Review of PJM's Auction Revenue Rights and Financial Transmission Rights

LONDON
ECONOMICS

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Acronyms

Acronyms	Description
APNode	Aggregate Pricing Node
ARR	Auction Revenue Rights
BGS-RSCP	Basic Generation Service - Residential and Smaller Commercial Customers
BOPP	Balance of Planning Period
BRSS	Baseload Reserved Source Set
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
CARRs	Candidate Auction Revenue Rights
CLMP	Congestion component of LMP
CONE	Cost of New Entry
CPNodes	Commercial Pricing Nodes
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zones
CRRs	Congestion Revenue Rights
CSCs	Commercially Significant Transmission Constraints
DAM	Day-Ahead Energy Market or Day Ahead
DER	Distributed Energy Resource
DMM	Department of Market Monitoring
EDCs	Electric Distribution Utilities
EIM	Energy Imbalance Market
EPAct2005	Energy Policy Act of 2005
EQR	Electric Quarterly Reports
ERCOT	Electric Reliability Council of Texas
ETC	Existing Transmission Contracts
FERC	Federal Energy Regulatory Commission
FGDs	Focus Group Discussions
FNM	Full Network Model
FTR	Financial Transmission Rights
Gen2gen	Generator-to-generator
GFAs	Grandfather Agreements
GW	Gigawatt
HUFU	High Utilization Factor Unit
IARRs	Incremental ARRs
ICE	Intercontinental Exchange
IFM	Integrated Forward Market
ILTTRs	Incremental Long-Term Transmission Rights
IMM	Independent Market Monitor
ISO	Independent System Operator
LADWP	Los Angeles Department of Water and Power
LAP	Load Aggregation Point

LDES	Louis Dreyfus Energy Services
LEI	London Economics International LLC
LMP	Locational Marginal Pricing
LSEs	Load Serving Entities
LT	Long-Term
LT FTR	Long-Term FTR
LTTR	Long-Term Transmission Right
M2M	Market to Market
MIS	Market Information System
MISO	Midcontinent Independent System Operator
MPMA	Multi-Period Monthly Auction
MRTU	Market Redesign and Technology Upgrade
MSC	Market Surveillance Committee
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MW	Megawatt
NITS	Network Integration Transmission Service
NOIEs	Non-opt In Entities
OBAALSEs	Out-of-Balancing Authority Area LSEs
PJM	PJM Interconnection
PNP	Priority Nomination Process
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRSS	Peak Reserved Source Set
PTP	Point-to-point
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
PY	Planning Years
QRR	Qualified Replacement Resources
QSEs	Qualified Scheduling Entities
RA	Resource Adequacy
REs	Resource Entities
RFO	Request for Offers
RFP	Request for Proposals
RSPs	Reserved Resources Points
RTC	Real-Time Co-optimization
RTCIO	Real-time Congestion Imbalance Offset
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard and Poor's
SFT	Simultaneous Feasibility Test
SMUD	Sacramento Municipal Utility District
SOM	State of the Market

SPP	Southwest Power Pool
SRS	Secondary Registration System
SS	Self-Scheduled
TCM	Transmission Customer Metric
TCR	Transmission Congestion Rights
TDSPs	Transmission and/or Distribution Service Providers
TO	Transmission Owners
TOR	Transmission Ownership Rights
TOU	Time of Use
UDCs	Utility Distribution Companies
VIUs	Vertically Integrated Utilities

1 Executive Summary

London Economics International LLC ("LEI") was engaged by PJM Interconnection LLC ("PJM") in August 2020 to provide an independent assessment of PJM's financial transmission rights ("FTR") market and auction revenue rights ("ARR") mechanism. The key objective of this engagement is to determine if the current ARR/FTR processes employed by PJM, including the ARR allocation and FTR auctions, constitute the appropriate mechanism by which to ensure that load[1] is adequately compensated for the value of to the transmission system, which it is paying through regulated transmission access charges. FTRs are financial contracts that market participants acquire through FTR auctions to receive the congestion price of a specific path defined by a source and sink node. The congestion price is not known until after settlement of the day-ahead energy ("DAM") market. ARRs, on the other hand, are entitlements that load receives free of charge. ARRs entitle the holder to receive the FTR auction revenues associated with the specific path. ARR holders can also convert their ARR into an FTR by self-scheduling in the annual FTR auction.

Figure 1. Key questions to be addressed in this engagement

Scope of Analysis for ARRs and FTRs

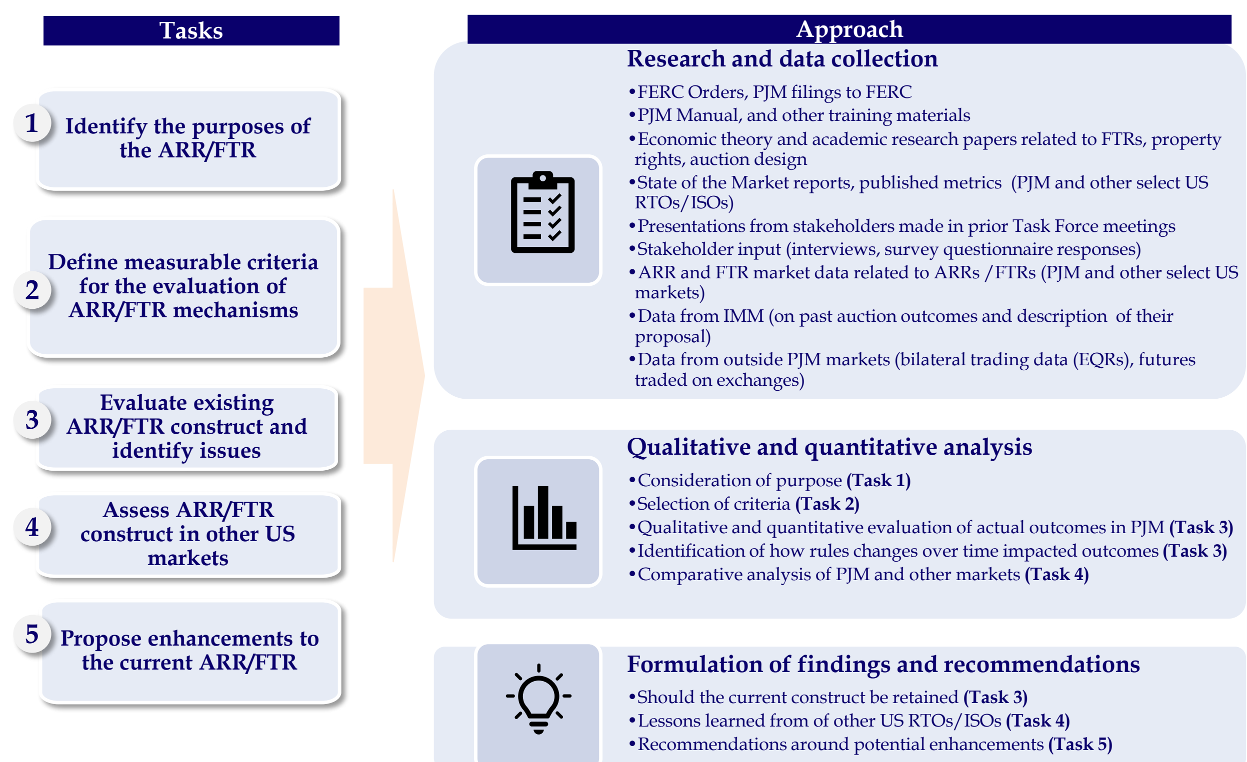
- **For what purpose were they initially created? Was it to address a problem?**
- **Are they fulfilling, in the best way possible, their initial purpose and/or addressing the identified problem?**
- **If not, why not? If so, how is this measured and verified?**
- **Is this purpose still required and if it is addressing a problem, are there alternative ways to eliminate the problem entirely?**
- **Are there additional purposes and/or sources of value to the market that ARRs and FTRs are, or should be, fulfilling or delivering? If so, what are these purposes, how do they optimize value to load and other market participants; and how is this value optimization measured and verified?**
- **What other mechanisms, either inside or outside the RTO, can provide alternative ways to achieve some of these purposes? If such mechanisms exist, can they work alongside each other or as variations to current mechanisms to optimize value to load and other market participants?**
- **Are there changes in market design, execution or product tenor that would improve delivery of these instruments' purposes, either through increased efficiency, greater equity, a better optimized delivery of value or lower risk to load, or in some other way?**

[1] In this report, load is used to mean end-use customers and other firm transmission customers.

PJM asked that LEI address seven key questions, which are listed in Figure 1. The answers to these questions are provided at the end of this Executive Summary.

LEI employed a research-based approach to address these fundamental questions, leveraging quantitative and qualitative methods of analysis. The work plan was divided into five tasks, which are depicted in Figure 2. Task 1 starts with the identification of the original rationale or purpose of the ARR and FTR mechanisms. Task 2 presents the evaluation criteria LEI selected to assess the ARR/FTR construct. As mandated by the terms of reference, LEI focuses its analysis on the existing ARR/FTR design in Task 3, using the selected criteria from Task 2 and given the purpose(s) identified in Task 1. In addition to gathering feedback from PJM stakeholders, the Independent Market Monitor ("IMM"), and PJM staff as part of Task 3, LEI also compared PJM's ARR/FTR design with the mechanisms used in three other US power market (Task 4). Lessons learned from other jurisdictions, input from PJM stakeholders, and LEI's independent findings in Task 3 provide the basis for LEI's recommendations and suggested enhancements (Task 5).

Figure 2. LEI's approach to this engagement



1.1 Identifying the purpose of the ARR/FTR mechanisms (Task 1)

Based on LEI's independent research, there are two purposes to the ARR/FTR mechanisms:

- Purpose #1: Facilitate the return of overpayment in locational marginal prices ("LMP") (known as congestion charges) back to load; and

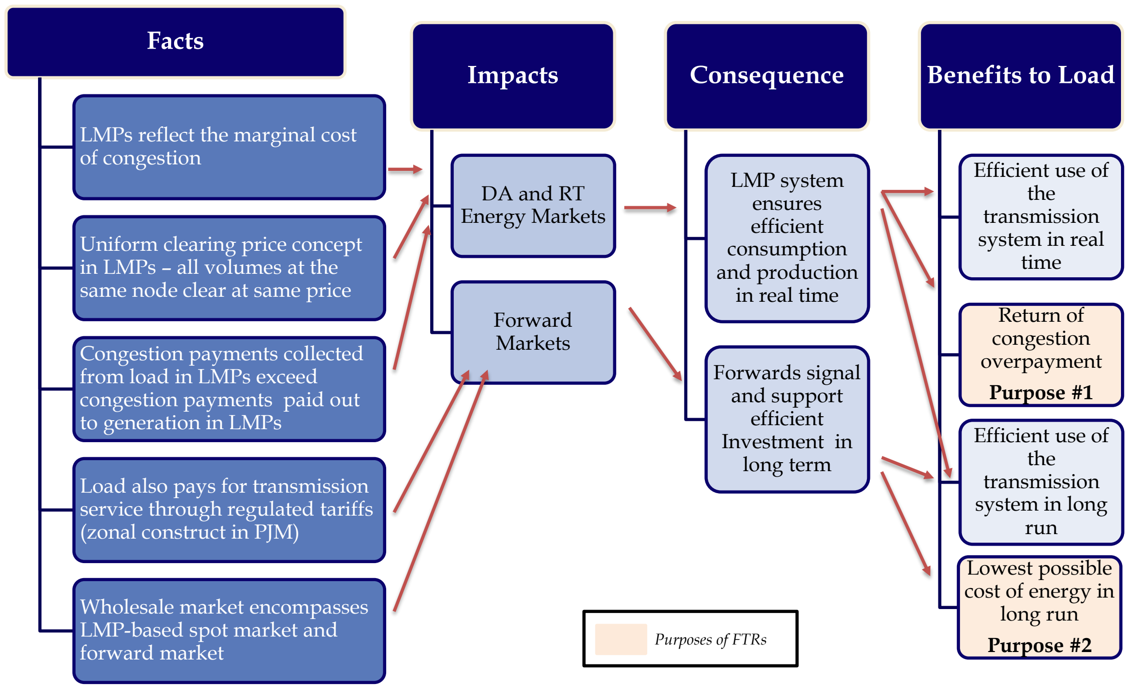
- Purpose #2: Enable hedging of the marginal cost of congestion in LMPs between different nodes and support forward market activity through the offering of FTRs.

