total	$2,221.1	$2,250.6		$2,322.3			($29.5)
Jun-22	$220.2	$231.5	95.1%	$231.5	100.0%	$0.0	$0.0
Jul-22	$248.7	$220.4	100.0%	$248.7	100.0%	$28.3	$0.0
Aug-22	$378.9	$313.7	100.0%	$378.9	100.0%	$65.3	$0.0
Sep-22	$269.1	$260.9	100.0%	$269.1	100.0%	$8.2	$0.0
Oct-22	$183.2	$208.0	88.1%	$208.0	100.0%	$0.0	$0.0
Nov-22	$240.4	$241.8	99.4%	$241.8	100.0%	$0.0	$0.0
Dec-22	$392.0	$322.1	100.0%	$392.0	100.0%	$70.0	$0.0
Jan-23	$94.6	$77.5	100.0%	$94.6	100.0%	$17.2	$0.0
Feb-23	$128.4	$90.7	100.0%	$128.4	100.0%	$37.7	$0.0
Mar-23	$80.8	$59.9	100.0%	$80.8	100.0%	$20.9	$0.0
Apr-23	$155.2	$139.3	100.0%	$139.3	100.0%	$16.0	$0.0
May-23	$121.1	$111.9	100.0%	$111.9	100.0%	$9.1	$0.0
		Summary for Planning Period 2022/2023					
Total	$2,512.8	$2,277.5		$2,525.2		$235.2	

Figure 13-15 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through May 2023. 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 13-15 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for months with a payout ratio less than 100 percent in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period and assigned to prior months.

Figure 13-15 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through May 2023

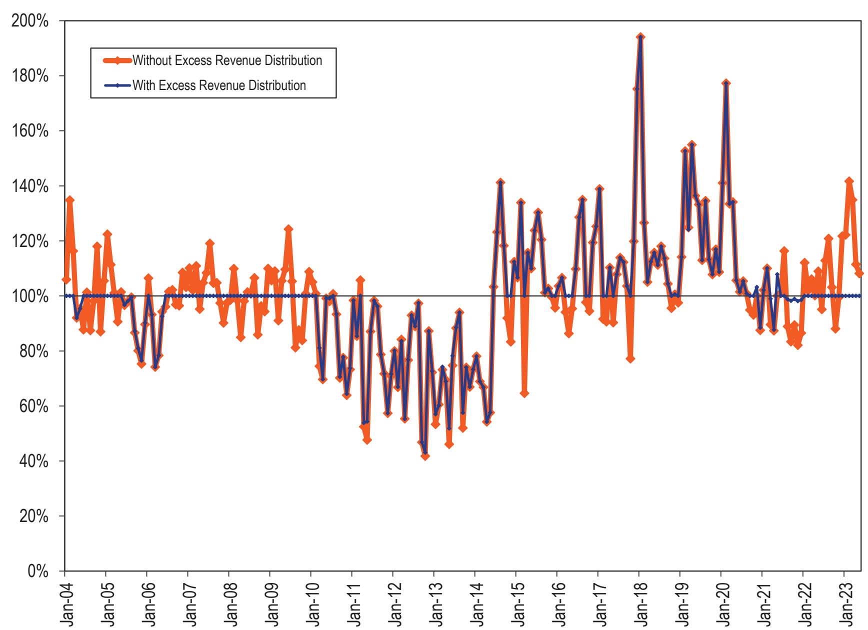


Table 13-44 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. The 2013/2014 planning period includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

The 2022/2023 planning period had a payout ratio of 100.0 percent.

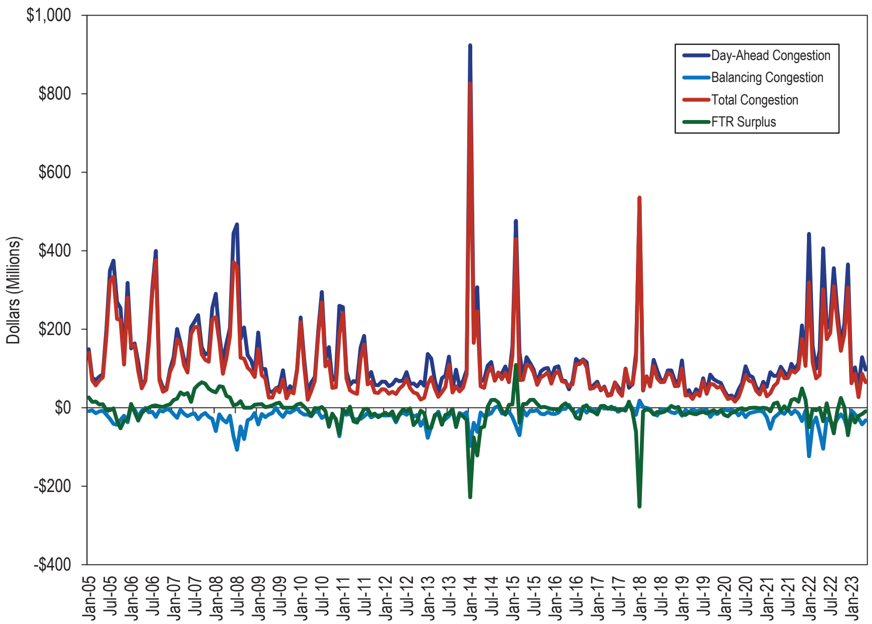
Table 13-44 Reported FTR payout ratio by planning period[40]

