Financial Transmission Rights Market Review

PJM FTR Group

April 2020

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Contents

I. Executive Summary

The paper presents analysis and explanation demonstrating that the current FTR product is fulfilling its intended purpose, and that the long-term FTR product and participation by financial traders add value to the market.

The existing ARR/FTR construct is working well. It has functioned as a key component of the Locational Marginal Pricing (LMP) market design for over 20 years, and it has been continuously refined to serve as a sophisticated and efficient method to provide the value of the transmission system back to those who pay its embedded cost. The original intent of the FTR product has been well established to serve as the financial equivalent of firm transmission service, and to ensure open access to firm transmission service by providing a congestion-hedging function. The existing construct has been successful in promoting load serving entity (LSE) and firm point-to-point customer participation, alongside financial participants, to efficiently value the transmission system and secure hedging mechanisms against congestion costs for up to three years in the future, while also providing a guarantee of a minimum hedge to firm transmission customers for ten years into the future.

Financial participants, or non-load serving or point-to-point entities, contribute value to the existing ARR/FTR construct by applying competitive forces that provide a more accurate valuation of available transmission capability. This added competition also creates enhanced liquidity, so all market participants can more easily purchase, reconfigure or sell back transmission rights. Throughout this paper, these concepts are supported through empirical analysis of historical FTR auction data.

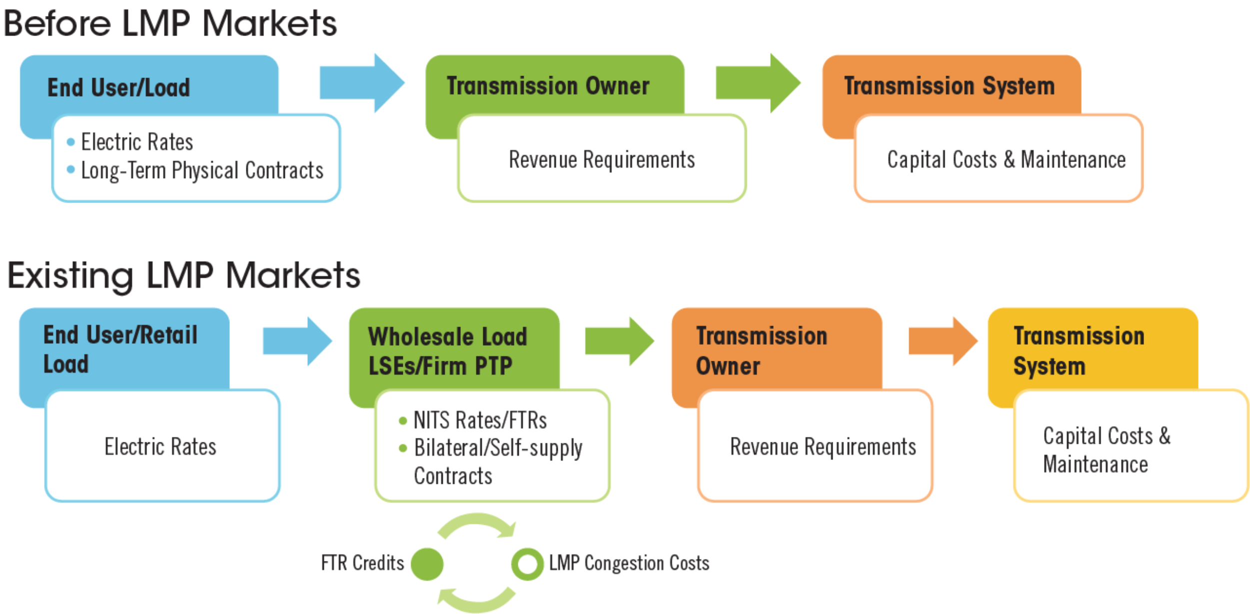
Although the existing ARR/FTR-path-based point-to-point construct is working well, it should not be accepted as a perfect or singular mechanism. The Independent Market Monitor (IMM) has stated a concern that a potential misalignment exists between the allocations of congestion rights (ARRs) and congestion charges paid by load. PJM staff agrees that this concern, as well as any others, should be explored. However, potential market reforms should be considered with the understanding that the existing point-to-point construct is fundamental to the original design of the FTR product and its interaction with the energy market, as is demonstrated in this paper.

A new task force has been created by the Markets Implementation Committee. The ARR/FTR Market Task Force (AFMTF) is authorized to explore areas for improvement in a holistic fashion, including, but not limited to, the alignment of transmission rights to actual congestion charges and the value of the current set of FTR biddable points. This paper concludes with a proposed path forward designed to foster stakeholder consensus around potential market reforms to be discussed throughout 2020.

II. Background

Before the existence of the LMP market, congestion charges were not transparent. Long-term physical energy contracts were made between the generators and the load, or the LSEs, actually owned the generation resources and transmission facilities, to ensure demand obligations were fulfilled. In the LMP market, self-supply and bilateral transactions (which are predominantly used to serve load) are exposed to congestion, and the FTRs are used to reduce or eliminate this exposure. Figure 1 shows the high-level flow of dollars before the LMP market, and with the existing PJM LMP/FTR market, from the end user through to the investment in the transmission system.

Figure 1. **Cash Flow Before and With the Existing PJM LMP Market**



Under the LMP market instituted by PJM in 1998, congestion occurs on the transmission system when re-dispatch is necessary, resulting in congestion charges to those using the transmission system. The benefits of the LMP market design are well understood as providing transparent price signals that reveal the lowest-cost solution to serve load at each location on the transmission system. However, PJM recognized that the entities that pay for the embedded costs of the transmission system (primarily load) should retain the value of that investment, and thus PJM established the FTR product, which entitles LSEs a credit to offset congestion charges. In essence, FTRs provide a priority right to the transmission system and congestion revenues.

Point-to-Point Nature of FTRs

The point-to-point nature of transmission rights was – at the beginning with FTRs, and remains today with ARRs and FTRs – a core component of the LMP market design. One of the underlying principles for an LMP-based market architecture is that forward contracting (including self-supply and bilateral transactions) should form the bulk of trades settled in the LMP market, so that spot trading (including the Day-Ahead and Real-Time Markets) can provide a viable, competitive option for market participants to cover their residual needs. The reason why forward contracting, self-supply and bilateral transactions are important is because they are the most effective mechanisms for market participants to manage their risk over the long term. The short-term, hourly spot market is volatile by its very nature, and therefore riskier to rely upon as the primary source for sales and purchases by market participants. Because forward contracting, self-supply and bilateral transactions rely on – and must specify – the location at which the transaction occurs or the supply resource, the property right represented by the point-to-point definition of congestion rights (i.e., ARRs and FTRs) allows market participants to hedge their exposure to locational price differences between the location of their forward contract, self-supply or bilaterally contracted supply, and the location of their load obligations. Decoupling the allocation of congestion costs by eliminating the point-to-point nature of the congestion-hedging rights in an LMP market cannot be done without considering the impacts of market participants' ability to manage the risk associated with delivering their physical supply resources to their physical load obligations.

ARRs and FTRs are currently defined through the identification of a source, a sink and a megawatt quantity. As a result, they can be referred to as a "point-to-point right," because they are defined by their source and sink points on the transmission system. They are, however, evaluated, valued and priced according to the flow-based impact they have on the networked transmission system between their source and sink points in the exact same manner as LMPs are calculated. The FTR does not maintain a "contract path," point-to-point transmission service that is relied upon outside of LMP markets, and that does not incorporate the flow-based impacts of transmission service reservations on the transmission system. Contract paths were utilized prior to LMP markets, and in non-market areas, as a mechanism to account for average flows between two locations, but they do not provide a good representation of the actual physical flows.

Table 1, as derived from the IMM State of the Market (SOM) reports, shows the breakdown of how load is supplied in the PJM Day-Ahead Market. The table shows that each year, the load obligation is consistently met, predominantly through self-supply and bilateral contracts. The importance of the point-to-point congestion right ARR or FTR product is apparent as load customers continue to appropriately utilize self-supply and bilateral contracts. Until the load entities shift predominately toward the spot market, the point-to-point ARR or FTR product remains important. The IMM claims that there are issues with the point-to-point construct, because it results in congestion not being returned to load and creates cross subsides. However, the SOM data demonstrates that point-to-point rights (i.e., bilateral and self-supply) are what load mainly uses to serve its load, and the existing FTR product aligns perfectly with these rights. There appears to be no cross subsides, because the congestion returned to load that uses the point-to-point rights are also receiving FTRs on these paths, which creates a perfect hedge.

Table 1. **Method for Supplying Load**

	Spot Market	Self-Supply and Bilateral
2018	27.7%	72.3%
2017	26.7%	73.3%
2016	23.9%	76.1%
2015	29.3%	70.7%
2014	26.7%	73.3%
2013	25.0%	75.0%
2012	23.2%	76.8%
2011	26.6%	73.4%
2010	20.2%	79.8%
2009	17.0%	83.0%
2008	20.2%	79.8%
Average	**24.2%**	**75.8%**

In summary, an efficient LMP spot market is necessary to provide a locational price reference to support forward contracting, self-supply and bilateral arrangements. However, these mechanisms that occur in a time frame before the LMP spot market are important to market participants' ability to manage their risk, and therefore control their costs within a competitive environment. The point-to-point definition that incorporates the network transmission impact of congestion rights is a component to facilitating these mechanisms. Transitioning to a network-based allocation requires considering the impacts on how load is actually served and the fundamental concepts of the original FTR and energy market designs.