FTRs were created as a consequence of the decision to implement LMP in energy spot markets. The use of an LMP design with open access ensures the efficient allocation of transmission network capacity and, as a result, efficient production and consumption decisions in the short term. LMP outcomes can also provide a location-specific market signal to investors to encourage new generation investment and indicate opportunities for transmission investment to ease grid congestion.

However, the LMP system also has a drawback – it results in a situation of overpayment by load when the transmission system is congested. When a transmission interface is binding, and the last increment of demand in import constrained areas must be met with local (higher priced) generation resources. All load in the import constrained area pays the higher LMP, even though some of the energy being consumed comes from lower-priced resources outside the local area. The local generator gets paid the higher LMP, but the external resources get a lower LMP, commensurate with their marginal costs of production. Due to transmission congestion and the uniform pricing principles, the system operator will collect more dollars from load than it pays out to generators, resulting in what is known as "congestion charges." These congestion charges are surpluses, as they are not needed to compensate generators for their energy or remunerate transmission owners. Load should be paid these congestion charges because they have already paid for the transmission system (via regulated tariffs). Therefore, the first purpose of FTRs is to facilitate the return of congestion charges back to load, as suggested in the figure below.

Based on LEI's independent analysis, and consistent with the positions taken by market rules at other Independent System Operators ("ISOs"), the return of congestion charges is *not* the *only* purpose of FTRs. Although FTRs are settled vis-à-vis the day-ahead energy market, it is important to recognize that the spot market for energy is not the only platform for buyers and sellers to transact energy. Indeed, the path-based construct for the FTR auction was selected originally by the PJM Companies and approved by the Federal Energy Regulatory Commission ("FERC") to accommodate other commercial arrangements (such as bilateral contracts and self-supply arrangements) that market participants enter into in the forward market (or as a consequence of the regulatory construct). The forward market continues to be a critical element of the overall wholesale energy market design to support the investment signal and re-allocate (hedge) the market price risks associated with a volatile spot market price. FERC recognized that bilateral transactions would continue to exist, even after LMP systems were implemented. FERC also understood that the marginal cost of congestion in LMPs would be very volatile and difficult for market participants to hedge using bilateral contracts. Therefore, the FTR instrument was created as a way for buyers (on behalf of load) and other market participants to hedge that volatile congestion cost component of LMPs.

Figure 3. Why do we need FTRs?



How does the hedging work? A load serving entity ("LSE") that has a bilateral contract with a generator can use an FTR that is based on a path that is defined by the source node of the generator and the sink node(s) associated with its load to create a "perfect hedge" against the congestion cost associated with that bilateral contract. Hedging can also be accomplished using financial instruments that are constructed based on the information released by the FTR markets. More generally, when FTRs are auctioned, market participants get a very granular perspective on expected congestion on the system. This information influences a variety of hedging strategies and bilateral purchases and sales. In this way, FTRs can provide an important link between LMP-based spot markets and forward markets, and therefore contribute to sustainable, competitive wholesale electricity markets in the long run. Figure 3 above contains a diagram illustrating the various basic facts that drive the need for FTRs. The diagram also maps out which segments of the wholesale electricity market are impacted, the consequences, and the resulting benefits to load. As indicated by arrows in the diagram, the ARR/FTR mechanisms create benefits for load over both the short-term (Purpose #1) and long term (Purpose #2).

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Although the FTR/ARR rules have evolved since their inception in PJM, the initial purposes for having FTRs remain valid today, as load continues to pay for transmission service separately from the spot market for energy, and the importance of bilateral contracting has not diminished. In other words, the overall market design continues to depend on an efficient spot market and a liquid and well-functioning forward market, which ensures that the load gets the lowest possible cost of energy.

Task 1: Based on LEI's critical review of relevant PJM filings and FERC Orders from 1996 through the present day, FTRs (and ARRs) serve two purposes:

#1: LMP payments made by load exceed the spot market payments to all generators in an LMP system when there is congestion. ARRs/FTRs facilitate the return of this overpayment. LMPs must include the marginal cost of congestion to ensure efficient use of the transmission network in the short term, but the "overpayment" by load is surplus, that is not needed for compensating transmission owners or generators. Load has already paid for transmission service through regulated rates. Load should therefore receive this surplus. Return of the congestion charges benefits load as it reduces the overall cost of delivered power in the short term.

#2: FTRs allow for hedging of the marginal cost of congestion in LMPs between different nodes and support forward market activity. FTR auction results also provide a granular understanding of expected network congestion. With this information, market participants can more effectively contract and hedge market price risk, which supports generation investment. Price discovery also encourages more activity in the forward market, which in turn reduces the transaction costs of hedging and bilateral contracting. In the long run, load benefits from liquid and efficient forward market through lower cost of supply.

1.2 Selecting the appropriate evaluation criteria (Task 2)

Any rigorous analysis should begin with a set of objective criteria. These criteria need to be relevant to the problem being analyzed and should be unbiased and measurable. To analyze PJM's ARR/FTR mechanism, LEI selected four criteria -- equity, efficiency, simplicity, and transparency. These are commonly used criteria in regulatory economics and policy design. Furthermore, equity and efficiency criteria relate directly to the identified purposes of FTRs (and ARRs):

- equity considerations are the fundamental rationale for seeking to return congestion charges to load, given the congestion charges represent an "overpayment" and load has already paid for the transmission system through a separate regulated tariff; and

- efficiency considerations are key factors behind realizing both the short-term and long-term benefits of the transmission system. In the short-term, efficient FTR auctions ensure that the ARR construct is a reasonable mechanism for the return of congestion charges back to load. And while the LMP systems ensure short-term operational efficiencies are achieved, the long-term efficiency of the wholesale market – characterized by appropriate levels of investment and convergence to long-run marginal costs – can be achieved only if the LMP-based spot market and forward market are aligned.

Transparency and simplicity criteria play a supporting but vital role, as recognized by many market designers, policymakers, and regulators. Transparency supports accountability and efficient outcomes, but also emphasizes the acceptability of these outcomes, a key condition for achieving an equitable effect. Simplicity ensures that administrative burdens are reduced, and transaction costs are minimized.

There is some level of interplay between the equity and efficiency criteria and between Purpose #1 and Purpose #2. Some critics of the current design point out that the current FTR auction design involves "leakage" of some congestion charges (in the form of net profits to non-load entities participating in the FTR auctions). The term "leakage" is used because some of the congestion charges go to remunerate non-load entities, and therefore load gets a reduced amount returned (Purpose #1). If we focus on just equity considerations and Purpose #1, this leakage could be a major concern, and we would likely conclude that there are major shortcomings in the current design. But as we discuss further in Section 6, this leakage needs to be considered in light of the benefits associated with Purpose #2. In a holistic framework, the net congestion charges paid out to non-load participants should be viewed as a cost offset to the long-run benefits that are motivated by efficient FTR auctions. Non-load participants support forward market activities that benefit load. Another way to view this leakage is to consider it as a form of an insurance premium for hedging and a catalyst for a liquid and efficient forward market. Therefore, it is important to ensure that any proposed enhancements to increase the short-term benefits under Purpose #1 do not suppress the long-run benefits associated with Purpose #2.

Task 2: LEI selected four criteria for evaluating PJM's ARR/FTR mechanism:

- **Equity** – reflects the fair treatment of affected parties (for example, equitable distribution of benefits or profits from the purchase/sale of a good or service);
- **Efficiency** - involves the optimal allocation of resources to those that value them the most;
- **Transparency** -indicates a condition whereby every market participant has timely access to relevant information for purposes of decision-making in an auction or regulatory context; and
- **Simplicity** – manifests in a notion that simpler theories should be preferred to more complex ones, so long as the simplicity does not compromise the functionality of the mechanism.

1.3 Evaluation of the current ARR/FTR design (Task 3)

For Task 3, LEI assessed the functionality of the current ARR/FTR mechanism and studied how each feature of the mechanism works within the ARR/FTR system and as part of the broader wholesale electricity market design. LEI also canvassed PJM stakeholders about their views on the existing ARR/FTR mechanism's advantages and disadvantages. As part of the stakeholder engagement, LEI received input on proposed modifications to address the perceived shortcomings and enhance the identified strengths.[2] LEI also interviewed the IMM and PJM staff and gathered data relating to the operations of the ARR process and FTR auctions, as well as ideas for potential changes.[3]

1.3.1 ARR/FTR mechanism changes have improved the functionality of the mechanism in respect of the intended purposes

From the point of inception, FTRs (and ARRs) were designed to be path-based (or point-to-point) property rights (entitlements). This design choice was made intentionally: to accommodate bilateral contracts and align with how bilateral or self-schedule trades are settled in the LMP market. The point-to-point definition of FTRs (and ARRs) allows market participants to hedge their exposure to LMP differences between the designated source and the location of the delivery point/load. The use of path-based property rights has not changed over the years.

In contrast, there have been multiple changes to other elements of the FTR (and ARR) mechanism. Initially, PJM allocated FTRs directly to network and firm point-to-point transmission customers. An FTR auction process was introduced in 1999 to allow PJM to sell unassigned FTRs and facilitate the trading of FTRs among all market participants. This was an important change in that it ensured the efficient allocation of FTRs to those that valued them the most and thereby improving the efficacy of both the allocation of the FTRs and the hedging process. In 2003, PJM created another property right – ARRs. ARRs were allocated to transmission customers (load) and could be converted to FTRs or otherwise retained to collect FTR auction revenues. ARRs gave load greater flexibility on how to hedge (and when to securitize) congestion charges in LMPs. PJM also added an annual FTR auction in 2003 to support additional trading opportunities and institutionalize the connection between the two property rights (LSEs could convert their ARRs into FTRs in the annual FTR auction).

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[2] LEI understands that PJM is separately pursuing changes to credit rules. Therefore, this area is not covered in the present study although LEI recognizes this as an important issue in its own right.

[3] In addition to information on the operational dynamics of the ARR allocation process and results of past FTR auctions, LEI also collected bilateral contract data (from FERC's Electronic Quarterly Reports) and forward markets data (from the Intercontinental Exchange ("ICE") and Nodal Exchange).