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	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	98.7%
2021/2022	99.0%
2022/2023	100.0%

40 The actual payout ratios for the 2006/2007, 2007/2008, and 2008/2009 planning periods may have exceeded 100 percent.

Figure 13-16 shows the day-ahead balancing and total congestion payments from 2005 through May 2023.

Figure 13-16 FTR surplus and day-ahead, balancing and total congestion: 2005 through May 2023



Target Allocations and Congestion by Constraint

One of the reasons that the current path based ARR/FTR market design does not provide a reasonable way to return congestion to load is because target allocations on the FTR paths do not align with congestion based on actual network use. A comparison of the FTR target allocations for individual constraints to the day-ahead and total congestion by constraint provides evidence of this misalignment. Total congestion is the sum of day-ahead and balancing congestion. If FTR target allocations on some paths are significantly greater than actual congestion and FTR target allocations on other paths are significantly less than actual congestion, this is evidence of a serious flaw in the design. It is evidence that the FTR design is not meeting its goal of paying out congestion, regardless of the recipients.

FTR target allocations are the result of constraints on day-ahead paths in the energy market. Any specific FTR path may be affected by multiple constraints. Constraints that result in FTR target allocations greater than the congestion that results from those constraints mean that the FTR target allocations are greater than the actual congestion. Figure 13-17 shows the constraints that are the top 10 sources of positive FTR target allocations, for the 2022/2023 planning period. Figure 13-17 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints.

Figure 13-17 Top ten constraint sources of positive FTR target allocations: June 2022 through May 2023

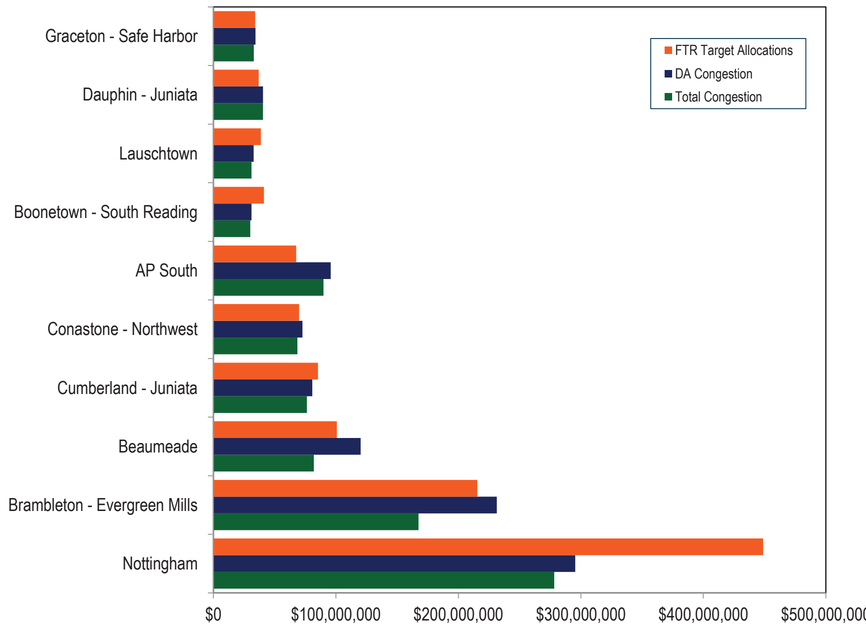


Figure 13-18 shows the constraints that are the top 10 sources of negative FTR target allocations, for the 2022/2023 planning period. Figure 13-18 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraint.

In the 2022/2023 planning period, there were 53 constraints that were the source of negative target allocations. Of the 53 constraints with negative target allocations, 49 resulted in positive actual total congestion. Constraints that contribute positive congestion revenues and have negative FTR target allocations are a source of funds used in the settlement process to pay for FTR target allocations on FTR paths that are over allocated relative to actual congestion.