Example 1: Incentive to Follow Dispatch With Point-to-Point FTR

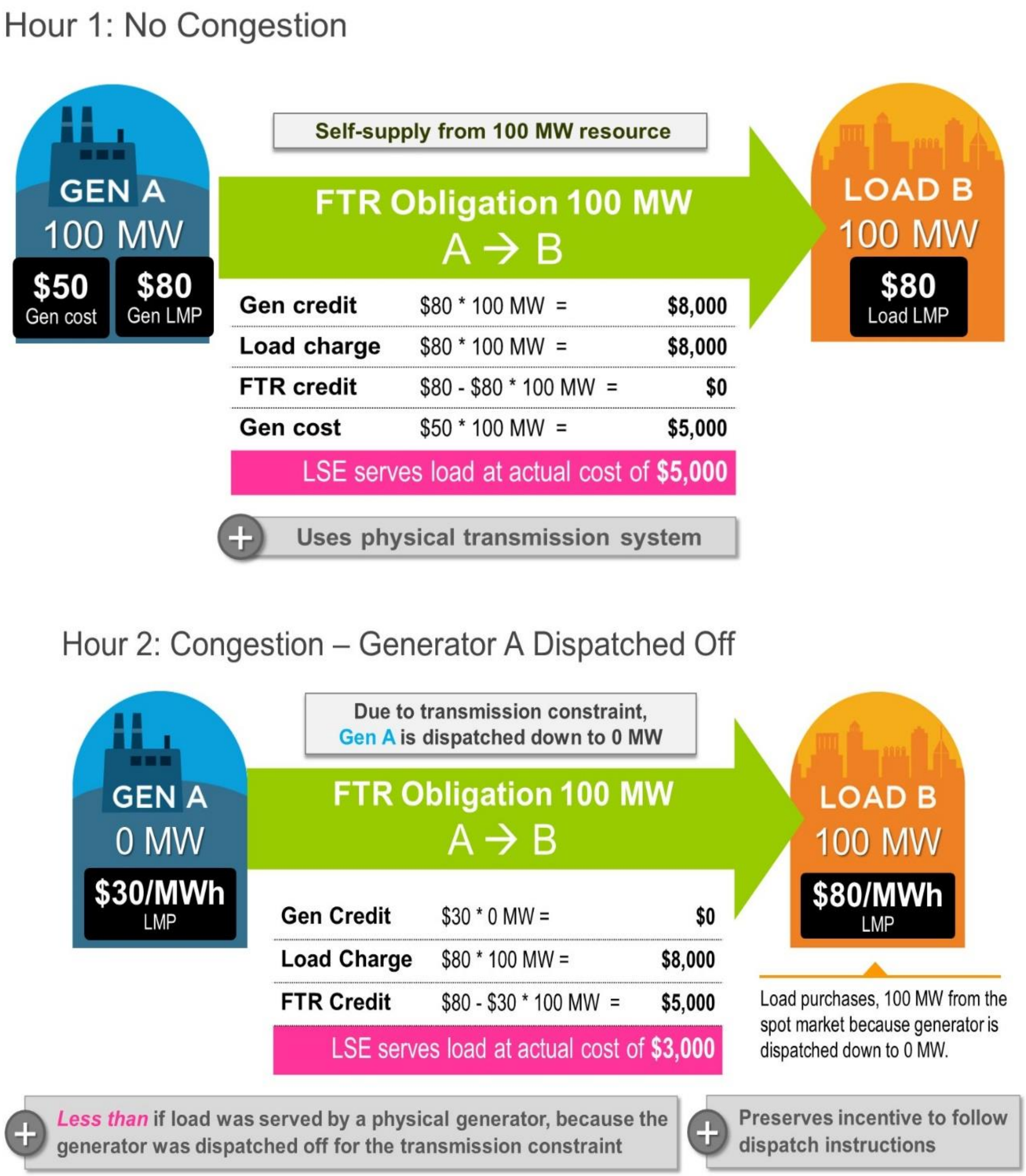
The point-to-point nature of FTRs also supports incentives to follow dispatch for those market participants who self-supply their own load, as demonstrated in the following example. This example demonstrates the potential impact on costs for a load customer who typically self-supplies its obligation. This shows a scenario when the customer follows dispatch instructions and when the customer does not follow dispatch instructions.

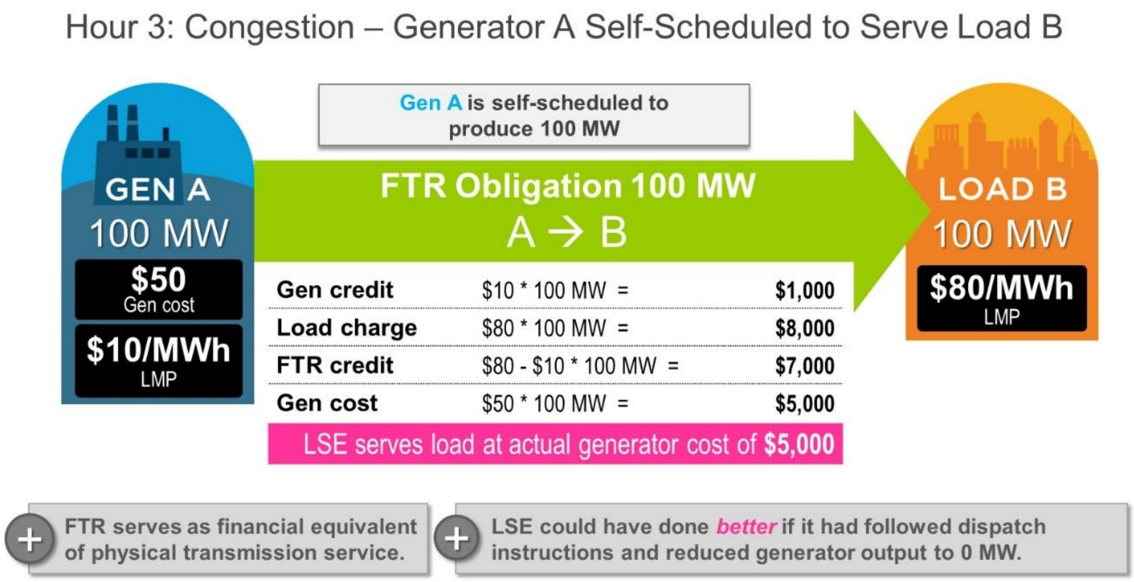
In hour one, when there is no congestion on the system, the cost-to-serve load is simply $5,000, which is the cost of producing power from its owned generator. The self-supplied load obligation means that the customer pays the marginal LMP to serve its load, and correspondingly gets paid the marginal LMP for producing power. The net impact is that the customer is indifferent to the system LMPs and was able to serve its load obligation at costs similar to the pre-LMP market design.

In hour two, the customer is instructed to turn the generator off, because there is congestion on the system. The generator appropriately follows its dispatch instruction, which results in zero revenues from the generator and a charge to serve its load of $8,000 from the spot market. The FTR point-to-point product that aligns with the customer's self-supply contract provides a revenue stream equal to the LMP difference between the source (generator) and the sink (load) locations of the FTR and corresponding self-supply path. The result is a rebate of $5,000 that offsets the LMP spot market costs to serve load of $8,000 for a net cost of $3,000. This cost of $3,000 is actually less than the cost if the customer actually produced the power. The customer had an incentive to follow the dispatch instruction, because the FTR ensured they would still receive the necessary revenues.

In hour three, the customer does not follow the instructions to turn the generator off, which results in a different set of revenue streams. The customer continues to pay the $8,000 load obligation and also receives a generator revenue of $1,000 – well below its actual cost of producing power of $5,000. The FTR rebate is equal to $7,000, which results in a net cost to serve load of $5,000. Although the customer was able to recover its costs, the customer could have done better if it followed its dispatch instructions similar to hour two.

Figure 2. **Example of How FTRs Provide Incentive to Follow PJM Dispatch**





The Addition of ARRs

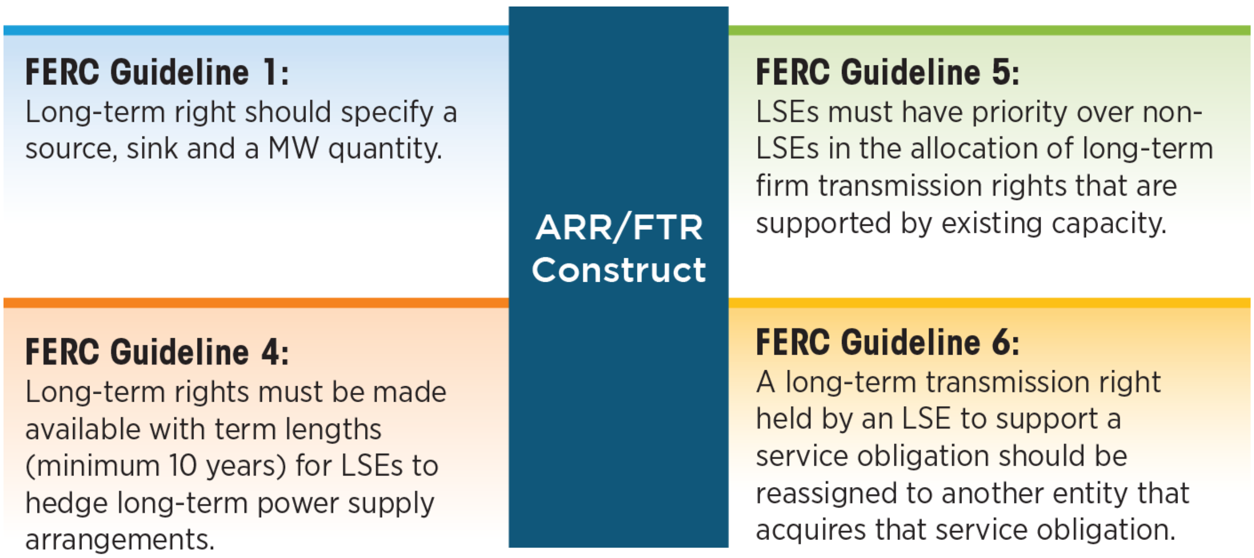
In 2003, PJM added an ARR component to the FTR construct to provide additional flexibility while preserving the priority rights of FTRs to provide congestion revenues to load. The ARR market design accomplishes the following:

- Provides LSEs priority rights to the transmission system and the congestion revenues
- Protects native load utilization of the transmission system while providing long-term certainty
- Provides flexibility to adjust hedging paths annually
- Provides LSEs the choice to collect a fixed revenue stream by holding on to the ARRs, or a refund of congestion revenues on either historical paths, or a different path by converting the ARRs to FTRs through self-scheduling
- Supports retail programs by allowing for reassignment of rights as load switches between LSEs during a planning year

The current ARR/FTR construct provides additional advantages that did not exist in the former FTR-only construct. For example, the current PJM ARR construct provides both the opportunity to hedge based on historical physical contracts, as well as an option to hedge updated physical contracts or expected congestion. This is because of the option of converting the ARRs into FTRs, keeping the ARR credits only, or reconfiguring the ARRs to different FTR paths. This choice is important to load, because it provides load the flexibility to either collect the congestion revenues as it existed prior to the ARR construct, or to collect auction revenues, which are valued solely on the expected value of congestion as determined by the FTR bidders. These options provided to LSEs under the current ARR/FTR construct are not available if congestion revenues are broadly allocated, or if the ARR product did not exist. In addition, the ARR construct preserves the historical rights to load while providing flexibility to acquire the right to congestion revenues on alternative paths. The first rights to the congestion revenues on the historical transmission system are an important component for load in the PJM market, because these rights may correspond to physical transmission rights that predominantly existed before the creation of the LMP market. However, even with the ARR construct and the correlation to historical transmission paths, the load entities can reconfigure these historical paths by applying the auction revenues created by these historical paths to purchase alternate FTR paths in the annual FTR auction.