Once the dual system of property rights was implemented, additional modifications followed. Figure 4 lists the major changes since 2003 and the impact they had on the intended purposes. Each change reinforced either Purpose #1 or Purpose #2 (or both).

Figure 4. Major changes since 2003 and the impact they had on the intended purposes

	Key Changes	Impact
1	Revision of the allocation process to include a Stage 1A and 1B	Provides more certainty (priority) to load regarding their long-term rights in network (Purpose #1)
2	ARR allocation mechanism was adjusted to reflect the changing generation fleet	Improves effectiveness of ARR allocation process (Purpose #1)
3	ARR mechanism was expanded to address transmission capability created through merchant transmission investment	Refines the investment signal emanating from ARRs (Purpose #2)
4	FTR auction design was modified (e.g., introducing monthly and long-term auctions) and the universe of FTR products was expanded	Provides additional opportunities to reconfigure FTR portfolios and hedge (Purpose #1) Improves price discovery (Purpose #2)
5	Allocation of balancing congestion costs was changed to solve the overpayment issue to FTR holders	Improves payout to load (Purpose #1) Pricing in FTR auctions no longer reflects risks of balancing congestion; more reflective of expected congestion in the day-ahead energy market (Purpose #2)
6	Payment of surplus congestion was shifted from FTR holders to ARR holders	Improves payout to load (Purpose #1)

1.3.2 Most stakeholders affirmed their general satisfaction with the current ARR/FTR design

As part of the stakeholder initiative, LEI engaged with 37 entities involved[4] with PJM's ARR allocation process and FTR markets, including LSEs, generation owners and independent power producers ("IPPs"), and other types of entities (trading organizations, energy service providers, and customer advocacy groups). The stakeholder engagement process consisted of: (i) four focus group discussions ("FGDs"); (ii) a follow-up questionnaire-based survey; and (iii) one-on-one discussions.

Based on the feedback and commentary elicited from the stakeholders, LEI observed that most FTR auction participants were satisfied with the current FTR auction design and range of

[4] Or representing entities who are involved with ARRs/FTRs.

available FTR products. There was also a general agreement that the current ARR/FTR market design provided adequate opportunities for hedging and managing the risk of congestion for load and other market participants. Stakeholders that actively trade in the FTR auctions also stressed that FTR auction outcomes provided valuable price discovery for various forward market activities.

Nevertheless, some LSEs expressed concern that the existing ARR allocation process was inadequate. In particular, these LSEs felt the quantity of allocated network capacity in the ARR process, and the range of ARR products (specifically, the ARR paths vis-à-vis the paths available in the FTR auctions) was deficient. In addition, some expressed a belief that the current ARR mechanism did not enable customers to access the resource paths needed to hedge the congestion risk relative to their contracted resources (new generation in particular). Furthermore, there were also concerns with the complexity and transparency of the network model that PJM used to test the simultaneous feasibility of ARR requests and bids/offers in the FTR auctions.

Overall, most stakeholders expressed a preference for incremental improvements and enhancements rather than a complete overhaul of the ARR/FTR market design. The potential points of enhancements and modifications suggested by stakeholders to target shortcomings in the ARR/FTR design include changes to the ARR allocation scheme and increased FTR granularity (especially if it could align with the operational profile of intermittent energy sources). Some stakeholders also suggested reservation prices or other changes to ensure the value of network capacity sold in the FTR auctions is maximized for the benefit of load holding onto ARRs. These recommended enhancements focused primarily on Purpose #1. Several stakeholders also noted that they have had to restrict their activity (with respect to virtual bidding or FTR auction participation) due to the current FTR forfeiture rule.[5] Changes to the forfeiture rule may affect both Purpose #1 and Purpose #2 because it may motivate more FTR auction activity (competition may assist in optimizing the value of ARRs), support hedging, and assist with the convergence of the day-ahead and real-time markets (to the extent that the relaxation of the forfeiture rule would increase virtual trading activity).

1.3.2.1 IMM would like to move away from the current ARR/FTR design

The IMM has advocated for a comprehensive redesign of the ARR and FTR construct. In simple terms, the IMM would like to see the current dual property right system replaced with a new property right, which they refer to as a "network congestion property right." In essence, the IMM proposal is a single property right system where only load would receive distribution of congestion charges collected by PJM through the operation of the day-ahead and real-time energy market. The IMM's network congestion property right concept is different from the current ARR/FTR mechanism in the following ways (as listed in Figure 5):

[5] The FTR forfeiture rule is designed to prevent market participants from using virtual transactions to create congestion that benefits their related FTR positions. FERC Docket NO. EL14-37-000.

- it is not modeled on a path-based or point-to-point construct: there is no specific "source" point, although the sink is always the bus or load zone relevant for each LSE;
- there is no ARR allocation process, and therefore no need for network modeling - load will simply hold a right to receive a set of payments based on total spot market congestion charges; those payments would be distributed to LSEs using the IMM's constraint-based congestion calculation methodology, which relies on assessing the pattern of energy flows in the spot market;[6] and
- there is no compulsory ex-ante auction – therefore, there is no simple way for load to monetize[7] the value of the IMM's network single property right system ahead of the spot market.

In discussions with LEI, the IMM acknowledged the value of trading and noted that load would be free to sell their network congestion property right ahead of spot market settlement. The IMM believes a transactable platform can be developed, and it would not necessarily need to be administered by PJM (e.g., trading could be supported by a third-party exchange). However, it is unclear how liquid and efficient the sale of network congestion property right would be (especially if only *some* LSEs sell their network congestion property right). Therefore, the inherent design would create complications for establishing the market value and trading of the IMM's network single property right product. Indeed, given the focus of the IMM's proposal is exclusively on Purpose #1 (and specifically to design a mechanism that returns *exactly* 100% of congestion charges back to load), the lack of details on how a network congestion property right could be sold and bought is not surprising. The IMM also realizes that its proposal would require significant retooling of how the industry uses the information from FTR auctions to support forward markets and how market participants use the existing FTR product to hedge congestion risk associated with bilateral contracts. Figure 5 provides a high-level comparison of the current mechanisms and the IMM's proposal.

LEI has concerns that the IMM's proposal is novel and uncertain. Moreover, because the IMM's network congestion property right concept is designed specifically (and solely) for Purpose #1, there will be disruption to commercial activity (at the very least) and possibly unintended longer-term consequences that would undermine the attainment of Purpose #2. Further investigation and prototyping of the network congestion property right construct is necessary. For these reasons, LEI does not support moving forward with the IMM's proposal at this time.

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[6] PJM IMM. "Constraint Based Congestion Calculations: Measuring Congestion Paid by Zone." June 22, 2020.

[7] When load monetizes the congestion charges under the existing design, they are essentially entering into a fixed for variable swap (e.g., exchanging the variable congestion costs they would receive from the day-ahead energy market for a fixed payment based on the FTR auction results).

Figure 5. Key differences between the current mechanisms and IMM's proposal

Feature	Current mechanism	IMM's network congestion property right
Property transmission system	Dual property system	Single property system (No ARR)
Construct	Path-based with a source and a sink	No specific "source" point Sink is either bus or load zone
Allocation of the ARRs/FTRs	ARRs are allocated through ARR allocation process FTRs can be bought through the FTR auctions	Load receives the network congestion property right based on IMM's methodology of examining network constraints in the spot market
Value of ARRs/FTRs	Based on the ARR/FTR target allocation or the difference between the LMP of the source and the sink in the auction (for the ARR) and the day-ahead market (for FTR)	Value of the network congestion property right known only after settlement of spot markets; LSEs can sell their network congestion property right in advance if they desire

1.3.3 Assessment of the existing mechanisms with respect to Purpose #1

Using actual ARR and FTR settlements as well as congestion charges, LEI analyzed whether the current ARR/FTR mechanisms provided a return of congestion charges back to load. A detailed examination of actual outcomes from the 2011/12 planning year through the 2019/2020 planning year confirms that, on average, 83% of congestion charges collected in the PJM spot market were returned to load, as illustrated in Figure 6. Notably, FERC never specified in its original decisions that it expected the FTR construct (and ARR mechanism, once that was approved) to return *exactly* 100% of congestion charges back to load each year.[8] A large portion of the variability year-over-year in the percent of congestion charges returned to load is contingent on weather. The average ratio is much higher (over 90%) if we exclude the years with unusual weather events. Furthermore, it is important to note that since the rule change around surplus congestion, effective in the planning period 2018/19, the ratio of congestion charges returned to load has increased.

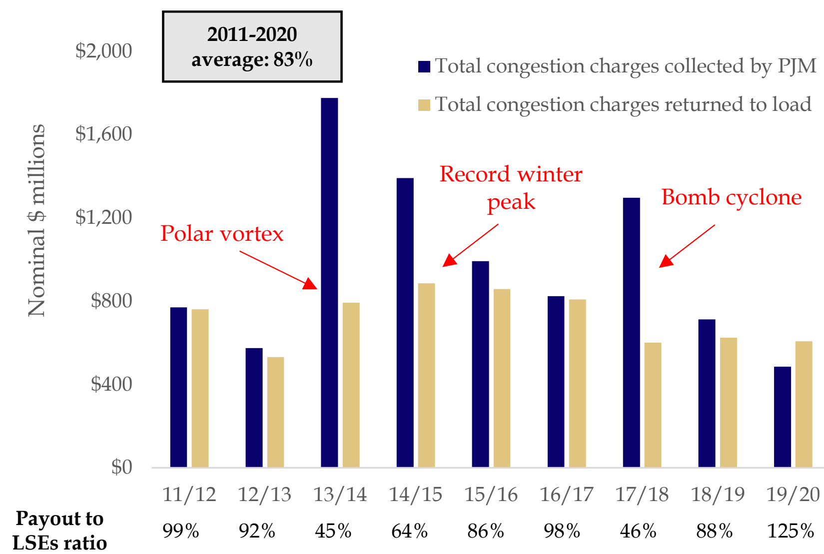
The dual system of path-based property rights, where ARRs are allocated in advance, and FTRs are auctioned off on an ex-ante basis to day-ahead energy markets, could create over-or under-payment of congestion charges to load. Since transmission network capacity is finite, PJM has to estimate the amount of network capacity to allocate (in the ARR process) and sell (in the FTR

[8] Indeed, in the 2016 Order, FERC clarified that return of congestion charges was not the only objective for FTRs, which would necessitate accepting that some leakage from congestion charges is reasonable. FERC, FERC 61,093 (2016).

auctions). In assessing the network capacity, PJM has to consider how to prevent ARR/FTR underfunding.[9] More specifically, in order to avoid underfunding issues, PJM has been naturally incentivized to under-allocate network capacity to load during the ARR process. Such under-allocation results in lower congestion charges returned to load relative to those that PJM collected. However, as noted above, recent rule changes have improved the efficacy of the ARR/FTR construct in this regard.

Planning years with significant underpayment (as illustrated by a blue bar much higher than the yellow bar in Figure 6) were associated with extreme weather conditions. Extreme weather is difficult to predict, but when it arises, actual congestion charges are very large. Because severe weather is difficult to predict one year in advance, the aggregate FTR auction revenues are lower than total day-ahead congestion charges, and, therefore, the ARR offsets received by load are relatively low. This observed dynamic is not an inherent flaw in the ARR/FTR mechanism, but it is a consequence of the dual system of property rights (and the decision of load to hold onto allocated ARRs).