Figure 13-18 Top ten constraint sources of negative FTR target allocations: June 2022 through May 2023

ARRs as an Offset to Congestion for Load

Load pays 100 percent of congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-45 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. The highlighted offsets are the actual offsets based on the rules that were effective 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 day-ahead congestion and the load share of balancing and M2M payments.

Total ARR and self scheduled FTR revenue offset 78.8 percent of total congestion costs for the 2022/2023 planning period.

Table 13-45 ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2022/2023

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022	$469.7	$500.5	$2,069.2	($457.4)	$1,611.8	($104.6)	($2.9)	($2.9)	$865.6	53.7%	$509.9	31.6%	$509.9	31.6%	$509.9	31.6%
2022/2023	$998.7	$630.0	$2,223.5	($526.5)	$1,697.1	($80.6)	$65.1	$235.2	$1,548.2	91.2%	$1,167.4	68.8%	$1,337.5	78.8%	$1,337.5	78.8%
Total	$6,358.5	$3,656.9	$15,730.8	($3,228.5)	$12,502.2	($406.5)	$375.1	$1,768.5	$9,608.9	76.9%	$7,162.0	57.3%	$8,555.4	68.4%	$8,683.6	69.5%

Table 13-45 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

Table 13-46 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for the planning period and prior planning periods.

From the 2011/2012 planning period through the 2022/2023 planning period, the cumulative offset, the cumulative return of congestion to load, was only 69.5 percent based on the total congestion and the effective offset rules that were in place for each planning period. Load has been underpaid by $3.8 billion from the 2011/2012 planning period through the 2022/2023 planning period.[41] This is an increase of $0.4 billion from the $3.4 billion that load had been underpaid for the 2011/2012 planning period through the 2021/2022 planning period. The $3.8 billion is the difference between the total congestion column ($12.5 billion) and the total offset column ($8.7 billion) in Table 13-45.

41 There was a $25.9 million dollar decrease in the shortfall compared to the previous Quarterly State of the Market Report. See *2023 Quarterly State of the Market Report for PJM: January through March*, Section 13: Financial Transmission and Auction Revenue Rights, ARRs as an Offset to Congestion for Load

Table 13-46 ARR and self scheduled FTR cumulative offset for ARR holders: 2011/2012 through 2022/2023

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	103.4%	$25.3
2012/2013	102.4%	$31.2
2013/2014	67.8%	($1,012.9)
2014/2015	66.7%	($1,498.3)
2015/2016	70.9%	($1,589.2)
2016/2017	75.0%	($1,556.9)
2017/2018	71.0%	($2,156.7)
2018/2019	72.7%	($2,215.4)
2019/2020	76.3%	($2,030.2)
2020/2021	74.4%	($2,357.2)
2021/2022	68.0%	($3,459.1)
2022/2023	69.5%	($3,818.7)

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no good reason that this should be the result of a system designed to return congestion to load. PJM has offered no explanation for this result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. The misalignment of path based ARR rights produces cross subsidies among ARR holders.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract 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, including generation in the zone and outside the zone.[42]

Table 13-47 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[43] The offset for the 2022/2023 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-47 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-47 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.

42 *See* "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.
43 See *2020 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses

Table 13-47 Zonal ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2022/2023 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$3.5	$0.1	($6.17)	$0.65	($1.9)	$22.4	($4.3)	($1.9)	$16.3	(11.8%)
AEP	$82.3	$95.8	($79.3)	$32.0	$130.9	$353.4	($55.5)	($23.8)	$274.1	47.7%
APS	$69.4	$29.5	($31.4)	$17.8	$85.3	$137.2	($22.3)	($9.1)	$105.8	80.6%
ATSI	$39.1	$0.8	($40.7)	$6.8	$6.0	$173.9	($28.3)	($12.4)	$133.1	4.5%
BGE	$146.4	$6.5	($19.4)	$26.0	$159.4	$87.8	($13.8)	($5.7)	$68.4	233.2%
COMED	$42.4	$0.0	($56.2)	$7.3	($6.5)	$238.7	($38.8)	($17.4)	$182.5	(3.5%)
DAY	$9.1	$1.0	($10.8)	$1.7	$1.0	$43.2	($7.6)	($3.2)	$32.4	3.1%
DOM	$51.6	$436.3	($85.5)	$8.3	$410.7	$355.6	($63.9)	($21.5)	$270.1	152.1%
DPL	$84.3	$8.1	($13.7)	$1.9	$80.7	$78.3	($10.2)	($3.4)	$64.6	124.9%
DUKE	$44.2	$7.1	($16.9)	$37.4	$71.9	$68.6	($11.9)	($4.9)	$51.7	139.0%
DUQ	$11.1	$0.2	($8.3)	$16.3	$19.3	$26.8	($5.8)	($2.5)	$18.5	104.6%
EKPC	$6.8	$0.1	($8.4)	$1.2	($0.3)	$35.5	($5.8)	($2.5)	$27.2	(1.1%)
EXT	$1.6	$0.0	($12.7)	$0.0	($11.1)	$41.6	($12.7)	$0.0	$28.9	(38.3%)
JCPLC	$7.6	$0.0	($16.3)	$1.3	($7.4)	$69.3	($12.1)	($4.2)	$53.0	(14.0%)
MEC	$46.7	$3.3	($11.2)	$8.6	$47.3	$43.7	($8.3)	($2.9)	$32.4	145.8%
OVEC	$0.0	$0.0	($0.5)	$0.0	($0.5)	$3.8	($0.5)	$0.0	$3.3	(15.4%)
PE	$19.2	$8.7	($10.8)	$4.9	$22.1	$46.1	($7.6)	($3.2)	$35.3	62.5%
PECO	$26.3	$12.5	($24.0)	$6.3	$21.2	$98.9	($16.7)	($7.3)	$74.9	28.3%
PEPCO	$71.9	$4.9	($17.9)	$13.1	$71.9	$78.9	($12.7)	($5.2)	$61.0	118.0%
PPL	$137.2	$11.8	($28.2)	$25.9	$146.6	$112.0	($20.6)	($7.6)	$83.7	175.1%
PSEG	$96.9	$3.3	($27.1)	$17.7	$90.8	$102.5	($19.0)	($8.1)	$75.4	120.5%
REC	$0.9	$0.0	($0.9)	$0.2	$0.1	$5.5	($0.7)	($0.3)	$4.5	2.4%
Total	$998.7	$630.0	($526.4)	$235.2	$1,337.5	$2,223.5	($379.3)	($147.2)	$1,697.1	78.8%

The total congestion offset paid to loads in the 2022/2023 planning period was 78.8 percent of congestion costs. 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 ATSI, 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.

The amount and proportion of the offset that can be realized by load serving entities via their ARR allocations varies by planning period. The offsets are a function of the assignment of ARRs relative actual network sources of congestion paid, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load that paid it. It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths.

Offset if all ARRs are Held as ARRs

Table 13-48 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARRs holders held all their allocated ARRs in the 2020/2021, 2021/2022, and the 2022/2023 planning periods and did not self schedule any.

Table 13-48 Offset available to load if all ARRs are held: 2020/2021 through 2022/2023 planning periods