The PJM ARR/FTR construct also provides a mechanism to meet FERC's guidelines for Long-Term Firm Transmission Rights in Organized Electricity Markets, which stemmed directly from Congress' Energy Policy Act of 2005. Several of these guidelines are directly related to how the PJM ARR/FTR construct is designed. Figure 3 shows the FERC guidelines which directly impacted the design of the current ARR/FTR construct.

Figure 3. **FERC Long-Term FTR Guidelines and PJM ARR/FTR Construct**

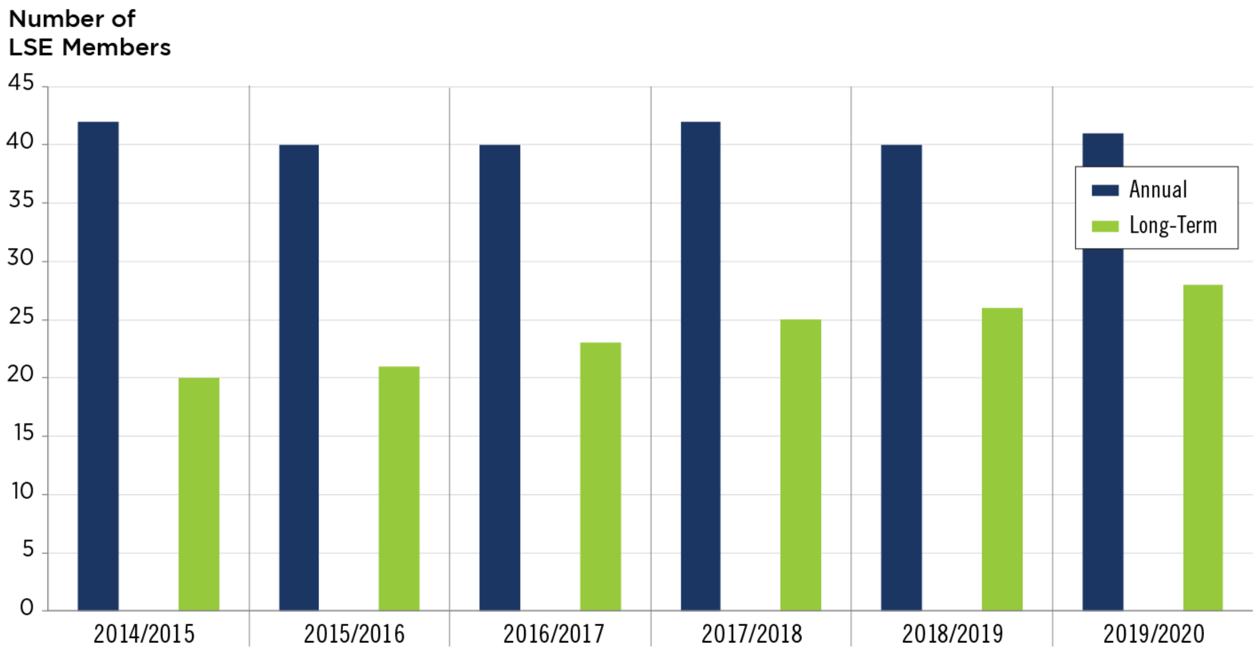


The Addition of Long-Term FTRs

In 2008, PJM and its stakeholders added a 3-year-forward FTR product. The long-term FTR was designed to provide alternatives for physical market participants to hedge forward positions, to provide alignment with state retail load auctions, and to increase financial participant opportunities in the FTR market by increasing the number of tradeable products. It is important to note that in PJM, the pre-existing Stage 1 ARR process met the long-term transmission right requirement guidelines described above in Figure 3 and is outlined by FERC in Order 681. The long-term FTR product was not designed to ensure long-term firm transmission right access. However, priority rights to congestion revenues of LSEs are upheld in the long-term FTR auction by making only the residual system capability for sale after all previously awarded ARRs are assumed to be effective in the model.

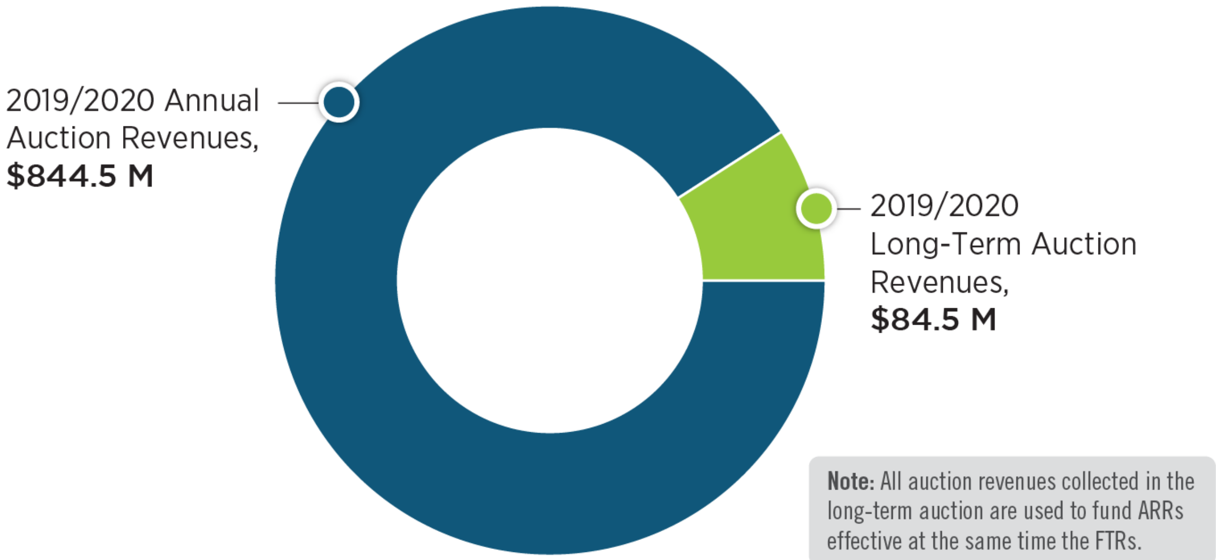
Participation in the long-term market has consistently grown, as is demonstrated in Figure 4, which highlights the participant make-up of the long-term auction. Physical LSEs account for roughly 30 percent of the market participants in the long-term construct, and over half of the active LSEs from the annual auction participate in the long-term auction.

Figure 4. **Load Serving Entity Participation in Long-Term and Annual FTR Auctions**



It is important to note that the available capability for sale in the long-term auction is only the residual capability after all ARRs are presumed to be awarded. The FTR construct thereby preserves first priority of transmission rights to load. Although residual, this capability is valuable to FTR market participants and ultimately consumers. The price signals generated from these auctions are valuable for all market participants, because they provide references to the value of congestion hedges up to three years into the future. This information can be used by competitive LSEs in order to lock in future unknown costs associated with congestion along physical delivery paths, and can therefore lower future contract prices for selling electricity. Figure 5 highlights that for the 2019/2020 effective Planning Period, roughly 10 percent of the auction revenues collected originate from the long-term auction. The vast majority of FTRs are purchased in the annual auction.

Figure 5. **Comparison of 2019/2020 Long-Term and Annual Auction Revenues**



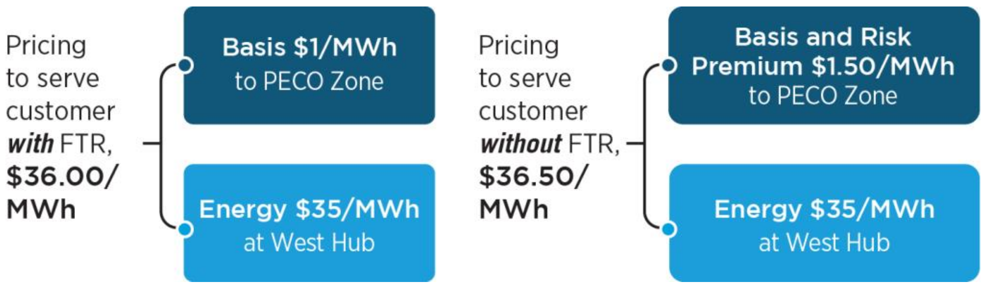
All auction revenues collected in the long-term auction are used to fund ARRs effective at the same time the FTRs are effective. Any surplus after FTRs are 100 percent funded are carried forward month to month. If excess auction funds exist at the end of the planning period, those funds are returned to ARR holders.

In deregulated states within PJM's footprint, Electric Distribution Companies (EDCs) procure electricity supply to customers who are not served by a third-party supplier or competitive retailer through a competitively bid auction process. This service is sometimes known as Basic Generation Service (BGS), Standard Offer Service (SOS), Default Service, or Provider of Last Resort Service. Winning bidders of these auctions are bound to multi-year, retail load obligations (three years is common), and are therefore exposed to PJM wholesale costs including capacity, energy, ancillary services and transmission. Long-term FTRs were designed, in part, to support competitive bids into these state-run auctions by making longer-term hedge contracts available to align with this forward time horizon.