Figure 6. Total congestion charges collected by PJM vs. total congestion charges returned to load



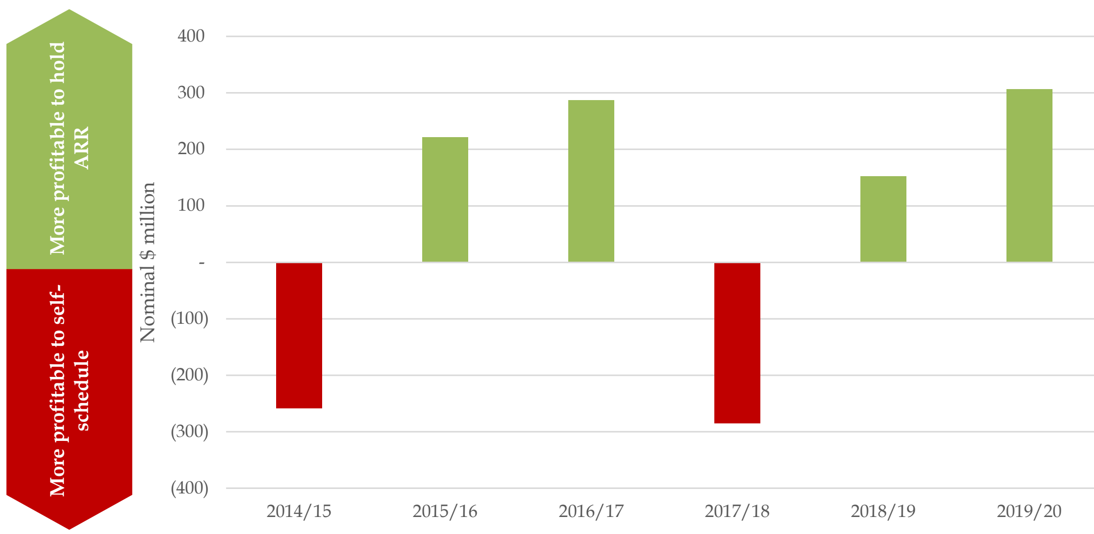
Note: It is possible that more than 100% of congestion costs are returned to load in a given year because some of the payout to load is based on the FTR auction revenues, which are driven by market expectation of congestion, and those payments could be higher than the actual congestion charges collected by PJM. "Payout to LSEs Ratio" represents congestion charges returned to load as a percentage of total congestion charges collected by PJM.

In consideration of Purpose #1, LEI also examined the reasonableness of the ARRs, which depend on the outcomes of the FTR auctions. Specifically, LEI investigated the efficiency of historical

[9] OA Schedule 1 Section 7.5a. The Office of the Interconnection shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch.

FTR auctions vis-a-vis realized congestion in the day-ahead energy market (as represented by the congestion component in LMP or the "CLMP"). All the FTR auctions – annual, long term ("LT"), and monthly – possessed statistically significant predictive power for actual CLMPs. This indicates that the FTR auctions are effective for valuing the ARRs that are held by load. In addition, this finding also means that FTR auctions can generate reasonable information for price discovery (Purpose #2). LEI also analyzed the change in the predictive power of (hypothetical) FTR auctions if financial participants were excluded (based on PJM's simulated results).[10] Statistical analysis shows that financial participation improves the predictive power of FTR auctions – this should not be surprising, given the basic tenets of finance theory and the importance of speculative trading.[11] Given that a large share of the congestion charges returned to load flow through ARRs, the efficiency of the FTR auctions (and involvement of financial participants) also supports Purpose #1.

Figure 7. Payouts from holding ARRs or self-scheduling (hypothetical example)



Note: This analysis intentionally does not include surplus allocation and balancing congestion charges. For a more detailed discussion of this analysis, please refer to Section 6.7.

Figure 7 offers a comparison on whether load would have earned greater profits if it held on to all awarded ARRs or if it self-scheduled all awarded ARRs in the annual FTR auction. Since ARR target allocation is based on annual FTR auction prices, if the auction prices had been unreasonably low, then holding ARRs would have resulted in lower payouts than self-scheduling. The analysis shows that in four out of the six most recent planning periods, load

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[10] PJM simulated a "what if" auction result for planning period 2018/19, assuming financial participants do not participate in the annual FTR auction. The result is lower FTR auction revenues as well as lower predictive power of actual congestion charges as compared to the auction with financial participants.

[11] Further discussed in Section 6.13.2.

would have received more congestion offsets if they held on to their ARRs compared to self-scheduling, and for the years where self-scheduling would result in a higher payout, those years involved extreme (and generally difficult to predict) weather events (and consequently very high congestion costs in the day-ahead energy market that would have been difficult to anticipate in the FTR auctions). This analysis shows that the ARR construct, whose value is based on FTR auction results, has reasonably remunerated load under typical conditions. Moreover, the majority of load has shown a preference for holding ARRs. This observation supports the finding that load values the ARR property right. Therefore, on an aggregate basis, we conclude that the current ARR/FTR construct is achieving Purpose #1 and that the dual system of property rights should be retained.

1.3.4 Assessment of the existing mechanisms with respect to Purpose #2

The second purpose of PJM's ARR/FTR mechanism is to support forward markets. First, we needed to understand whether there is support for price discovery, and that required us to look at the efficiency of the FTR auctions. We also needed to understand how market participants used FTR auction outcomes to hedge and support price discovery. This led us to examine the usefulness of the path-based construct for physical transactions and gather information on futures trading as well as overall forward market activity. Finally, LEI considered the potential magnitude of long-term benefits arising as a result of liquid and efficient forward markets.

1.3.4.1 Efficiency of FTR auctions

Although many traders in the FGDs talked about the connection between FTR auctions and forward markets, some stakeholders remained skeptical about the relationship and challenged us to examine evidence of the FTR connection to forward markets. Analysis of the efficiency of the FTR auctions provided the foundation for this evaluation. As described in Section 1.3.3, based on LEI's statistical analysis of historical FTR auction results (nodal prices) versus actual CLMPs, all of PJM's FTR auctions exhibited statistically significant predictive power for realized CLMPs. This is an important finding in relation to Purpose #2, as it confirms the legitimacy of a price discovery process emanating from the FTR auctions. Moreover, as noted earlier, the participation of non-load (financial) entities in the FTR auctions also improved the predictive power of the FTR auctions. LEI also discussed the business uses for each of the FTR auctions with stakeholders. The information gathered from stakeholders indicated a variety of rational and legitimate hedging and trading activities that are supported by the various FTR auctions.

To further understand the efficiency of FTR auctions, LEI also explored the profitability of FTR paths that have not been allocated to ARR holders to date (such as "gen-to-gen" paths that have a generator bus as both the source and sink point) as well as FTR options. LEI identified the realization of both large profits and large economic losses on these FTR paths. There was no evidence of systematic excess profits (on a risk-adjusted basis) for non-load entities engaging in trading these paths. Moreover, LEI found that LSEs also purchased gen-to-gen paths in past FTR auctions, suggesting that such paths are viewed as economically valuable by some load. Thus, market participants should be allowed to continue to trade these paths. Regarding FTR options, LEI found that there have been options sold at no premium over the same FTR obligation paths, indicating an illogical outcome since the option product should be more valuable given there is no downside risk. However, this issue could be fixed by adding option pricing models to the market-clearing engine.

1.3.4.2 Forward market activity

To better understand the relationship between the ARR/FTR mechanism and forward markets, LEI collected data describing forward market activity and examined how market participants engage in forward markets. First, LEI considered to what extent the path-based construct (of FTRs and ARRs) is relevant to bilateral arrangements. The path-based construct of FTRs provides an ability to perfectly hedge congestion risk at a nodal level, as FERC acknowledged when FTRs were first created. A review of transactions associated with bilateral energy contracts reported to FERC's Electric Quarterly Reports ("EQR") database shows that in the past five years (2015-2019), over 35% of the value of physical contracts with delivery in PJM used a node (instead of a hub, zone, or aggregate) as the delivery point. Transactions with nodal-based delivery points were reported to have a cumulative transaction value of over $75 billion over five years. Moreover, in the past two years, the share of transactions using nodes as a delivery point has increased to over 50% (in value terms, or $26 billion on average per annum). This fact indicates the market's overall confidence in using nodes as a commercial pricing point.

LEI next examined futures markets. A review of transaction data in the last few years for PJM basis-related futures contracts on Nodal Exchange shows a strong increase in volumes after the release of FTR auction results (and this applies to all types of FTR auctions). This is evidence of the price discovery attributes that FTR auctions provide to support the functionality of the forward market. LEI's discussions with traders active in PJM and other US power markets noted that the FTR auction design contributed to forward market liquidity. Indeed, based on total futures transacted, PJM has by far the most liquid forward market of all US RTOs/ISOs. Forward activity in PJM is also characterized by a lower bid-ask spread than other power markets. These are useful indicators of the superior liquidity of the PJM forward markets.

The extensive use of financial hedges is another measurable reference point for the importance of forward market activity in creating long term benefits to load. LEI surveyed the financing arrangements of new gas-fired resources that entered commercial operation for the last three years in PJM. LEI's research confirmed that nearly 9.5 GW of new combined-cycle gas turbine ("CCGT") capacity that started commercial operations from 2017 to 2019 involved using financial hedges as part of their financing arrangements. These financial hedges were realized thanks to liquid forward markets. Furthermore – and importantly for the purpose of estimating long term benefits – market price risk associated with the financing of these investments was reduced as a consequence of these financial hedges.

1.3.4.3 Illustrative analysis of long-term benefits associated with Purpose #2

One dimension of the long-run benefits to load due to increased liquidity and better price discovery in the forward markets can be quantified by reference to the cost of debt savings for new generation resources. A lower cost of debt translates into a lower long-run marginal cost ("LRMC") for supply. Based on the extensive use of financial hedges by new CCGT projects and information on debt financing costs from PJM's approved cost of new entry ("CONE") analysis for this technology, LEI estimates long-run benefits to load across the PJM footprint of $99 million to $318 million per year, depending on the frequency with which new CCGTs directly or indirectly affect the overall cost of supply, as described further in Section 6.13.