	20/21 Planning Period				21/22 Planning Period				22/23 Planning Period			
	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset
ACEC	$4.4	($2.7)	$5.5	31.2%	$4.0	($5.2)	$14.8	(8.0%)	$3.8	($6.2)	$16.3	(14.6%)
AEP	$85.3	($38.1)	$110.9	42.6%	$84.2	($65.7)	$240.4	7.7%	$187.1	($79.3)	$274.1	39.3%
APS	$50.5	($14.8)	$45.2	79.0%	$43.3	($29.7)	$122.8	11.0%	$104.0	($31.4)	$105.8	68.6%
ATSI	$20.5	($19.5)	$50.6	2.1%	$26.3	($32.3)	$117.9	(5.1%)	$39.6	($40.7)	$133.1	(0.8%)
BGE	$61.1	($9.1)	$24.8	209.2%	$102.8	($17.0)	$59.9	143.2%	$151.5	($19.4)	$68.4	193.2%
COMED	$43.2	($28.5)	$78.3	18.8%	$43.0	($44.7)	$159.9	(1.1%)	$42.4	($56.2)	$182.5	(7.5%)
DAY	$6.4	($5.3)	$11.0	9.8%	$6.1	($8.6)	$26.2	(9.6%)	$9.9	($10.8)	$32.4	(2.7%)
DOM	$67.5	($37.9)	$87.9	33.7%	$87.1	($22.0)	$370.9	17.5%	$218.5	($85.5)	$270.1	49.3%
DPL	$32.8	($6.7)	$36.2	72.0%	$50.9	($80.3)	($21.1)	139.2%	$95.3	($13.7)	$64.6	126.3%
DUKE	$28.8	($8.4)	$17.4	117.5%	$27.8	($12.3)	$23.7	65.3%	$48.7	($16.9)	$51.7	61.5%
DUQ	$5.8	($4.0)	$6.2	28.7%	$6.7	($6.4)	$45.3	0.5%	$11.2	($8.3)	$18.5	15.8%
EKPC	$3.0	($4.2)	$8.4	(13.3%)	$3.9	($7.0)	$21.9	(14.2%)	$6.8	($8.4)	$27.2	(5.6%)
EXT	$0.5	($13.8)	$11.0	(120.7%)	$0.7	($9.9)	$19.9	(46.2%)	$0.0	($12.7)	$28.9	(43.8%)
JCPLC	$6.1	($6.1)	$12.9	(0.1%)	$2.1	($12.8)	$39.0	(27.4%)	$7.6	($16.3)	$53.0	(16.4%)
MEC	$3.9	($5.3)	$16.5	(8.4%)	$9.3	($11.6)	$33.2	(6.7%)	$50.1	($11.2)	$32.4	119.6%
OVEC	NA	($0.3)	$0.9	(28.8%)	NA	($0.4)	$1.5	(29.4%)	NA	($0.5)	$3.3	(15.4%)
PE	$9.3	($6.5)	$16.4	16.7%	$13.1	($18.5)	$31.8	(17.2%)	$28.5	($10.8)	$35.3	50.2%
PECO	$15.1	($10.9)	$24.9	17.0%	$21.5	($12.0)	$78.0	12.1%	$36.6	($24.0)	$74.9	16.8%
PEPCO	$29.1	($8.3)	$20.5	101.6%	$31.3	($15.5)	$53.8	29.3%	$76.3	($17.9)	$61.0	95.8%
PPL	$26.1	($11.5)	$30.8	47.4%	$37.7	($21.5)	$103.3	15.7%	$151.0	($28.2)	$83.7	146.6%
PSEG	$24.7	($13.9)	$25.0	43.2%	$35.3	($23.1)	$76.0	16.1%	$103.5	($27.1)	$75.4	101.4%
REC	$0.2	($0.6)	$2.1	(17.0%)	$0.3	($0.8)	$5.3	(9.5%)	$0.9	($0.9)	$4.5	(1.0%)
Total	$524.3	($256.2)	$643.4	41.7%	$637.1	($457.4)	$1,624.6	11.1%	$1,373.4	($526.4)	$1,697.1	49.9%

Offset if all ARRs are Self Scheduled

Table 13-49 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARR holders self scheduled all their ARRs received in the annual auction process as FTRs in the 2020/2021, 2021/2022, and the 2022/2023 planning periods. Market rules allow ARRs available in the annual auction process to be self scheduled as FTRs. Any ARRs awarded monthly as residual ARRs cannot be self scheduled but provide ARR revenue based on monthly auction results. The calculated self scheduled FTR target allocations assume a 100 percent payout ratio. The results show that the recovery of congestion varies significantly by zone and that the load in some zones recovers more than the congestion paid and the load in other zones recovers less. This result is not consistent with a rational FTR/ARR design under which all load would be returned their congestion, but no more and no less.

Table 13-49 Offset available to load if all ARRs self scheduled: 2020/2021 through 2022/2023 planning periods