Example 2: Business Model Incorporating Long-Term FTR Auction Prices

Figure 6 describes an actual business model that incorporates forward nodal prices from the long-term auctions. Essentially, long-term FTR clearing prices can provide a level of certainty to unknown future costs associated with wholesale electric supply and can foster more competitive bids into retail load auctions. This can ultimately lower the cost of electricity for certain end-use customers. In the model shown, a generic, wholesale load-pricing deal for 1,000 MW is considered in the PECO zone, and the expected energy cost is $35/MWh. The opportunity in the long-term auction allows for hedging of the expected costs with a lower risk premium ($1/MWh) than what would be needed if it was not acquired until the annual or monthly auction. If you assume the risk premium would be higher in the annual or monthly auction, for example, $1.5/MWh; then purchasing the FTR in the long-term auction would save customers $0.50/MWh or an equivalent of $4.4 million over an annual period ($.5 /MWh * 8,760 h*1,000 MW). These are significant savings that can be attributed to the existence of the long-term auction.

Figure 6. **Commercial Usages of Long-Term FTRs**

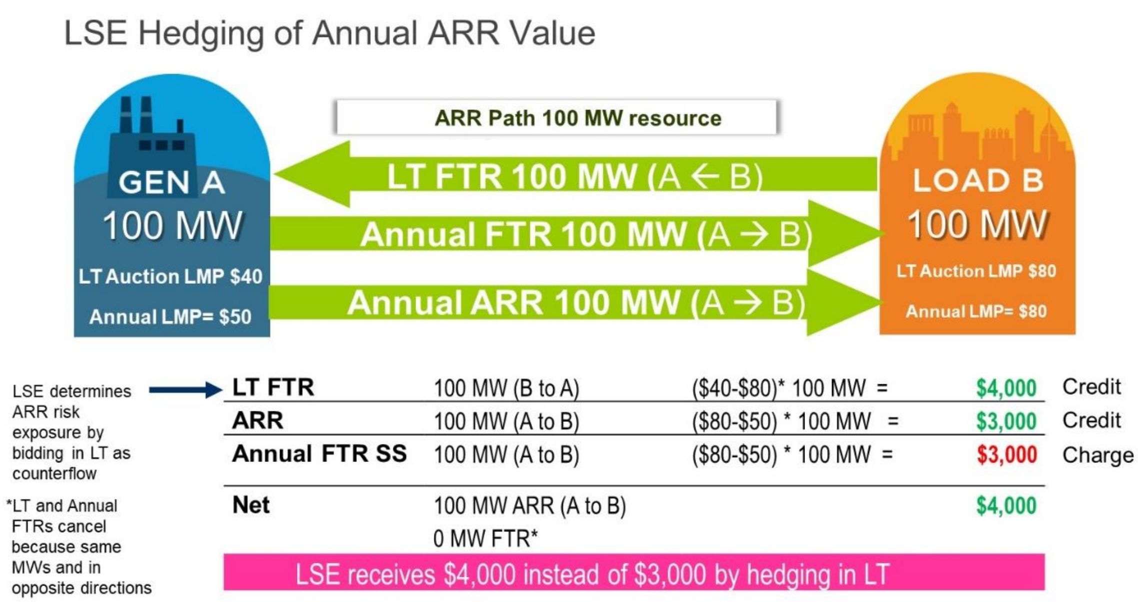


The long-term construct also provides alternatives for physical market participants to hedge forward positions. One of these alternatives allows for LSEs to obtain a supplemental hedge to expected ARR value. An example of this is demonstrated in Example 3.

Example 3: Hedging of ARR Value in Long-Term FTR Auction

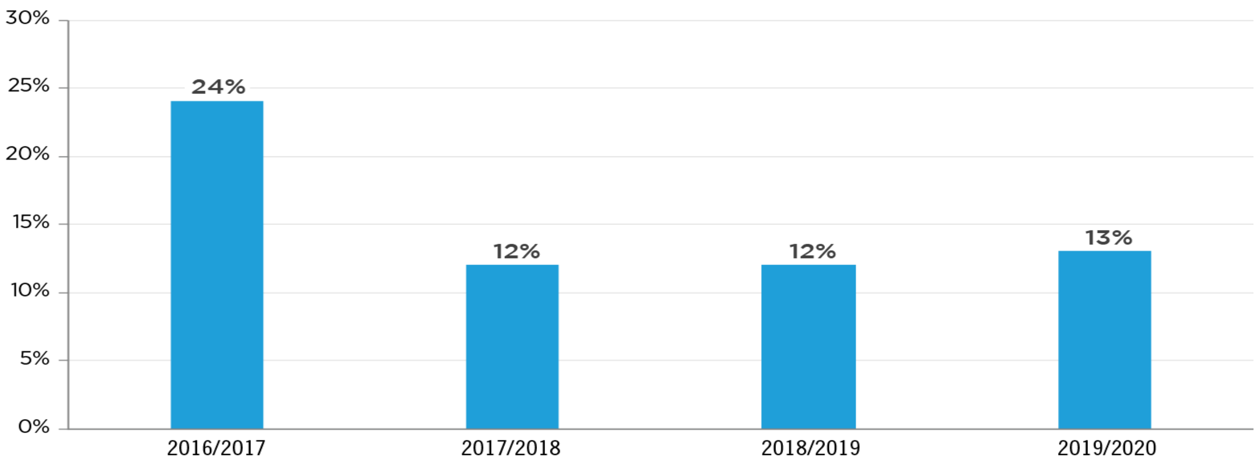
In this example, an LSE purchases an FTR in the long-term auction, counter flow to what their future ARR position will be in the upcoming annual allocation. This long-term purchase results in a future auction credit of $4,000 to the participant. In the subsequent annual auction, the same LSE self-schedules their ARRs into FTRs, which results in a net-zero auction charge ($-3,000 FTR auction charge + $3,000 ARR credit). However, since the counter-flow position was purchased in the long-term auction for the same amount of megawatts and for the same effective period, the resulting day-ahead positions of -100 MW from the long term and 100 MW from the annual auction, net to 0 MW. The LSE is left with what it was willing to accept from the long-term auction – a credit of $4,000. This strategy results in a higher value to load, as opposed to retaining the ARR credits and not self-scheduling – a credit of only $3,000.

Figure 7. **LSE Hedging of Annual ARR Value**



In addition to providing valuable information for LSE participants in state-run auctions, long-term FTR auctions provide more options for non-LSE participation in the market. This participation enhances liquidity and price discovery in the FTR markets by providing more opportunities for buying and selling FTRs. Figure 8 illustrates the level to which long-term FTRs are purchased by financial participants and sold back in the annual auctions. These bids create additional capability for sale in the annual auctions that can range from 40,000 MW to 60,000 MW, based on the percentages of cleared buy-bid megawatts from the long-term auctions.

Figure 8. **Levels of FTRs Purchased in the Long-Term Auctions, Sold Back in Annual Auctions**



Forward price information can also facilitate agreements associated with investment in future generation. Since FTR clearing prices are made public, investors who wish to hedge future costs associated with congestion (e.g., periods of time with lower LMPs or reduced output due to an upstream transmission constraint) can access transparent, three-year-forward nodal pricing created by the long-term markets. These clearing prices inform potential contracts between generation developers and other financial participants more adept at trading FTRs, and avoid the need for developers or investors to seek over-the-counter, opaque offers for hedging contracts.

In response to concerns raised by the IMM in 2018, the original intended benefits of a long-term auction were reevaluated by PJM and its stakeholders through a seven-month stakeholder process. As a result, PJM stakeholders and the IMM agreed that FTR modeling enhancements were needed to better determine available capability of the transmission system up to three years into the future, more efficiently preserve priority rights of future congestion revenues to load, and eliminate the overlapping three-year FTR product due to low liquidity and usage. Those changes were implemented in September 2018.

PJM believes these modeling enhancements represented a step in the right direction toward making the long-term market as efficient as possible. Additionally, PJM and its stakeholders are pursuing opportunities to mitigate financial risk in the FTR market through adjustments to the market design. Those opportunities for improvement include enhanced tracking of price volatility and locational liquidity over time, and improving infrequent pricing signals associated with portfolios beyond one-year forward. These are items PJM intends to address in 2020 at the ongoing Financial Risk Mitigation Senior Task Force (FRMSTF). In addition to risk mitigation, PJM believes there will be benefits to the overall FTR market efficiency as a result of these implementations.

Importantly, the long-term market provides opportunities for LSEs to receive a minimum level of return on their ARRs, which represent increased value to end-use customers, provided there is adequate competition and liquidity in the long-term market. Finally, this opportunity for the LSEs is not possible unless the long-term market has the adequate competition provided by financial participants.

III. FTR Intended Purpose

The current ARR/FTR market construct provides a mechanism for PJM to meet FERC long-term transmission access guidelines. It provides flexibility to LSEs with different risk profiles, and the market enables competition from financial participants. There are several metrics that can indicate how well FTRs are functioning as a hedge to future congestion price risk. Some of those metrics include revenue adequacy, the amount of ARRs allocated, and how well those ARRs are aligned with congestion payments. Revenue adequacy is a direct indication of how well the FTR market model is aligned with the Day-Ahead Market model. The closer these are aligned, the more adequate the revenue adequacy, and the higher the confidence in the marketplace that bids of expected future congestion will come to fruition under normal conditions. The amount and location of allocated ARRs are another indicator as to whether LSEs are receiving a true offset to congestion exposure in the Day-Ahead Market. Finally, looking at financial participation and the competitive forces provided to promote price discovery and liquidity are also indications of a healthy marketplace.

As stated above, the primary purpose of the FTR product is to provide a hedging mechanism against locational price differences, thereby providing the financial equivalent of firm transmission service. The following section provides empirical evidence that shows the current product is fulfilling this intended purpose.

Hedging Efficiency

Since the removal of balancing congestion[1] from the total rents available to fund FTRs in 2015, ARR megawatt awards have increased, and revenue adequacy has been restored in the PJM market. This bolsters confidence in the market and reduces risk premiums in the FTR market, which can devalue ARRs. Overall, load is benefitting, as shown in Table 2, with the inclusion of the allocation of balancing congestion to real-time load plus exports.