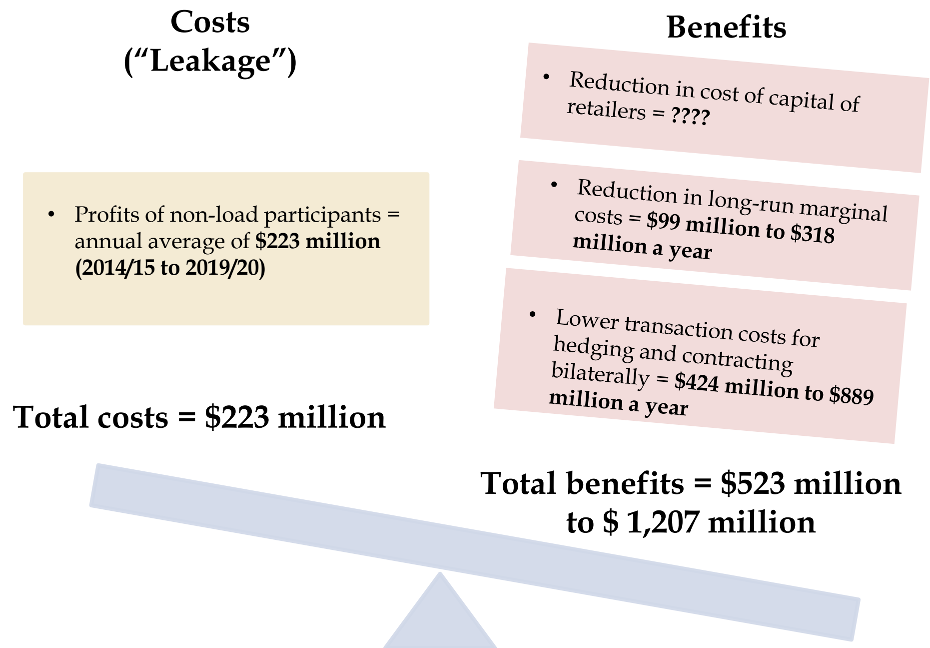
In its stakeholder engagements, LEI heard from various LSEs, including competitive retailers. It is generally recognized that liquid forward markets provide electricity retailers the opportunity to utilize hedging strategies that can significantly reduce their wholesale price exposure. A lower risk profile can reduce the cost of capital for competitive retailers over time and enhance the competitive retail offerings that they can provide to retail customers. This can benefit load in the long run, especially in a wholesale power market like PJM, where numerous areas have fully deregulated and given their customers retail choice. If a liquid forward market that provides optimal hedging opportunities for retail providers is responsible for even a small fraction of the benefits of retail competition, this is likely to be a significant benefit to electricity customers in PJM, given that over 40% of load or 315 TWh, was served by competitive retailers in 2019.

Finally, liquid forward markets also reduce the transaction costs for engaging in hedging and bilateral contracting. The "bid-ask spread" is one common indicator of the magnitude of transaction costs incurred in engaging in forward market activity. Given the overall level of physical electricity consumed and financial forward activity in PJM, even a modest increase in bid-ask spreads would raise transaction costs for the forward market. LEI estimated a transaction cost savings from PJM's relatively low bid-ask spreads in the range of $424 million and $889 million a year, as discussed further in Section 6.13. Price discovery and liquidity achieved through the FTR auctions help the forward markets avoid such transaction cost increases, which ultimately serve as another benefit to load in the long run.

The potential benefit streams for load, in the long run, are likely to be in the hundreds of millions of dollars per year. On an illustrative basis, if we add up just the hedging benefit that reduces LRMCs and transaction cost savings, we reach a total of $522 million to $1.2 billion a year for a market like PJM (and these numbers do not include consideration of retail hedging benefits). As noted in Section 1.2, the long-run benefits to load associated with liquid and efficient forward markets need to be weighed against the costs ("leakage") that arise when some of the congestion charges are retained by non-load entities in the form of net FTR profits. Figure 8 provides a summary of the illustrative benefits versus costs for load.

Over time, PJM load benefits from the existence of the forward market that is supported by the price discovery practices emanating from the FTR auctions. Therefore, although the FTR/ARR design may produce some "leakage" of benefits pursuant to Purpose #1, the FTR auctions also provide value to load in the long run, which are substantially greater based on LEI's estimates. Moreover, the size of the leakage can be further optimized with certain enhancements to the current design. For example, if load is given a choice to nominate network capacity that is currently only available to FTR buyers during the ARR allocation process and then self-schedules that network capacity into the FTR auctions, this will allow load to recapture some of the leakage amounts. In addition, changes to when and how ARR holders self-schedule their ARRs would also allow load to more finely express its willingness to potentially take on more risk and recapture some of the FTR profits that currently go to non-load entities.

Figure 8. Illustrative benefits versus costs



Note: In the two most recent planning periods (2018/19 and 2019/20), the "leakage" has averaged $120 million, because (1) with the changes in the rules, PJM has been able to allocate network capacity to ARRs more aggressively and (2) due to the absence of abnormal weather (which typically causes a significant increase in congestion charges).[12]

1.3.5 Shortcoming of the current ARR/FTR design

The major weakness in the current design is associated with the division (or distribution) of the aggregate congestion charges between LSEs. The current system of distribution of congestion payments is defined by the (i) initial allocation of gen-to-load ARRs using historical constructs that are outdated and (ii) distribution of surplus congestion that relies on the 'value' of that initial allocation of ARRs. This results in an allocation of congestion charges that may be inequitable in the eyes of some LSEs.

According to economic theory, the initial allocation of entitlements or property rights should not matter if the recipients of those rights can trade with minimal transaction costs. However, ARRs are not tradable; they are convertible to FTRs, which are then tradable. That said, the ARRs that are self-scheduled into the Annual FTR auction account for only 6% of the net FTR volumes sold in that FTR auction and 30% of the ARRs allocated. Therefore, the majority of load currently holds onto their awarded ARRs. Moreover, the value of ARRs (e.g., the "ARR target allocation")

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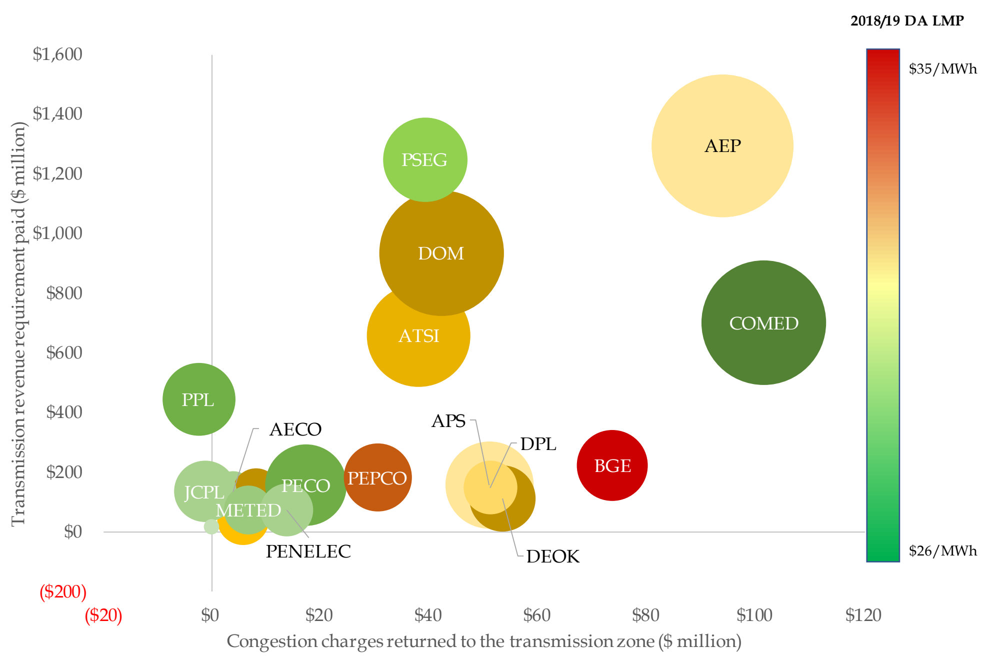
[12] Electricity demand (and therefore network congestion) has also been lower than normal in early 2020 due to the Covid-19 pandemic.

impacts not just the division of FTR auction revenues but also the allocation of surplus congestion. Therefore, the initial allocation of ARRs drives the relative payout of congestion costs to each LSE.

Based on LEI's analysis of zonal offsets received by load,[13] the current ARR allocation process creates a pattern of payments that is uncorrelated with either the size of load served, or the amount of transmission revenues collected from customers or the LMPs paid. As presented in Figure 9 (further explained below), there is no direct relationship between the amount of congestion charges returned to a transmission zone relative to the size of the load served, the transmission revenue collected, or the LMP of the zone. This indicates that congestion charges allocated to LSEs in varying zones are not correlated with any of these natural factors underlying Purpose #1, which leads LEI to conclude that there may be further issues to explore in relation to the distribution of congestion charges between LSEs.

Figure 9. Congestion charges returned to load in each zone relative to various factors (2018/19)



It would be reasonable for load to expect to receive a larger congestion offset if the LMP they face is higher than other zones (i.e., located in a more congested area in the network), if the demand in the zone is higher than the demand in other zones (which is more likely to contribute to overpayment), or if load in the zones pays a larger share of the overall transmission revenue requirement. In the figure above, each circle represents a specific transmission zone, with the size of the circle proportional to the baseload demand in the zone, the x-axis represents the congestion

[13] Zonal offsets include the totality of payments, based on ARRs and self-scheduled FTRs, as well as the settlement of balancing congestion and surplus congestion.

charges returned to the zone (which could be negative), and the y-axis represents the transmission revenue requirement paid for that zone. The color of the circles reflects the day-ahead LMP in 2018/19 planning year. In search of proof of equity of the distribution of congestion charges returned between LSEs, LEI evaluated the figure for patterns:

- if the congestion charges returned were proportional to the transmission revenue requirement paid in each zone, the circles should line up linearly – they do not;
- if the congestion charges returned were related to the demand in the zone, then the circles would be arranged in order from smallest to largest, but they do not follow this pattern; and
- finally, the redder the color of a circle, the higher the 2018 and 2019 annual average LMP recorded for the zone. If the color pattern of the circles followed a green-yellow-red "heat map" alignment, then the congestion charges returned to LSEs would be related to LMPs, but we see this is not the case.

Task 3: Summary of key findings in the evaluation of the current ARR/FTR design

- A **path-based construct**, established out of recognition of the importance of bilateral and self-supply arrangements, continues to be relevant in the present day. The majority of load continues to be served through bilaterals (and self-supply).
- A **dual system of property rights** (ARR/FTR) creates value for load. The existing ARR construct gives load a choice to hold on to an ARR (and securitize congestion charges in advance of settlement) or to self-schedule an ARR (and get a "perfect hedge" for congestion on a specific path that the LSE has committed resources and load).
- **FTR auctions are working properly and should be retained**. They are effective in achieving Purpose #1 (under normal weather conditions) and supportive of Purpose #2. Although there has historically been some "leakage" of congestion charges to non-load entities, due to participation of non-load entities in the FTR auction, these entities have positively contributed to the efficiency of the FTR auctions, and therefore enhanced the efficacy of the ARR/FTR mechanism while also allowing for price discovery in support of the forward markets.
- **Liquid and efficient forward markets bring about a number of benefits for load.** Illustrative examples suggest that the long run benefits for load are higher than the cost incurred by load (e.g., the "leakage" in congestion charges to non-load entities through FTR net profits). The current ARR/FTR mechanism, when evaluated against both Purpose #1 and Purpose #2, is creating overall positive value for load.

1.4 ARR/FTR mechanisms in other US power markets (Task 4)

LEI reviewed the FTR (and ARR) mechanisms in three other US RTOs/ISOs with the goal of identifying similarities and differences and drawing inferences about whether PJM could benefit from changes to ARR/FTR design. LEI assessed the FTR mechanisms of California ISO

("CAISO"), Electric Reliability Council of Texas ("ERCOT"), and the ARR/FTR mechanism of Midcontinental ISO ("MISO"). All these markets, in fact all US LMP-based markets, use a path-based construct for FTRs. In addition, there are a number of other similarities between the three case study markets and PJM related to the FTR mechanism. For example, all four markets settle the FTR (or equivalent) against the day-ahead energy market, specifically employing CLMPs (or equivalent). Also, all the RTOs/ISOs host auctions for the sale of FTRs (or equivalent product). In addition, the auction proceeds are paid to load. The major differences between these case study markets, and PJM relate to: (i) whether the dual (FTR plus ARR) or single (FTR-only) system of rights is used; and (ii) how those rights are distributed or sold, as shown in Figure 10.