	20/21 Planning Period					21/22 Planning Period					22/23 Planning Period				
	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+M2M	Offset
ACEC	$1.8	$0.3	($2.7)	$5.5	(11.1%)	$0.4	$0.1	($5.2)	$14.8	(31.4%)	$3.0	$0.0	($6.2)	$16.3	(19.6%)
AEP	$77.3	$1.2	($38.1)	$110.9	36.4%	$132.5	$0.5	($65.7)	$240.4	28.0%	$208.7	$1.0	($79.3)	$274.1	47.6%
APS	$42.0	$0.2	($14.8)	$45.2	60.7%	$93.3	$1.6	($29.7)	$122.8	53.1%	$70.4	$7.9	($31.4)	$105.8	44.3%
ATSI	$30.7	$0.0	($19.5)	$50.6	22.1%	$47.3	$0.0	($32.3)	$117.9	12.7%	$84.8	$0.7	($40.7)	$133.1	33.7%
BGE	$79.7	$0.2	($9.1)	$24.8	285.0%	$147.0	$0.1	($17.0)	$59.9	217.3%	$194.0	$0.0	($19.4)	$68.4	255.2%
COMED	$69.6	$0.0	($28.5)	$78.3	52.5%	$51.9	$0.2	($44.7)	$159.9	4.6%	$31.1	$0.5	($56.2)	$182.5	(13.5%)
DAY	$8.0	$0.0	($5.3)	$11.0	24.9%	$7.1	$0.2	($8.6)	$26.2	(4.7%)	$11.4	$0.0	($10.8)	$32.4	1.8%
DOM	$117.0	$1.6	($37.9)	$87.9	91.8%	$556.6	$11.5	($22.0)	$370.9	147.3%	$663.2	$19.2	($85.5)	$270.1	221.0%
DPL	$56.4	$5.7	($6.7)	$36.2	153.1%	$52.3	$2.9	($80.3)	($21.1)	119.3%	$56.2	$1.0	($13.7)	$64.6	67.3%
DUKE	$40.9	$0.0	($8.4)	$17.4	187.5%	$50.8	$0.7	($12.3)	$23.7	165.4%	$81.4	$0.0	($16.9)	$51.7	124.7%
DUQ	$8.9	$0.0	($4.0)	$6.2	79.7%	$7.0	$0.0	($6.4)	$45.3	1.2%	$15.0	$0.0	($8.3)	$18.5	36.5%
EKPC	$6.6	$0.0	($4.2)	$8.4	29.3%	$10.1	$0.0	($7.0)	$21.9	14.2%	$13.0	$0.0	($8.4)	$27.2	17.3%
EXT	$0.3	$0.0	($13.8)	$11.0	(122.3%)	$1.9	$0.0	($9.9)	$19.9	(40.0%)	NA	$0.0	($12.7)	$28.9	(43.8%)
JCPLC	$0.9	$0.0	($6.1)	$12.9	(40.1%)	$4.4	$0.0	($12.8)	$39.0	(21.7%)	$5.3	$0.0	($16.3)	$53.0	(20.8%)
MEC	$8.0	$0.0	($5.3)	$16.5	16.6%	$31.3	$0.0	($11.6)	$33.2	59.5%	$46.5	$0.0	($11.2)	$32.4	108.7%
OVEC	NA	$0.0	($0.3)	$0.9	(28.8%)	NA	$0.0	($0.4)	$1.5	(29.4%)	NA	$0.0	($0.5)	$3.3	(15.4%)
PE	$13.5	$0.0	($6.5)	$16.4	42.8%	$29.7	$0.1	($18.5)	$31.8	35.5%	$20.5	$0.2	($10.8)	$35.3	28.3%
PECO	$14.0	$0.3	($10.9)	$24.9	13.4%	$6.2	$0.8	($12.0)	$78.0	(6.5%)	$6.8	$0.0	($24.0)	$74.9	(22.8%)
PEPCO	$37.3	$0.0	($8.3)	$20.5	141.9%	$59.2	$0.0	($15.5)	$53.8	81.2%	$95.2	$0.0	($17.9)	$61.0	126.7%
PPL	$43.7	$1.3	($11.5)	$30.8	108.7%	$160.3	$0.0	($21.5)	$103.3	134.4%	$117.4	$0.0	($28.2)	$83.7	106.4%
PSEG	$43.2	$0.4	($13.9)	$25.0	118.4%	$94.0	$0.2	($23.1)	$76.0	93.4%	$48.7	$0.4	($27.1)	$75.4	29.1%
REC	$1.0	$0.0	($0.6)	$2.1	21.0%	$1.1	$0.0	($0.8)	$5.3	6.2%	$0.8	$0.0	($0.9)	$4.5	(4.2%)
Total	$700.9	$11.2	($256.2)	$643.4	70.9%	$1,544.3	$18.8	($457.4)	$1,624.6	68.1%	$1,773.4	$31.0	($526.4)	$1,697.1	75.3%

ARR Allocation and Congestion In and Out of Zone

Table 13-50 shows the share of ARR MW for the 2022/2023 planning period with paths that source inside and outside the zone where the ARR load is located, and the proportion of congestion that results from constraints that are inside and outside the zone. Table 13-50 allows a comparison of externally sourced ARRs with the congestion that results from external constraints. For example, 98.5 percent of ACEC congestion results from constraints that are outside of the zone, but only 31.7 percent of ACEC ARRs originate outside the zone.

Table 13-50 illustrates one of the fundamental issues with the path based approach to ARR/FTR design. In the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load, but the assignment of ARRs is inconsistent with that fact. This inconsistency makes it impossible for load to match ARRs with the actual sources of congestion.