Table 2. **ARR Megawatts Allocated and FTR Revenue Adequacy**

Planning Period	ARRs Allocated (MW)	FTR Revenue Adequacy
2015/2016	76,420	105%
2016/2017	80,620	110%
2017/2018	94,229	137%
2018/2019	97,787	*112%

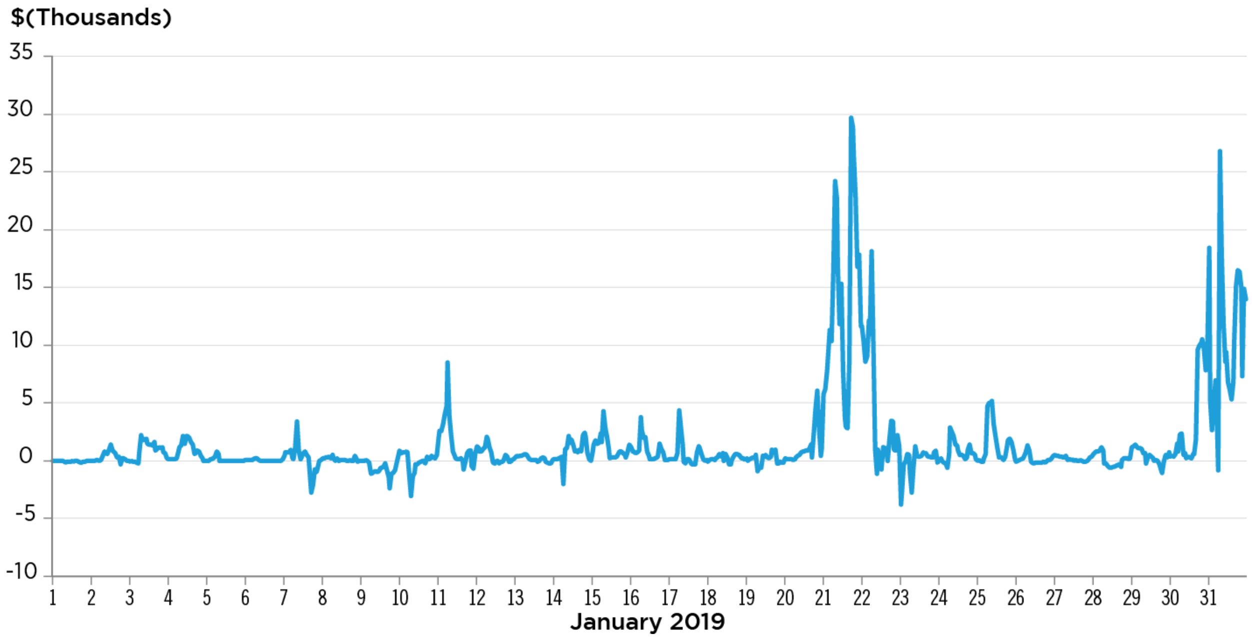
*First planning period where surplus revenues are returned to ARR holders, not FTR holders

As anecdotal evidence to demonstrate whether the FTR market provides valuable hedging mechanisms to actual LSEs via the current point-to-point definition, PJM examined two specific participants' portfolios over similar time

[1] https://www.ferc.gov/CalendarFiles/20160915170050-EL16-6-001.pdf

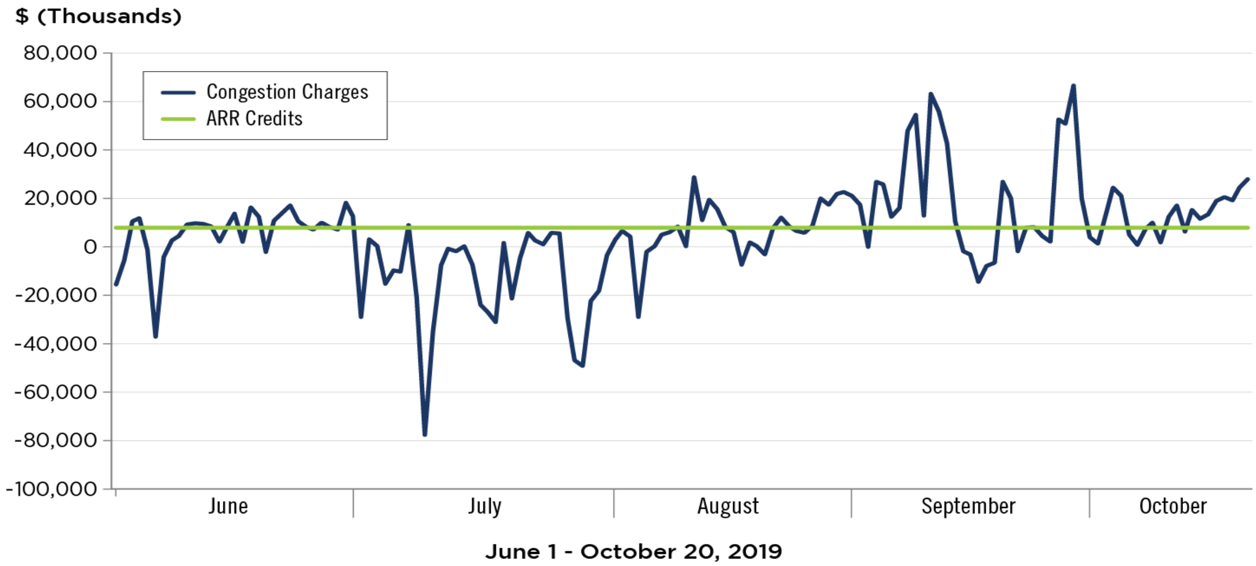
horizons. The first LSE was studied for the 2019/2020 Planning Period to-date, as well as the heavily congested month of January 2019 in order to illustrate hourly detail; the second LSE was studied for the 2019/2020 Planning Period to-date. These participants' day-ahead transaction data, including injections, withdrawals and internal bilateral transactions, was analyzed along with their FTR and ARR portfolios over the same period of time. The first LSE self-schedules its ARRs into FTRs and self-supplies its own load. This LSE, as can be seen in Figure 9, is sufficiently hedged against day-ahead congestion charges for all but four days of the month. Additionally, this LSE is 130 percent hedged so far for the 2019/2020 Planning Period, when comparing hourly, day-ahead congestion charges to hourly self-scheduled FTR credits.

Figure 9. **Example of 2019 Hourly Congestion Exposure for PJM Load Serving Entity Utilizing Self-Scheduled FTRs**



The second LSE, who partially self-supplies its own load, elected to retain their ARR credits and hence auction off their right to FTR revenues. Figure 10 demonstrates that this LSE is hedged at a daily average of 136 percent so far for the 2019/2020 Planning Period, when comparing hourly, day-ahead congestion charges to daily ARR credits. This data demonstrates that the current, path-based product is capable of providing a complete congestion hedge to these LSEs given its specific supply locations, both in the case where the LSE chooses to self-schedule ARRs into FTRs, and also in the case where the LSE elects to keep ARR revenues and not acquire FTRs.

Figure 10. **PJM Load Serving Entity ARR Versus Day-Ahead Congestion Charges for PJM Load Serving Entity That Retains ARR Credits**



Congestion Returned to Load – An Indicator Not Objective

FERC has stated multiple times that the sole purpose of the FTR product is **not** to return 100 percent of congestion to load. An FTR market designed to achieve this goal could reduce the incentive for needed investments in generation resources and transmission upgrades. In January 2017, the Commission stated:

"Finally, the Market Monitor and Joint State Commissions reiterate the proposal, as made in their earlier filings, that the Commission should support a market redesign to ensure loads receive all congestion revenues. ***We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load, and the market should therefore be redesigned to accomplish that directive****. FTRs were designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion-hedging function. The purpose of FTRs to serve as a congestion hedge has been well established. In the Energy Policy Act of 2005, Congress added section 217(b)(4) to the FPA, directing the Commission to exercise its authority to "enable load serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs." In Order No. 681, the Commission clearly emphasized the significance of FTRs in hedging congestion price risk."*[2]

Although not the intended purpose, useful information can be gathered from current percentages of congestion returned to load from the existing construct to determine if enhancements should be pursued. Table 3 shows the FTR credits, and percentage of congestion hedged by load, under the existing FTR funding mechanism, and how that percentage would have changed depending on the choice by LSEs on whether to self-schedule ARRs into FTRs or not. These values, derived from the Monitoring Analytics State of the Market Report, include the cost of balancing

[2] https://www.pjm.com/directory/etariff/FercOrders/2048/20170131-el16-6-002,%20003,er16-121-001.pdf

congestion, which is currently allocated to load. Importantly, under the existing rules for the 2018/2019 Planning Period, where the end-of-planning period surplus is allocated to load, the percentage of actual congestion returned to load ranged from 82 percent to 104 percent, depending on the decision made by load to self-schedule ARRs into FTRs or not. These statistics demonstrate that the actual congestion returned to load can vary based on the decisions and risk profile of the LSEs, and that there is no guarantee for full funding. Additionally, these percentages should not be interpreted as a failure of the FTR market, but rather as an indicator that the choice by the LSE may impact their hedged congestion.

Table 3. **Congestion Returned to Load**

Planning Period	Actual Percent Offset to Load	Percent Offset If 100% Self Scheduled	Percent Offset If 0% Self Scheduled	ARRs Allocated	Notes
2015/2016	78%	66%	88%	76,420	
2016/2017	93%	71%	109%	80,620	
2017/2018*	50%	61%	36%	94,229	Skewed by Polar Vortex
2018/2019	92%	82%	104%	97,787	Surplus allocated to Load improves offset

*Actual percent offset is 69 percent if January 2018 excluded.

Further investigation at a zonal level can reveal if the allocation of rights align with the actual congestion returned to load. This is an important investigation, because although the data shows from a system-wide perspective that congestion returned to load may be appropriate under the existing construct, the actual alignment within zones may be unbalanced. In an attempt to quantify the alignment of rights with actual congestion returned to load both Monitoring Analytics and PJM provided a breakdown for the 2018/2019 planning year on a zonal level. The method to determine the alignment was calculated differently between Monitoring Analytics and PJM. The key difference was the calculation of the congestion for each zone. Monitoring Analytics determined the congestion for each zone from the transmission constraints and impacts to each transmission zone. However, PJM determined the congestion for each zone using the PJM invoices and actual costs incurred by each customer. The Monitoring Analytics data is represented in Table 4. For this planning year, it demonstrates for some zones an unbalanced allocation of rights compared to congestion as it is calculated on a system level. Although the table represents congestion calculated for each zone based on actual transmission constraints, it does not represent the actual payments that were made by customers, reflected on their PJM invoices. Actual costs paid by customers are a reflection of the CLMPs and the allocation of rights compared to actual costs will vary by participant. PJM's data is represented in Table 5 for load customers and the offset values are calculated directly from the actual costs incurred and reflected on the PJM invoices. Although the actual data represented in PJM's Table 5 is still not in a perfect alignment, it demonstrates a better aligned offset then the theoretical values Monitoring Analytics calculated. Additionally, both data sources are only incorporating FTRs associated with LSEs who self-scheduled their ARRs into FTRs. LSEs can and also purchase FTRs in Auctions to improve their hedging.