Figure 10. Comparison of key FTR features

	CAISO	ERCOT	MISO	PJM
Nomenclature	Congestion Revenue Rights ("CRRs")	CRRs	ARR/FTR	ARR/FTR
Implemented FTR	2006	2010	2005	1998
Transmission rights system	Single system	Single system	Dual system	Dual system
Pathway to get transmission rights	• Direct allocation of CRRs to load which assigns rights to CRR auction revenue or convert and sell in the CRR auctions • Any market participant can buy CRRs in the auctions	• Direct allocation of CRR auction revenues to load • Some allocation of pre-CRRs to certain grandfathered entities • Any market participants can buy CRRs in the auctions	• Direct allocation of ARRs to load, which assigns rights to FTR auction revenue or self-scheduling in the FTR auction • Any market participant can buy FTRs in the auctions	• Direct allocation of ARRs to load, which assigns rights to FTR auction revenue or self-scheduling in the FTR auction • Any market participant can buy FTRs in the auctions
FTR auctions	• Annual • Monthly	• Annual (or Long Term) • Monthly	• Annual • Monthly	• Annual • Monthly • Long Term
Annual FTR products	• Seasonal • Peak/Offpeak	• Peak weekday/ peak weekend	• Seasonal • Peak/Offpeak	• 24-hours • Peak/Offpeak

Among the three RTOs/ISOs reviewed, MISO is the only one that has a dual property rights system like PJM. One of the biggest differences between PJM's and MISO's ARR construct relates to the ARR classes. More specifically, MISO has multiple ARR classes: it offers peak and off-peak ARRs, as well as seasonal ARRs. In contrast, PJM only offers 24-hr annual ARRs. A multi-class ARR approach may allow for more network capacity to be awarded in the ARR process if transmission outages are limited in their reduction of network capacity to just specific seasons or time periods.

CAISO and ERCOT do not have an equivalent to PJM's ARRs; they use different approaches for giving LSEs the right to get a return of the congestion charges collected through LMPs. CAISO allocates their version of the FTR product (which they call Congestion Revenue Rights or "CRRs") directly to LSEs, and then it is up to LSEs to sell the assigned CRRs in the CRR auction or hold onto the CRR and receive the associated congestion rents from the day-ahead energy market. CAISO recently implemented a change to its CRR framework, effectively reducing the paths that could be awarded or sold in the auction. Those changes resulted in a contraction of the CRR auction: cleared CRR quantities fell by 57%, and the net CRR auction revenues declined to $63 million in 2019 compared to an average of $83 million in the two prior years 2017 and 2018. Such an outcome would not be beneficial in the PJM context, as lower FTR auction revenues would mean more of the congestion charges would be picked up in surplus congestion and allocated using rules-based approaches, which may not be equitable. In addition, less auction participation may reduce the efficiency of the FTR auctions and undermine the forward markets and long-term benefits.

ERCOT does not assign CRRs to load.[14] Rather, ERCOT directly allocates the auction revenues from the sale of its CRRs to load, based on each LSE's pro-rata share of zonal and system load.[15] Notably, ERCOT has a single transmission tariff, which all load contributes to on a pro-rata basis. Therefore, the socialized transmission tariff design and the allocation of auction revenues based on load shares is internally consistent, supporting arguments of equity. However, given that PJM has zonal transmission tariffs, a pro-rata allocation approach of FTR auction revenues based simply on load shares may not be viewed as equitable by some LSEs. Moreover, eliminating the ARRs from PJM's design would harm some load that has historically preferred to self-schedule ARRs in the FTR auctions.

Another notable distinction in the rules for FTR auctions is that none of these other markets had an FTR forfeiture rule like that in PJM. CAISO has something similar, but in practice, it is far less constraining. MISO has had issues with market manipulation between the virtual and FTR auctions but has preferred more active market monitoring instead of implementation of an automated mitigation rule. This observation, coupled with stakeholder concerns raised during the FGDs, suggests that the current FTR forfeiture rule should be carefully re-evaluated.

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[14] There is an exception. Non-opt in Entities ("NOIEs") are pre-allocated some CRRs at a discount. NOIEs consist of municipally owned utilities, electric cooperatives , and River Authorities.

[15] LSEs in ERCOT can still purchase CRRs in the auction, but they are not provided (to most) LSEs for "free" as is the case with ARRs in PJM.

Task 4: Comparative analysis of FTR/ARR designs in other US markets uncovered several differences.

Based on LEI's understanding of the market circumstances, some differences would not be beneficial or relevant to PJM's construct:

- use of simple allocation rules (like pro rata to load) in combination with a single right system would reduce the flexibility and value that PJM load gets from ARRs, and would conflict with the zonal transmission rate design; and
- reduction of FTR paths may decrease the efficiency of the FTR auctions and undermine the value of the ARR property right and longer-term benefits to load from liquid forward markets.

Other differences could be enhancements for further consideration by PJM and its stakeholders:

- PJM should investigate the feasibility of introducing more granular ARR products (peak and off-peak and seasonal); and
- PJM should also revisit the FTR forfeiture rule based on the experiences of other ISOs/RTOs.

1.5 Recommendations for exploring changes to the current design (Task 5)

LEI recommends that PJM and its stakeholders focus on enhancing equity-related aspects of the current design of ARRs/FTRs while maintaining efficiency-related aspects of the existing mechanism. In terms of equity-related enhancements, PJM should first work with stakeholders to develop an objective definition of equity in relation to the relative size of congestion charges to be returned to each LSE. Although LEI recognizes that defining equity is a judgment-based criterion, and changes to distribution/allocation are likely to create winners and losers, it is possible to ground the investigation of equitable allocation schemes in first principles related to the existence of congestion charges (pattern of LMPs and size of load) and acknowledgment of the rationale for return of congestion charges (i.e., because load has already paid for transmission service through a separate tariff).

PJM should also undertake an audit exercise to track down and categorize who paid congestion charges that are not already easily associated with load (because of unknown location, contracts/self-scheduling, etc.). This information would help stakeholders examine whether alternative allocation schemes are aligned with the agreed-upon definition of equity.

Once the foundation tasks are complete, PJM should work with stakeholders to identify alternative allocation schemes for ARRs. In this regard, LEI proposes that PJM and stakeholders consider one of the following potential mechanisms for the initial designation of ARRs to LSEs:

- division of paths based on actual or expect network usage, which reflects recent energy market activity or contractual portfolios; or

- division of paths based on expected LMPs or value of congestion rents.

In addition, PJM and stakeholders will need to explore how to evolve the surplus congestion allocation rules. As a starting point, LEI proposes the following options be considered by PJM and stakeholders:

- the surplus remaining after ARRs and FTRs are fully funded could be allocated to load based on pro-rata transmission revenue requirement paid;

- if congestion charges should be returned to load because all congestion charges are overpayments by load and the purpose of FTR is to "refund" such overpayments, then PJM could develop a metric in measuring overpayment each LSE contributed; or,

- a simple load share ratio can be considered if the surplus congestion is determined to be devoid of locational differences among LSEs.

LEI also identified three other potential enhancements that would support improving outcomes relative to Purpose #1; these are listed in Figure 11. These enhancements would also work to increase the efficacy of the ARRs awarded to load and reduce the surplus congestion that would have to be allocated based on rules. In summary, the goal of considering alternative allocation methods and ARR enhancements should be threefold: (i) reduce the size of leftover network capacity and thereby reduce surplus congestion; (ii) equitably assign aggregate congestion payments collected by PJM to various LSEs; and (iii) better align ARR paths with actual needs (contractually) and actual system usage.

Figure 11. Alternative allocation methods - goals and solutions

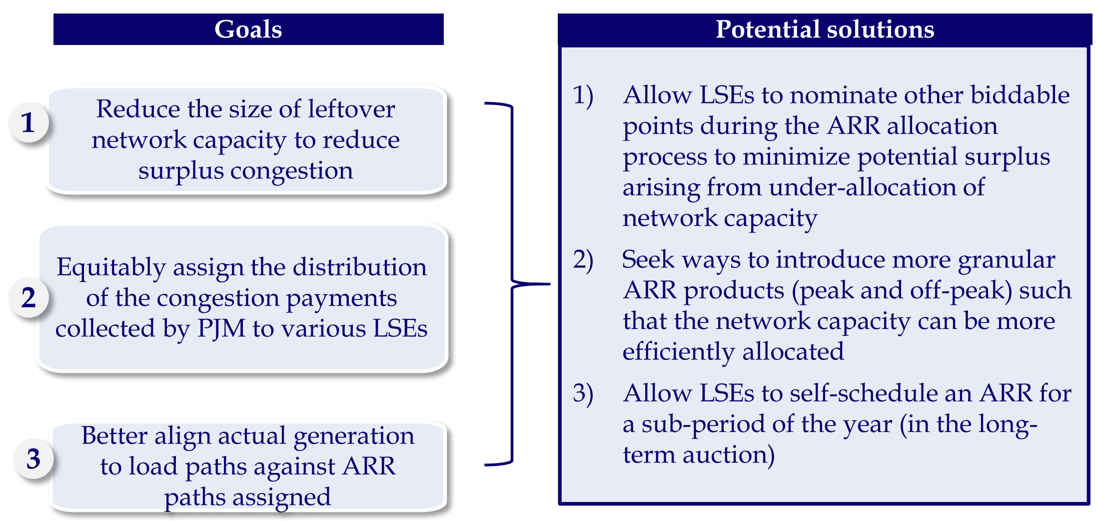


Figure 12 provides a summary of LEI's proposed enhancements to the current ARR/FTR design.

In terms of efficiency-related modifications, the current FTR auction design is reasonable and generally supportive of both purposes. LEI suggests retaining the current set of auctions and continuing to allow unrestricted market participation. Although LEI did not find any systematic evidence of excessive profiting by non-load (financial participants), PJM should continue to monitor competition and profitability trends over time in the FTR auctions. LEI also recommends that PJM adjust the clearing rules for FTR options to ensure that FTR options are not sold without a premium over the same FTR obligation path.

Finally, in terms of transparency and simplicity, several changes should be explored in order to enhance stakeholder satisfaction with the ARR/FTR outcomes and expand stakeholder understanding of the network model. These recommendations arise out of the concerns that LEI heard from various stakeholders during the FGDs. LEI suggests that PJM seek ways to provide more detailed documentation of changes made between releases of the network model. Based on what is done in other markets, stakeholders may find value from a network model manual that PJM would publish. Such a manual could contain descriptions of key procedures, definitions, and address software (compatibility) questions. Finally, LEI suggests that PJM consider retaining a transmission expert to independently review on a regular basis (e.g., every 3 or 5 years) the network model, to instill confidence in PJM's approach and assumptions that impact the network capacity that is allocated in the ARR process and FTR auctions.