Table 13-50 ARR Allocation and Congestion from inside and outside zone: 2022/2023

	ARRs		Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	31.7%	68.3%	98.5%	1.5%
AEP	8.7%	91.3%	90.9%	9.1%
APS	12.6%	87.4%	97.5%	2.5%
ATSI	25.1%	74.9%	98.7%	1.3%
BGE	37.4%	62.6%	91.3%	8.7%
COMED	0.0%	100.0%	93.5%	6.5%
DAY	75.9%	24.1%	99.9%	0.1%
DOM	0.1%	99.9%	75.9%	24.1%
DPL	27.1%	72.9%	74.3%	25.7%
DUKE	34.6%	65.4%	93.9%	6.1%
DUQ	77.7%	22.3%	99.8%	0.2%
EKPC	53.3%	46.7%	99.8%	0.2%
EXT	100.0%	0.0%	88.6%	11.4%
JCPL	17.0%	83.0%	93.9%	6.1%
OVEC	NA	NA	80.5%	19.5%
MEC	41.1%	58.9%	89.5%	10.5%
PE	18.7%	81.3%	96.2%	3.8%
PECO	13.5%	86.5%	86.7%	13.3%
PEPCO	31.6%	68.4%	99.7%	0.3%
PPL	0.1%	99.9%	87.2%	12.8%
PSEG	33.2%	66.8%	98.9%	1.1%
REC	100.0%	0.0%	77.7%	22.3%
Total	17.3%	82.7%	90.2%	9.8%

Credit

There were three collateral defaults and one payment default in the first six months of 2023.

On December 21, 2021, PJM submitted a change to the credit rules to FERC.[44] Under the proposed rules PJM would replace the current credit calculation, which is largely based on a weighted average historical FTR value, with an initial margin based on a risk confidence interval from an historical simulation (HSIM) analysis model. PJM's proposal included the use of a 97 percent confidence interval, meaning a 97 percent probability that the initial margin collected would cover potential default costs. The MMU recommends the use of a 99 percent confidence interval when calculating the initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions.

The most fundamental point is that if costs are shifted from FTR buyers to other market participants, no cost-benefit analysis can show that the other market participants benefit in any way. Under the current default rules, the cost of default is socialized to all market participants, not just those participating in the FTR market. The 99 percent confidence interval places more of the risk where it belongs, on the FTR market participant that is engaged in the risky behavior, than the 97 percent confidence interval. The goal of internalizing as much of the risk to the FTR participants as possible, where it belongs, could be more directly addressed either by using 100 percent or by ensuring that the tail risk be borne solely by those in the FTR market rather than all market participants.

On February 28, 2022, FERC rejected PJM's filing recommending a 97 percent confidence interval because the record did not support 97 percent.[45] FERC instituted a Section 206 proceeding, but recognized that PJM could propose revisions through a Section 205 filing. On June 3, 2022, PJM submitted the same change to the credit rules as the December 21, 2021 filing to FERC.[46] The June 3, 2022, filing included a cost benefit analysis for the proposed use of a 97 percent confidence interval compared to the use of a 99 percent confidence interval. The MMU continues to recommend the use of a 99 percent confidence interval when calculating the initial margin requirements for FTR market participants.

On August 2, 2022, FERC accepted and suspended PJM's June 3 filing for a nominal period to become effective August 3, 2022, subject to refund and subject to the outcome of newly established paper hearing procedures.

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and continues to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends a method under which defaulted FTRs would be canceled rather than holding or liquidating them. Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. But cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

44 *See* "Revisions to PJM's FTR Credit Requirement and Request for 28-Day Comment Period," Docket No. ER22-000 (December 21, 2021).
45 See 178 FERC ¶ 61,146.
46 *See* "Revisions to PJM's FTR Credit Requirement," Docket No. ER22-000 (June 2, 2022).

FTR Forfeitures

By order issued January 19, 2017, the Commission determined that the FTR forfeiture rule is just and reasonable and "...serves to deter such manipulation" related to virtual transaction cross product manipulation.[47] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: deter manipulation, provide transparency allowing participants to modify their behavior, base forfeitures on an individual participant's actions and is not punitive.[48]

The point of the FTR forfeiture rule is to avoid an inefficient and costly market power mitigation process and to establish an objective rule that prevents manipulation of the FTR market. The FTR forfeiture rule is designed to remove the incentive to engage in manipulation. The rule does not result in findings of manipulation.[49]

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[50] If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the constraint line limit, and that constraint affects an individual FTR's target allocation by $0.01 or more, the participant's net virtual portfolio increased the value of the FTR, and the FTR is subject to FTR forfeiture. The FTR forfeiture also requires that congestion on the FTR path in the day ahead market be greater than congestion on that path in the real time market.