Table 4. Monitoring Analytics 2018/2019 Zonal Congestion Offset Table

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

Table 5. PJM 2018/2019 Zonal Congestion Offset Table

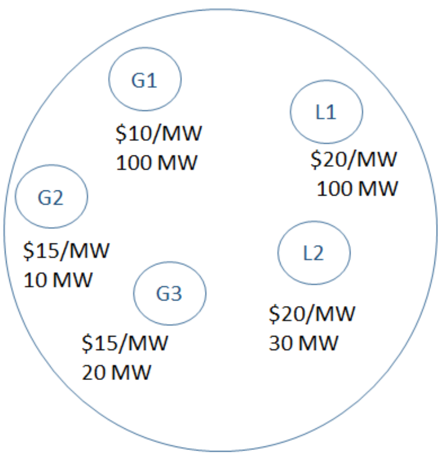
						Settled Costs			
Zone	ARR Credits	FTR Credits	Balancing + M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion (Includes M2M)	Balancing Congestion (Includes M2M)	Total Congestion	Offset
AECO	$4.9	$0.0	-$1.9	$0.8	$3.8	-$19.9	$1.5	-$18.4	100%
AEP	$56.8	$38.9	-$23.7	$21.8	$93.8	$126.3	-$0.2	$126.1	74%
APS	$40.8	$10.4	-$9.2	$8.9	$50.9	$26.6	$0.6	$27.1	188%
ATSI	$43.3	$0.3	-$12.4	$6.7	$37.9	$96.7	$2.4	$99.1	38%
BGE	$67.2	$1.5	-$5.8	$10.7	$73.6	$45.5	$0.9	$46.4	159%
COMED	$91.7	$10.2	-$17.8	$17.3	$101.4	-$13.7	$5.0	-$8.7	100%
DAY	$7.2	$0.5	-$3.2	$1.1	$5.6	$30.8	$0.8	$31.5	18%
DEOK	$41.5	$9.1	-$5.0	$7.7	$53.3	$78.4	$1.6	$80.0	67%
DUQ	$9.1	$0.0	-$2.5	$1.4	$8.0	-$33.3	$1.9	-$31.4	100%
DOM	$7.1	$44.3	-$18.7	$9.4	$42.1	$26.2	$4.0	$30.2	140%
DPL	$39.3	$8.2	-$3.4	$7.0	$51.1	$50.0	$0.4	$50.4	101%
JCPL	$2.5	$0.0	-$4.2	$0.4	-$1.3	$82.8	-$3.8	$79.0	-2%
METED	$7.9	$0.4	-$2.9	$1.3	$6.7	-$6.5	$0.0	-$6.5	100%
PECO	$21.2	$0.2	-$7.5	$3.3	$17.2	-$51.5	$0.7	-$50.8	100%
PENELEC	$10.9	$4.0	-$3.2	$2.0	$13.7	-$11.4	$0.7	-$10.7	100%
PEPCO	$28.9	$2.0	-$5.5	$5.0	$30.4	$28.8	-$0.2	$28.6	106%
PPL	$4.4	$0.0	-$7.6	$0.7	-$2.5	-$35.7	-$0.6	-$36.3	100%
PSEG	$40.9	$0.0	-$8.1	$6.3	$39.1	-$22.9	$0.6	-$22.3	100%
RECO	$0.1	$0.0	-$0.3	$0.0	-$0.2	-$2.3	$0.1	-$2.2	100%
Misc.	$3.3	$0.1	-$2.3	$0.5	$1.6	-$12.1	$0.7	-$11.4	100%
Total	$529.0	$130.1	-$145.2	$112.3	$626.2	$382.7	$17.2	$399.9	157%

*Table reflects Load Serving customers only
*Congestion for Load participants that serve across multiple zones is apportioned based on load obligations
*Zones with total negative congestion charges set to 100% offset
*Misc includes zones with less than three LSEs and Merchant customers

The following simple example demonstrates the differences in how Monitoring Analytics and PJM is calculating congestion and the impact on hedging. In this example the congestion can be calculated from a theoretical standpoint or directly from the actual payments made by the customer.

Example 4: How Congestion is Calculated and Settled

Figure 11. **Example of Congestion Calculations:**



*LMPs represent Congestion LMPs
*Assumes single constraint with same impact on L1 and L2

<u>Total System Congestion</u>

Total Congestion= CLMP Load - CLMP Generator

Total Congestion = [($20*100)+($20*30)] – [($10*100)+($15*10)+($15*20)]

Total Congestion=$1,150

<u>Theoretical Network Congestion for each LSE</u>

- Alta (L1): $1150 * 100/(100+30) = $884.6
- Vola (L2): $1150 * 30/(100+30) = $265.4

→ Total= $1,150

<u>Actual Settlements</u>

Participant	Ownership/ Obligation	Congestion Load Payment	Congestion Generator Revenue	Net
Alta	G1, L1	$2,000	$1,000	$1000
Vola	L2	$600	$0	$600
Sundance	G2	$0	$150	-$150
Parkplace	G3	$0	$300	-$300
Total		$2,600	$1,450	$1,150

In Figure 11, the diagram represents a system that consists of three generators labeled G1, G2, and G3. Additionally, there are two loads labeled L1 and L2. It is assumed for simplicity that there is only one constraint on the system that equally impacts L1 and L2. The total system congestion is easily calculated by taking the difference between the LMP prices at the generator and the load locations. This total congestion is equal to $1,150, as demonstrated in Figure 11. The congestion assigned to each LSE can be calculated based on the theoretical or actual payments made in an LMP market. The theoretical congestion is calculated by taking the total congestion and apportioning it to each LSE based on the impacts from the constraint. This can be done because the impact on the constraint is the same on both L1 and L2. Alta, L1, would have $884.6 of congestion and Vola, L2, would have $265.4 of congestion. However, in an LMP market the actual settlement is based on the injections and withdrawals for each customer using the congestion LMPs (CLMPs) and not based on a theoretical value. The actual settlements using injections and withdrawals is demonstrated in the table as part of Figure 11. In this table all participants, both generator and load customers, have a contribution to the congestion costs via the CLMP component. Additionally, Alta self-schedules its energy from the G1 location to the L1 location. This is a common practice, as discussed earlier in this paper. The results of the actual settlement calculations were derived from the CLMPs multiplied by the MWs at the generator injection locations and the load withdrawal locations. The result is that each customer is assigned a cost or a credit with the total value of the congestion equal to $1,150, which is the same total of the system congestion. While the assignment of cost can be calculated using two methods, the actual costs are based on injections and withdrawals in an LMP market and not theoretical congestion. While the theoretical calculation assumes that 100% of load is purchased from the spot market the reality is that only a small percentage is actually purchased from the spot market. In fact, less than 25% of load is purchased from the spot market while most is served via self-supply or bilateral contracts. This is important to understand because a key characteristic of an LMP market is not to support 100% spot market purchases but to recognize how load is served and protect existing mechanism for serving this load. To further demonstrate the impacts we can look at the actual hedging on Example 4.

Figure 12. **FTR Allocation for Example 4**

If Network FTR	If Point-to-Point FTR (Existing construct)
• Alta FTR value: $884.6	• Alta FTR value: $1000
• Alta Actual Costs: $1000	• Alta Actual Costs: $1000
• Net Hedge= 92%	• Net Hedge= 100%
• Vola FTR Value:$265.4	• Vola FTR Value: $150
• Vola Actual Costs: $600	• Vola Actual Costs: $600
• Net Hedge= 44.2%	• Net Hedge= 25%

In Figure 12, the box on the left represents the congestion hedge if FTRs were allocated using a network approach that aligned with the theoretical network congestion. The FTR value is set equal to the theoretical network congestion for LSE Alta and Vola. Comparing these FTR values to the actual costs incurred for these LSEs results in a hedging percentage of 92% for Alta and 44.2% for Vola. These actual costs are based on how these LSEs actually serve their load. Alta, is not hedged fully while Vola is exposed to more risk with spot market purchases only. The box on the right represents the congestion hedge if FTRs were allocated using the existing PJM point-to-point construct. The FTR value is the difference between the CLMPs at the source and sink locations multiplied by the load MW obligations. Alta's FTR aligns exactly with its energy delivery to serve its load and consequently has a 100% hedge of its congestion costs. Vola only has a 25% hedge because of the added risk of spot market purchases only. Importantly, the point-to-point construct of the FTR allocation aligns with existing energy deliveries, a core LMP design feature. The spot market purchase to serve load, which is not typically how energy is served, is at a higher risk. However, this risk creates an incentive for this load entity to invest into the transmission system to remove the unhedged congestion, another important LMP design feature.

However, there is room to improve the alignment of allocated rights with congestion in the current construct. PJM and the IMM have agreed to explore this area further with stakeholders by taking a holistic approach to re-examine the allocation construct. For example, a potential modification to the current allocation construct would be to change the Stage 1 ARR historical source locations to align better with actual energy deliveries and to optimally allocate the full transmission system to those customers who pay for it.

IV. Precedent and Theory of Value Added From Financial Participants

The current FTR product, which preserves the first priority of congestion revenues to load, also promotes a robust, competitive market. The ability for financial participants to compete for excess capability in an auction format provides LSEs an opportunity to either purchase rights at a lower cost or sell the rights they are allocated for more than they believe they would be worth if they retained them as congestion hedges.