Figure 12. Proposed enhancements to the current design

Equity

- Develop an objective definition of equity; establish a more detailed understanding of zonal patterns of congestion
- Expand biddable points and time of use periods for ARRs
- Add flexibility to self-scheduling rules
- Explore alternatives to historical path assignment of ARRs
- Explore alternative allocation approaches for distributing surplus congestion

Efficiency

- Maintain PJM's annual, monthly and long-term FTR auctions
- Continue to allow non-load participation and current set of biddable points
- Monitor competition and profitability trends over time
- Determine a minimum premium for options
- Evaluate changes to the current FTR forfeiture rule

Transparency and simplicity

- Issue a network model manual
- Provide detailed documentation of changes over time
- Periodically retain transmission expert to independently review the network model

1.6 Responses to the key questions

1) **What is the original intent of ARR and FTR? Was it to address a problem?** Yes. Originally, PJM Companies and FERC identified the need for FTRs to (1) return congestion payments in LMPs back to load and to (2) support hedging and integration of bilateral contracts with LMP spot markets and complement forward market activity. *(Section 3)*

2) **Are they fulfilling, in the best way possible, their initial purpose and/or addressing the identified problem?** The existing design is fulfilling Purpose #1 on an aggregate basis. But there may be equity issues between different LSEs. The path-based FTR product and the extensive trading opportunities presented by the various FTR auctions are providing price discovery for the forward market; bilateral transactions are frequently delivering to nodes, and new generation resources are taking advantage of financial hedges. Taken together, these observations suggest that the FTR auctions are also supporting longer term electricity market dynamics and fulfilling Purpose #2. *(Section 6)*

3) **If not, why not? If so, how is this measured and verified?** To confirm attainment of Purpose #1, LEI analyzed aggregate payout ("total offset") to load across PJM relative to the total congestion payments collected in LMPs. As part of the exercise, LEI also considered the initial allocation of ARRs and outcomes in the FTR auctions, and the decision of LSEs to hold onto ARRs versus self-schedule. LEI also analyzed the distribution of the payouts among load zones. For Purpose #2, LEI analyzed the predictive power of various FTR auctions. LEI also collected data on physical transactions, financing practices for new generation, and examined futures trading and hedging activities. *(Sections 5 and 6)*

4) **Is this purpose still required, and if it is addressing a problem, are there alternative ways to eliminate the problem entirely?** The original purposes for having FTRs are still relevant today. LEI reviewed the ARR/FTR (or equivalent construct) in other US markets. LEI determined that the alternative approaches (such as direct allocation of FTR revenues or limitations on biddable points in FTRs) would not be preferable in the context of the PJM wholesale market. Therefore, a comprehensive alternative does not currently exist; however, the case study analysis suggested some areas for further consideration. For example, LEI observed MISO had more granular ARRs classes, which could improve the amount of feasible ARRs that could be allocated. LEI also observed that PJM was unique in application of its current FTR forfeiture rule. In combination with the concerns raised by stakeholders, this rule may need to be reviewed. *(Section 6 and 7)*

5) **Are there additional purposes and/or sources of value to the market that ARRs and FTRs are, or should be, fulfilling or delivering? If so, what are these purposes, how do they optimize value to load and other market participants; and how is this value optimization measured and verified?** Both purposes identified by LEI are important but not always complementary. Purpose #1 yields short term benefits to load while Purpose #2 provides longer-term benefits. Some portion of the value to load in the short term may need to be sacrificed to support the realization of the benefits in the longer term. The best way to examine whether this is yielding a net positive outcome is to consider the amount of short-term benefit that is foregone (e.g., FTR profits going to financial parties) versus the amount of long run benefits (e.g., liquid forward markets which help drive down the long run marginal costs of energy and transactions costs for hedging). *(Section 6)*

6) **What other mechanisms, either inside or outside the RTO, can provide alternative ways to achieve some of these purposes? If such mechanisms exist, can they work alongside each other or as variations to current mechanisms to optimize value to load and other market participants?** An alternative way to achieve Purpose #1 has been proposed by the IMM. It would be a complete overhaul of the current system and therefore could cause some disruption with current bilateral trading and hedging activities. In general, the IMM's proposal is novel and untested. LEI has concerns that it may have shortcomings related to Purpose #2, given that the IMM designed it exclusively for Purpose #1. A more detailed specification of the IMM's proposal is required before a decision can be made on the overall merits of the IMM's proposal. *(Section 6)*

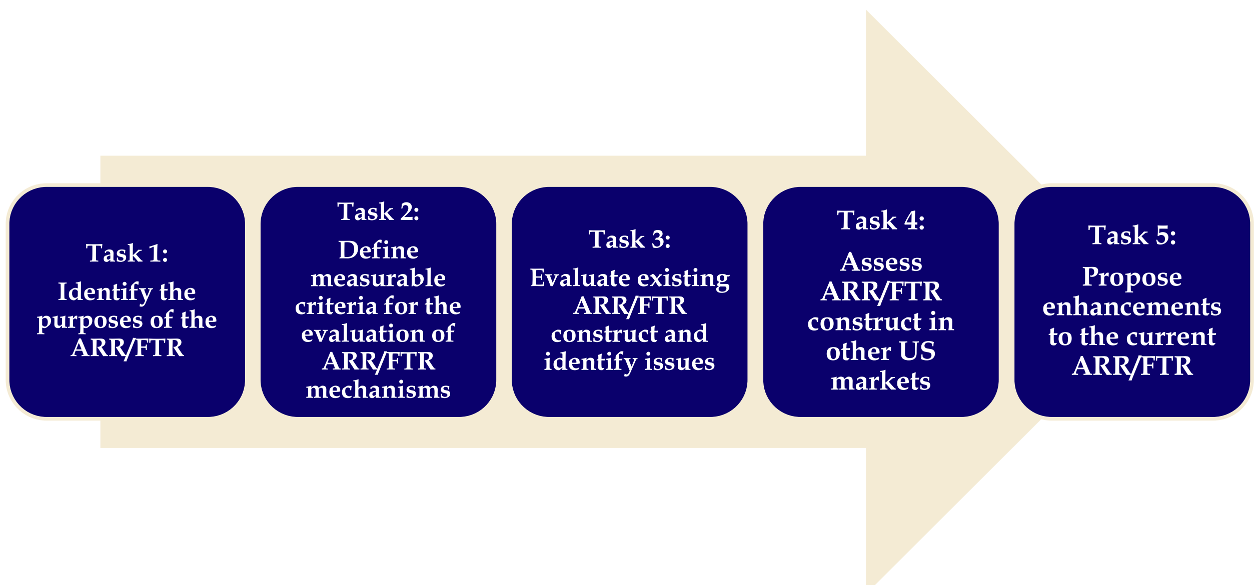
7) **Are there changes in the market design, execution, etc. that would improve delivery of these instruments' purpose?** Based on the findings compiled in this report, LEI concludes that the dual system of property rights remains valid and valuable to load, and that a path-based construct for ARRs and FTRs is consistent with bilateral arrangements and hedging. LEI has recommended several enhancements to the ARR mechanism (and allocation process) to improve the equity considerations under Purpose #1. LEI does not believe major changes are necessary to the FTR mechanism because the auctions appear to be functioning efficiently and supporting both Purpose #1 and #2. LEI has proposed several modest changes to the FTR construct which include changing the auction clearing rules to avoid selling underpriced FTR options, monitoring competition and profitability trends over time, and revisiting the FTR forfeiture rule. *(Section 8)*

2 Overview of the engagement

LEI was engaged by the PJM Interconnection ("PJM") in August 2020 to provide an independent, holistic assessment of PJM's FTR market and ARR mechanism. As discussed below, LEI's holistic approach includes both quantitative and qualitative approaches, which include reviewing the evolution of PJM's ARR/FTR market thoroughly, defining measurable criteria to evaluate the different aspects of the ARR/FTR markets, performing analyses, looking at other ISOs/RTOs' ARR/FTR construct, and engaging with the stakeholders, including the independent market monitor ("IMM") and PJM staff.

The overarching question to be answered in this engagement is whether the existing ARR/FTR market design is set up to ensure that load receives the optimum value of the transmission system. PJM also provided a list of questions that needed to be addressed by this study, which is listed in Figure 1 on page 1. To address these questions, LEI utilized a methodological approach consisting of five tasks, as shown in Figure 13.

Figure 13. Key questions to be addressed, LEI's five tasks and approach



As part of Task 1, LEI undertook a detailed review of PJM's ARR/FTR mechanism, including an analysis of the original proposal filed by the PJM Companies in 1996 with FERC and the initial FERC decision(s) approving the LMP design and FTR construct. Task 1, therefore, addressed questions #1 and #2 in the Key Questions. As part of LEI's review, LEI also analyzed materials submitted and discussed at the PJM ARR/FTR Task Force meetings, including the Whitepaper published by PJM in April 2020 entitled "Financial Transmission Rights Market Review."[16] LEI

[16] LEI will refer to this report as the "PJM ARR/FTR White Paper."

also reviewed detailed sections related to congestion and FTRs in the State of the Market ("SOM") reports prepared by the IMM. Finally, LEI looked at various supporting documents, including PJM Manual 6: Financial Transmission Rights, prior PJM filings and FERC Orders related to ARR and FTR constructs, academic journals and publications, and published materials by PJM, IMM, and stakeholders. Appendix G (Section 15) of this report provides a list of the documents that LEI reviewed and relied on. The findings of Task 1 are summarized in Section 3 of this report.

Under Task 2, LEI selected criteria to assess whether the current FTR market design's fundamental objectives are being met. The selected criteria are described in Section 5. Task 2 helps address question #3 in the Key Questions.

As part of the framework, LEI also identified data gathering opportunities and then pursued those as part of Task 3. One opportunity included a quantitative review of the historical ARR allocation and FTR auction-related data vis-à-vis day-ahead energy market outcomes. Another venue for getting inputs about the ARR/FTR market design involved interviewing stakeholders, including LSEs participating in the ARR allocation process and FTR markets, traders active in FTR auctions, end-use customer representatives, state regulatory agencies, and PJM staff and the IMM. The third source of information to support the assessment came through case study analysis of other US power markets with nodal (LMP) energy spot market design (this was Task 4, essentially). Task 3 findings are summarized in Section 6 of this report, while key observations from Task 4 are found in Section 7. Tasks 3 and 4, in combination, address questions #2 to #6 in the Key Questions.

Based on (1) LEI's qualitative and quantitative examination of the current design, (2) LEI's comparative analysis of PJM's market design with that of CAISO, ERCOT, and MISO, and (3) feedback received from stakeholders, LEI identified potential enhancements to PJM's ARRs/FTRs in Task 5 (Section 8). In so doing, LEI addresses question #7 of the Key Questions.

3 Identifying the purpose of the ARR/FTR mechanisms (Task 1)

Key takeaways

- **Based on LEI's independent analysis, FTRs (and ARRs) serve two purposes: (i) to return congestion charges collected in LMPs to load and (ii) to support bilateral contracting/forward markets and improve the long run signal for investment.**
- Although LMPs ensure efficient use of the transmission system, and as a result, efficient production, and consumption in real-time, the LMP design also causes overpayment by load when the transmission system is congested. As a result, PJM collects more funds from load than it pays out to generators, resulting in congestion charges. FTRs were introduced as a mechanism to give load the right to these congestion charges, which is the first purpose. The creation of ARRs in 2003 also reflected the same purpose, as it gave load priority in the transmission system and greater flexibility around how and when load seeks to recapture the overpayment in LMPs.
- In implementing LMP-based spot markets, PJM Companies and FERC acknowledged that bilateral contracting would continue. Indeed, bilateral contracting and forward markets are an instrumental component of the overall wholesale market design, as they provide the pathway for risk re-allocation (hedging), signal the need for investment, and support various commercial activities to ensure lowest possible costs of supply in the long-term. FTRs provide an important link between the LMP-based spot markets and forward markets through the FTR auctions. Therefore, the second purpose of the FTRs is to support bilateral contracting/forward markets to assure the efficient use of the transmission system and lowest possible costs of energy in the long run.