The FTR forfeiture rule does not require FTR holders to pay penalties. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR forfeiture rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule is less effective than initially intended as a result of the element of the rule requiring that day-ahead congestion on the FTR path be greater than real-time congestion the same path. As a result of model differences, there is a significant opportunity for virtual participants to profit from differences between day-ahead and real-time prices without driving the prices together, termed false arbitrage. As a result, FTR holders can use virtual positions to make their FTR positions more valuable without violating the rule.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

On June 24, 2019, PJM implemented a new method to calculate the hourly cost of an FTR only for hours in which it is effective.[51] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the 2020/2021 planning period, total FTR forfeitures were $4.6 million.

On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule.[52] In this order, FERC required PJM to modify the FTR forfeiture rule and submit a compliance filing. As a result, there was no FTR forfeiture rule in place from May 21, 2021 until February 1, 2022. These months have zero forfeiture in Figure 13-19.

On June 21, 2021, PJM filed a request for clarification, or alternatively rehearing.[53] PJM asked that FERC clarify the status of the forfeitures that were

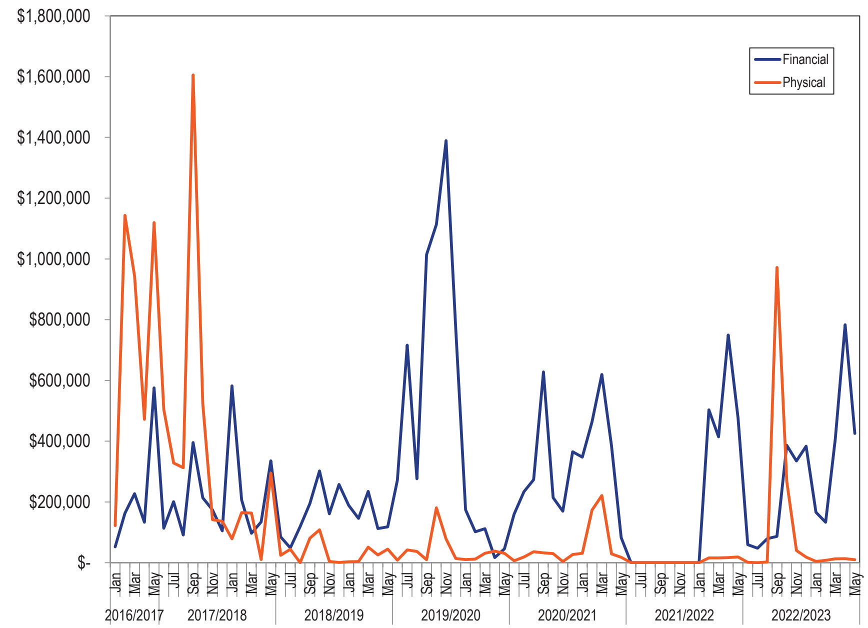
47 See 158 FERC ¶ 61,038 at P 33 (2017).
48 See *id.* at P 62.
49 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).
50 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 State of the Market Report for PJM*, Volume II, Section 13: Financial Transmission Rights for the full history.
51 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).
52 See 175 FERC ¶ 61,137 (2021).
53 See Request for Clarification or, in the Alternative, Rehearing of PJM Interconnection, LLC, FERC Docket No. ER17-1433-000 (June 21, 2021).

assessed over the four years between the initial FERC order for a compliance filing, and their order rejecting PJM's compliance filing. On July 19, 2021, PJM made a compliance filing to address FERC's concerns with the $0.01 element of the FTR forfeiture rule.[54] PJM's compliance filing eliminated that element and replaced it with a constraint based FTR forfeiture. The forfeiture is based on the increased value of each constraint that violates the rule, determined by the shadow price multiplied by the net dfax on that constraint. This change meets FERC's previously established criteria established under the initial FERC order and creates a more precise FTR forfeiture value, to meet the criteria established under the new FERC order.

On January 31, 2022, FERC accepted PJM's July 19, 2021 compliance filing to implement FTR forfeitures using a constraint based method, effective February 1, 2022.[55]

Figure 13-19 shows the monthly FTR forfeitures under the FTR forfeiture rules in effect from January 19, 2017, through May 31, 2023. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures decreased significantly, and stabilized, as participants received information on their FTR forfeitures. Calculations of forfeitures under the new constraint specific rule from February 1, 2022, through May 31, 2023, are included in Figure 13-19.

Figure 13-19 Monthly FTR forfeitures for physical and financial participants: January 2017 through May 2023



54 *See* "FTR Forfeiture Rule Compliance Filing," FERC Docket No. ER17-1433 (July 19, 2021).
55 See 178 FERC ¶ 61,079.