Federal Power Act (FPA) Section 217 states that FERC may permit transmission rights not allocated to LSEs to be made available to other entities in a manner the Commission determines to be just and reasonable and not unduly discriminatory or preferential.[3] Further, open-access principles were shaped "to remove impediments to competition in the wholesale bulk-power marketplace and to bring more efficient, lower-cost power to the nation's electricity consumers." The Commission's precedent holds that FTRs "play a key role in ensuring open access to firm transmission service by providing a congestion-hedging function."[4] These precedents provide for purely financial entities to participate alongside LSEs and point-to-point customers in the FTR auctions, provided they are creating competitive forces which ultimately benefit end-use customers.

In a Stanford University research paper by Gordon Leslie[5] entitled, "Why Do Transmission Congestion Contract Auctions Cost Ratepayers Money? Evidence from New York," Leslie states, "financial traders participate in the markets, with the motive to acquire derivatives at prices less than their eventual payout. Competition among traders can cause price signals for derivatives to converge on the expected payouts of the products, and aid physical firms in their long-term energy procurement process."

Although the existence of these competitive forces can be demonstrated at a high level in the PJM market, it is essential that the value of market liquidity and price convergence be quantified to the extent possible. Such analysis must include a determination of whether or not profits garnered by financial traders in the PJM market are in balance with the benefits they provide LSEs. The potential for non-value-added trading, which can simply extract funds from the market to the detriment of end-use customers by way of devalued or inefficient hedges along physical supply paths, is something that should be further examined.

In order to illustrate whether or not financial participants create competitive forces which can enhance market liquidity and contribute to price discovery, a hypothetical study removing the bids from purely financial traders and holding all other bids constant was performed to show the impact on ARR values for the 2018/2019 and 2019/2020 Planning

[3] https://legcounsel.house.gov/Comps/Federal%20Power%20Act.pdf

[4] https://www.pjm.com/-/media/committees-groups/task-forces/frmstf/20190717/20190717-info-only-caiso-reduction-in-biddable-points-june-2018-ferc-order-er18-1344.ashx

[5] https://www.arec.umd.edu/sites/arec.umd.edu/files/_docs/events/Gordon%20Leslie-Why%20do%20transmission%20congestion%20contract%20auctions%20cost%20ratepayers%20money-Evidence%20from%20New%20York.pdf

Periods. Results show a devaluation of roughly $329 million in 2018/2019 and $150 million in 2019/2020 without financial participation.

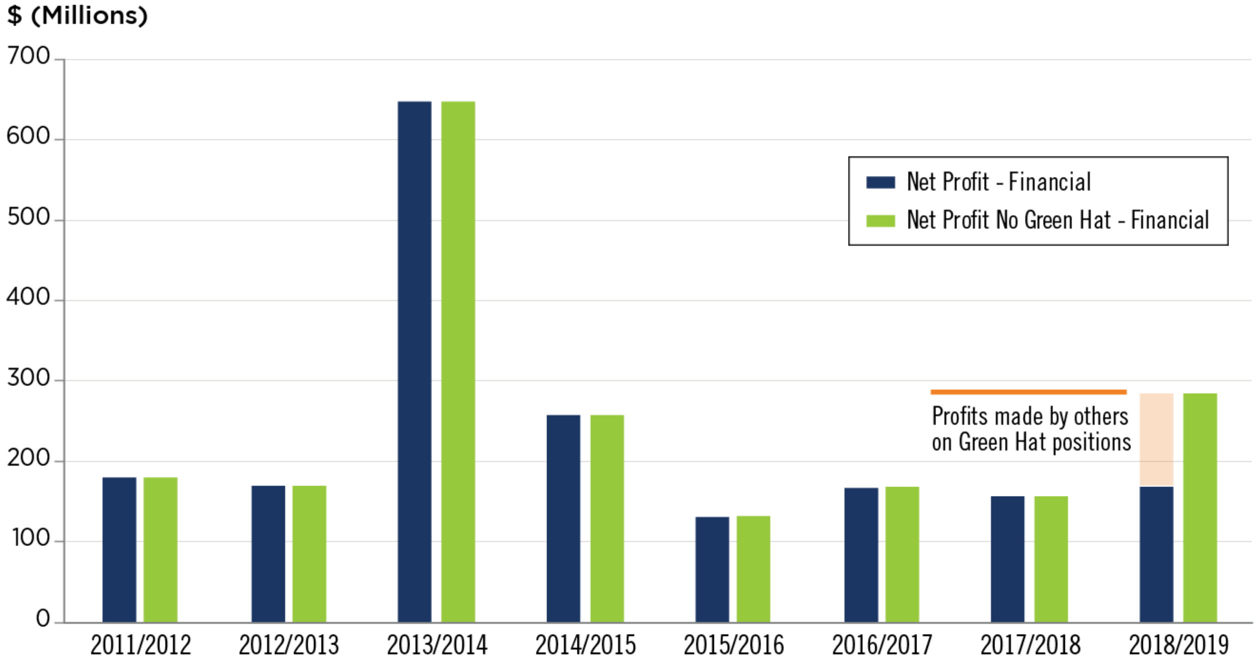
Table 6. **Annual Auction Studies Without Financial Participant Bids**

Planning Period Study	Baseline		No Financial Participants	
	Participants	ARR Value	Participants	ARR Value
2018/2019	189	$784 M	79	$455 M
2019/2020	196	$811 M	71	$656 M

Table 5 clearly illustrates that added competition from financial participants benefits load by increasing the overall value of available transmission capability. Correspondingly, this benefit to load has been accompanied by fairly consistent profits by financial participants for the past eight years. Figure 13 shows that these profits have remained steady since 2011, remaining well below $200 million per year in most years. Financial participant FTR profits peaked in the 2013/2014 Planning Period due to the impact of the January 2014 Polar Vortex. Forward markets cannot accurately project extreme weather conditions, nor are they designed to forecast these events. During these events when congestion prices spike, holders of those FTRs – who have purchased them more cheaply in the auctions – profit. However, profits by financial participants are not necessarily a bad thing. As demonstrated above, financial trader participation in the FTR markets benefits load through increased liquidity and competition that ultimately provides value to the physical participants through increased revenues and additional congestion-hedging opportunities. Financial traders would not participate in the FTR markets and provide this benefit if there was not the opportunity to profit by doing so.

Another item highlighted in Figure 11 is the additional profit created by taking advantage of GreenHat, LLC positions for the 2018/2019 Planning Period before this company went into a PJM default. Sophisticated traders were able to identify GreenHat, LLC prevailing positions, understand that they would be losers based on future transmission enhancements, and take the FTR opposite from the GreenHat, LLC position. The auction would pay out the counter flow and have a small or zero value in Day-Ahead Markets, resulting in close to 100 percent profit. This activity added up to over $100 million in profits for certain financial participants.

Figure 13. **Non-Load Serving Entity FTR Profits Per Planning Period**



The existence of persistent profits by financial participants has led PJM into an investigation of where and how these profits are derived. In particular, profits that are derived from FTRs that provide little-to-no liquidity or corresponding impact on firm transmission customer revenues or hedging opportunities may not be beneficial to the market. In theory, the cost paid for an FTR, which represents the future price of congestion along a path, should converge to its expected settlement value over time. PJM believes that competition may be lacking on certain pockets of the transmission system which may not align with the physical system. This could be attributable to participants trying to profit simply from modeling discrepancies between the FTR and day-ahead auction models, or the availability of illiquid FTR products due to the size of biddable points.

Preliminary analysis indicates that profitable financial entities can create portfolios with or without unique FTR path source/sink combinations, mainly sourcing and sinking at individual generator and/or load nodes. This is somewhat consistent with Leslie's[6] empirical findings in the NYISO Transmission Congestion Contract market where he states, "financial traders purchase a wider range of products than physical firms, and earn most of their profits when they are the first to buy a previously illiquid product. Traders can improve price signals on these products and can effectively receive a transfer from ratepayers for this service." Figure 12 and Figure 13 illustrate supporting data points from the 2018/2019 FTR market.

[6] https://www.arec.umd.edu/sites/arec.umd.edu/files/_docs/events/Gordon%20Leslie-Why%20do%20transmission%20congestion%20contract%20auctions%20cost%20ratepayers%20money-Evidence%20from%20New%20York.pdf

Figure 14. **Correlation Between Number of Unique Paths Held and FTR Profits**

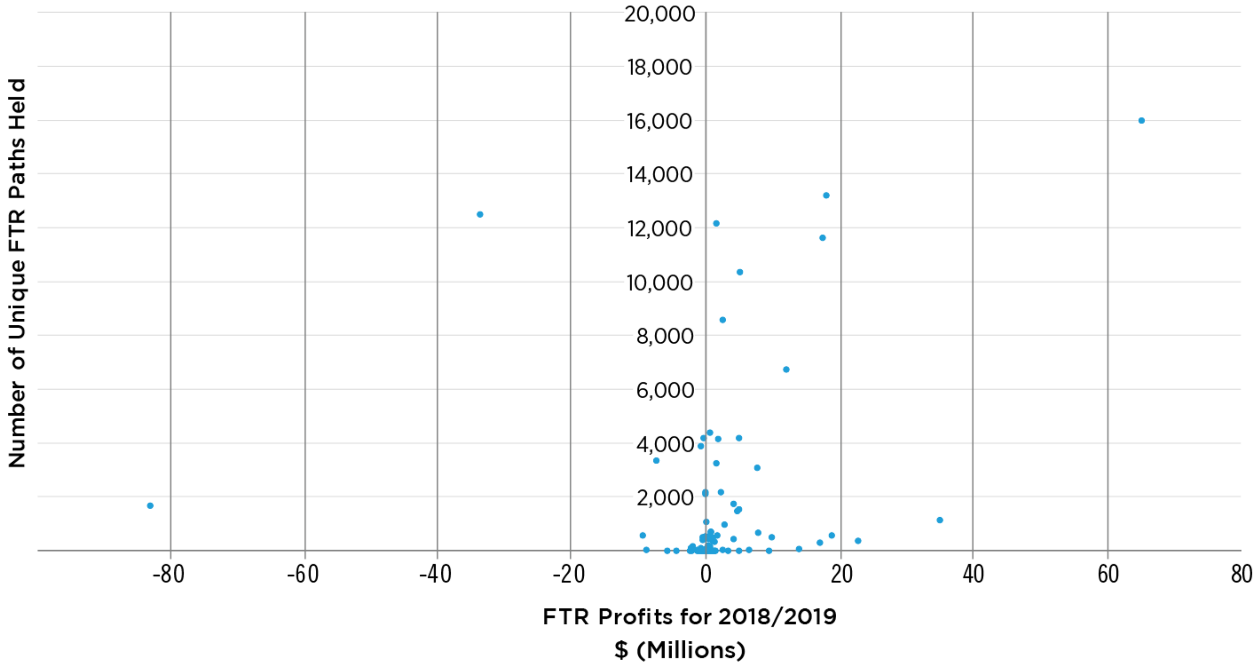
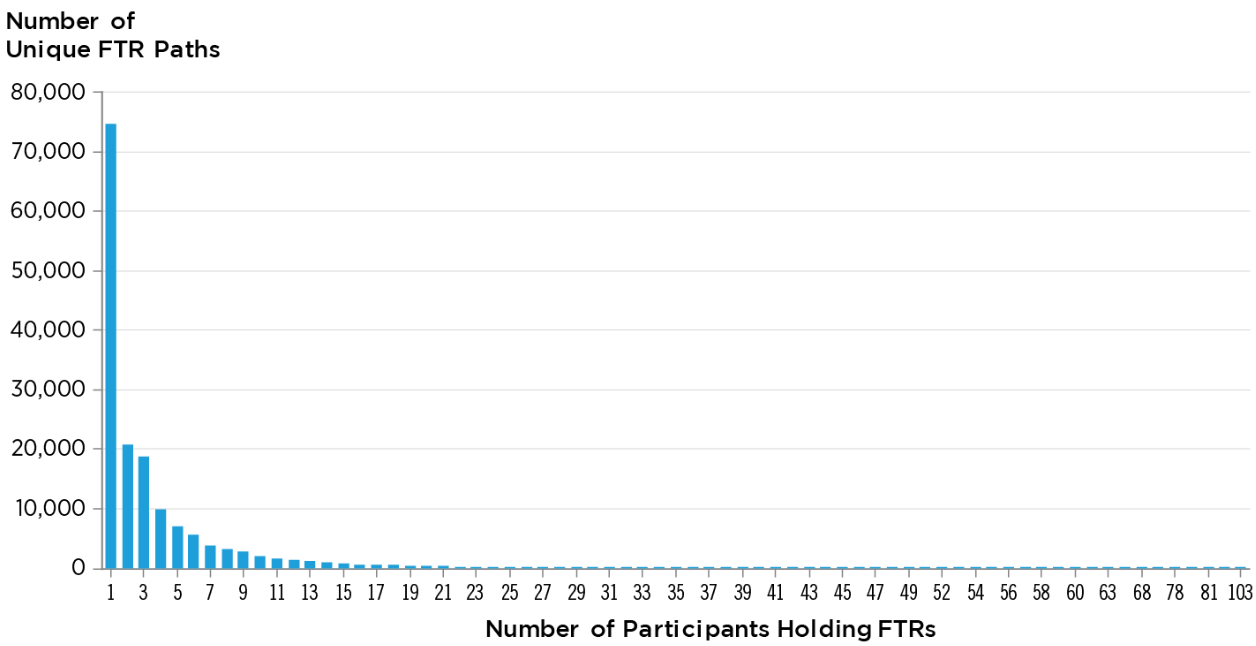
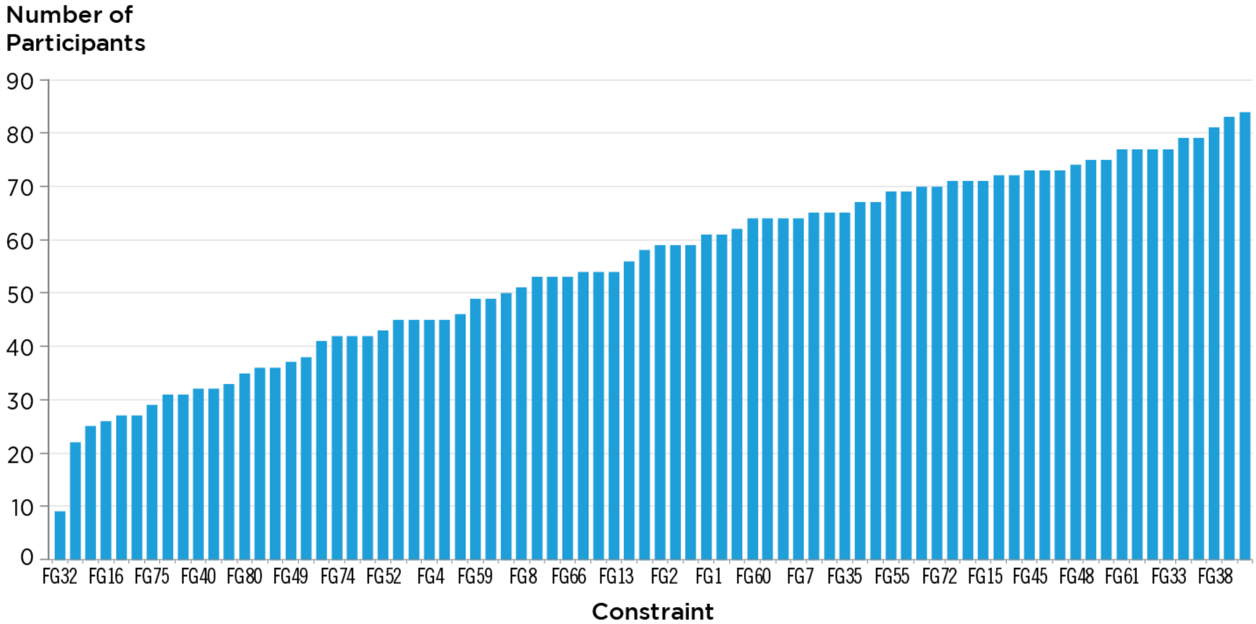


Figure 15. **2018/2019 Annual Auction Count of Unique FTR Paths by Participant**



While the connection of profits to unique paths will be explored in the stakeholder process, constraint liquidity is also something that should be examined. FTR activity must be determined on a constraint-by-constraint basis in order to determine what constraints are liquid, and hence provide value to firm transmission customers utilizing FTRs across physical delivery paths. Although there are a significant amount of unique FTR paths being held, preliminary analysis indicates, as demonstrated in Figure 14, that on a constraint basis, there are no constraints with fewer than nine market participants active from an 2018/2019 Annual Auction study.

Figure 16. **Constraint Liquidity in the 2018/2019 Annual Auction**



V. Recommended Areas to Explore

While there are strong indications that the ARR/FTR market is functioning well and providing value based on the original intent, PJM believes that there are several areas that can be explored for potential enhancements. These areas, along with others, will be discussed with stakeholders at the new ARR/FTR Market Task Force.

Investigate Existing ARR Construct

As shown previously, there may be load customers in certain transmission zones in the PJM footprint that are not able to effectively hedge their congestion costs given the existing ARR/FTR construct. A potential root cause of this could be a misalignment of ARRs and actual congestion costs incurred. The current historically based allocation construct has been in place for many years, and may need to be revisited to align with existing energy deliveries. In particular, the geography and capacity of certain ARR resources should be investigated in order to determine whether or not they can be better aligned with actual system usage. Additionally, the total system capability allocated to ARR holders needs to be explored to ensure these holders have first rights to the transmission system. PJM and the IMM have agreed to pursue these conversations further through the stakeholder process in 2020.

Evaluate Biddable Points

PJM believes that another potential area to explore is the value added by the existing set of FTR biddable points. Currently, over a million combinations of biddable points are available, although most are not utilized. There are some areas of concern that come with such a large pool of potential source/sink combinations. First, establishing a modeling approach to evaluating initial margin requirements becomes extremely complex, due to the number of paths that would need to be evaluated. Additionally, having over a million combinations promotes the ability for more sophisticated traders to isolate and purchase potentially illiquid paths. These areas of concern must be thoroughly explored, and such investigations should include an evaluation of both the costs and benefits of the existing set of biddable points.

Review Value of Existing Incremental ARR (IARR) Products

PJM currently offers several IARR products for those seeking to add transmission capability either through elective upgrades or a merchant transmission project. The FTR group spends significant time and resources throughout the year building these models, although very few study requests are made. However, since 2016, only six requests have been studied by the FTR group with each study taking about one week to complete. Due to simultaneous feasibility constraints, none of these six requests have resulted in IARRs awarded to the participant. Additionally, many IARR requests are made with no intent to actually provide transfer capability to the transmission network, but rather to acquire a potential high-value IARR with low-cost ineffective upgrades. The IARR products should be reevaluated and enhanced or mitigated, where possible.

Consider Bilateral Market Reform

FTRs purchased in the auctions can be sold bilaterally to another PJM member through the FTR center system. While there are rules for indemnification of any default and corresponding ownership rules in the PJM governing documents, these provisions can be enhanced to better protect PJM and the membership from potential market manipulation. Rules governing bilateral transactions should be enhanced through the stakeholder process in 2020.

Additional Interests From the AFMTF

At its March 25, 2020 meeting, the ARR/FTR Market Task Force held an interest identification session to document the concerns from stakeholders behind potential positions to maintain or reform the status quo. A full list of the wide-ranging interests can be found here.

VI. Conclusions and Next Steps

PJM believes the ARR/FTR product is functioning as intended, and the existing point-to-point construct is fundamental to its design as well as the operation of the energy market. PJM also believes the long-term auction and financial participation in the FTR market is important. However, it would be appropriate to evolve the product in several ways. First, PJM agrees with the IMM’s recommendation to enhance the ARR allocation process. Better methods may exist to enhance the alignment and quantity of rights to congestion on a forward basis with actual congestion revenues. Second, PJM agrees to explore potential changes associated with available source or sink points in FTR auctions. Such changes could be consistent with PJM’s recommendation for virtual transactions as discussed in the PJM whitepaper entitled “Virtual Transactions in the PJM Energy Markets.” In this paper, PJM recommended aligning the points at which virtual trading is allowed with points at which actual, physical market activity is settled together with trading hubs. These recommendations were ultimately adopted by FERC. These recommendations and others highlighted above should be pursued immediately in the stakeholder process.