Identifying the purposes of the FTRs is crucial in determining whether the ARR/FTR construct is working as intended. Currently, there are different views on the purposes of FTRs. For instance, the IMM believes that the ARR/FTR construct has only one purpose: to return *exactly* 100% of the congestion charges collected in LMPs back to load.[17] Although FERC recognized that FTRs would facilitate the return of congestion charges to load, FERC never stated that load should receive *exactly* 100% of congestion charges collected n LMPs. Indeed, FERC described the conceptual basis for FTRs more broadly than simply the return of congestion charges in the original decisions, referring to the concept of hedging and discussing the PJM Companies' arguments regarding the need to accommodate bilateral contracts.[18] More recently, FERC clarified its understanding, noting that that FTRs were "designed to serve as the financial equivalent of firm

[17] Monitoring Analytics. "Quarterly State of the Market Report for PJM. 2020." November 12, 2020, p. 684.

[18] Federal Energy Regulatory Commission. "Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing Establish of an ISO and Disposition of Control over Jurisdictional Facilities and Denying Rehearing." November 25, 1997. (81 FERC ¶61,257)., p. 70.

transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion-hedging function."[19]

3.1 Introduction of LMP system necessitates FTRs

The need for FTRs arose due to the introduction of LMP-based spot markets and open access to the transmission system.[20] Market designers selected the LMP design for spot markets because it ensured efficient use of the transmission system by pricing the locational differences that were a function of network constraints (see textbox on the next page). By internalizing congestion on the system, LMPs also led to efficient production and consumption decisions in the spot market. However, market designers and FERC recognized that LMP markets would not replace existing commercial arrangements. Bilateral trading and forward markets would continue, and the LMP system would need to be able to work collaboratively with these other commercial arrangements.[21,22]

What are FTRs and ARRs?

FTRs are financial instruments that allow the holder to get paid for transmission congestion charges that occur when the transmission grid is congested in the day-ahead energy market. PJM uses the point-to-point construct where the source (point of receipt) and sink (point of delivery) and the quantity (MW) is defined.

ARRs are another type of transmission right in PJM. Like FTRs, ARRs are defined on path-basis by the sink and source points. They are allocated annually to load serving entities in PJM (and other firm transmission customers who may be eligible for ARRs). ARRs entitle the holder of the ARR to receive a payment (known as "ARR Offset") based on the quantity of ARRs held (on a specific path) multiplied by the nodal Congestion cost component of the LMP ("CLMPs") that are an outcome of the annual FTR auction.

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[19] FERC. 158 FERC ¶ 61,093. January 31, 2017.

[20] Prior to the LMP system, the PJM market was based on cost of service rates, where the delivery of low-cost generation was based on utility-owned local generation and contracts with remote generation. To ensure the delivery of the energy from contracted remote generation, the utility paid for physical rights associated with the transmission system for the delivery of energy.

[21] FERC. "Order Conditionally Accepting Open-Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control over Jurisdictional Facilities, and Denying Rehearings." November 25, 1997, p. 61 (81 F.E.R.C. P61,257).

[22] PJM, "Brief of Supporting Companies." Compliance of the Pennsylvania-New Jersey-Maryland Interconnection with Order No. 888. Docket No. OA-97-261-000. December 31, 1996. pp. 86-87.

Under the LMP pricing system, the marginal cost of congestion is embedded in LMPs, and therefore LMPs would vary by location when the transmission system is congested. Moreover, as a result of the uniform pricing concept, collected LMP payments from all load would exceed the cumulative LMP payments to generators when the transmission system is congested.[23,24] This was

How are LMPs calculated?

LMPs reflects the price of electricity at a specific location of the transmission system. This is because energy prices vary due to its cost of generation and transmission, depending on their geographic regions. Additionally, LMPs account for the marginal cost of energy at that point in time and the marginal cost of congestion on the network to deliver the energy to that location (as well as marginal transmission losses).

LMPs are calculated based on a set of shadow prices, which estimate the marginal economic value of relaxing a constraint by one unit of additional capacity (MW). The shadow prices are a byproduct of the security constrained dispatch model, which aims to minimize the system energy production cost combined with the constraints that result from the power balance, and transmission and dispatch limitations. LMPs can be decomposed into three components:

Locational marginal price = System marginal price + Congestion component + Marginal loss component

System marginal price:
- Energy component of all LMPs; the price for electric energy
- Same price for every bus

Congestion component:
- Represents the marginal cost of congestion at a given node
- Varies by location

Marginal loss component:
- Reflects price of marginal losses
- Varies by location

Under the LMP system, load could overpay for the cost of supply, because of network constraints and the uniform pricing application of LMPs. During periods of congestion (and leaving out for purposes of simplification the marginal loss component), LMPs will vary by location due to the marginal cost of congestion (the transmission congestion cost). All load in the constrained zone would pay a higher LMP, even if part of the load was served with cheaper resources that were outside the constrained zone. So, when PJM makes payment to the generation, if will have leftover amounts. This is known as the congestion charge. Appendix A (Section 9) provides a numerical example of how congestion charges arise in a LMP system.

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[23] Hogan, William. "Report on PJM Market Structure and Pricing Rules. December 31, 1996. Docket OA97-261-000. pp. 50-51.

[24] Please refer to Appendix E (Section13) for numerical example.

deemed unfair given that load had already paid for transmission service through a separate regulated charge. [25] Therefore, one purpose of the FTR construct was to return the overpayments.

3.2 Supporting hedging and bilateral contracting

In the original filings, the PJM Companies and their experts showed that the congestion component of LMPs would be difficult to predict and would be volatile.[26] This uncertainty created friction with bilateral contract arrangements,[27] because it undermined the ability of LSEs to guarantee a set price to their load customers. Even if an LSE locked in the cost of energy through a power purchase agreement ("PPA"), there was still exposure to the marginal cost of congestion in the spot market. FTRs could create a "perfect hedge" for the volatile congestion component in LMPs.

PJM proposed (and FERC approved in November 1997) that all firm transmission customers be awarded FTRs for the paths defining their specific receipt and delivery point reservations.[28,29] A path-based construct for FTRs was intentionally selected to align bilateral and self-supply arrangements with the LMP-based market. More specifically, bilateral transactions and self-supply can be accommodated in the LMP settlement process by virtue of locational specification: a market participant simply needs to specify the location of the receipt point (location of generation source) and withdrawal point (location of load). The point-to-point definition of FTRs is consistent with this arrangement and allows market participants to hedge their exposure to locational price differences between the location of their supply sources and load obligations. Therefore, the second purpose of FTRs is to support bilateral contracting and hedging, or more broadly linking the spot energy markets and forward markets.

In the 2003 FERC Order (that accepted the introduction of annual FTR auctions and ARR allocations) and Order No. 681 of 2006, FERC also emphasized the significance of FTRs in

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[25] 81 FERC P61,257, p. 34.

[26] 81 FERC P61,257, p. 32 .

[27] 81 F.E.R.C. P61,257, p. 32; FERC. Long-Term Firm Transmission Rights in Organized Electricity Markets. 114 FERC ¶ 61,097. February 2, 2006. p. 17.

[28] 81 FERC ¶ 61,257, p. 9.

[29] Market participants with firm reservation are protected from congestion charges if they schedule energy consistent with the points of receipt and delivery specified for their reservations. This is what FERC and other parties referred to when using the term "perfect hedge."

facilitating hedging congestion price risk over a longer period of time, rather than for a term of only one year or less.[30]

> **PJM on long term benefits associated with transmission rights**
>
> *"Long term transmission rights have the potential to provide several market benefits:*
>
> 1) *Long term rights could provide a fixed hedge against changes in congestion over an extended time period, thereby* ***mitigating a major risk associated with LMP volatility*** *over the applicable period.*
> 2) *The ability to hedge congestion over a multi-year period could then* ***support the development of a longer-term energy product*** *due to the ability to mitigate congestion risk over the term of the right.*
> 3) *The development of longer-term energy products could, in turn,* ***facilitate additional market benefits by creating forward price signals that could support the development of more liquid forward markets.***
> 4) *Given that investment in energy infrastructure is capital intensive and involves long-lived assets, a liquid forward market is an essential element in establishing an environment to support infrastructure investment, financing, and risk management.*
> 5) *Long term transmission rights would also create additional FTR products, thereby increasing the ability of participants to* ***effectively manage market positions*** *consistent with varying levels of risk tolerance.*
> 6) *Finally, long term transmission rights would* ***provide a longer-term price signal for transmission investment by guaranteeing a fixed revenue stream for the term of the right****."*
>
> *- PJM (Filing to FERC - Docket No. AD05-7-000, June 2005); Emphasis by LEI*

The role of FTRs in supporting forward markets became more explicit with FERC's decisions after the passage of the Energy Policy Act of 2005 ("EPAct 2005"). This legislation added section 217(b)(4) to the Federal Power Act. It explicitly provided load with *long term* firm transmission rights (or equivalent tradable financial rights) for purposes of hedging congestion charges associated with the delivery of power from a long-term power bilateral supply arrangement executed in advance of the spot market. PJM's comments on the FERC Staff Discussion Paper on LTTR Assessment identified a list of longer-term benefits associated with the ARR/FTR mechanism that provided long-term transmission rights (see textbox above). FERC's Order No. 681, which set the new guidelines for US RTOs/ISOs, ensured that load had LTTRs. This also aligned with PJM's comments. Specifically, Order No. 681 affirmed the importance of the benefits identified by PJM.[31] In summary, PJM's comments and FERC's Order No. 681 highlighted the fact that the ARR/FTR construct can and should support liquid and efficient forward markets

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30 FERC. 102 FERC P61,276. Washington DC, 2003., p. 2; and Federal Energy Resource Commission. Order No. 681: Long-Term Firm Transmission Rights in Organized Electricity Markets. July 20, 2006., p. 8.

31 PJM. PJM Interconnection LLC. Comments of PJM Interconnection on the FERC Staff Discussion Paper on Long Term Transmission Rights Assessment, Filing: AD05-7-000, Washington, DC, June 27, 2005.

(Purpose #2). As noted by PJM, load would ultimately benefit from investments – in transmission and generation infrastructure – that the forward market would facilitate.

Although the mechanisms for engaging in the sale and purchase of FTRs have evolved since its inception, the initial purposes for having FTRs remain valid today as load continues to pay for transmission, and market design continues to depend on an efficient spot market and a functioning forward market.

4 Overview of PJM's ARR/FTR market evolution

Key takeaways

- Since 1998, PJM has evolved its FTR (and ARR) mechanisms to improve on both Purposes #1 and #2 by giving load more opportunities to have the congestion charges returned to it and advancing the functionality of FTR trading and expanding hedging opportunities.
- Most changes over time were in response to identified challenges in the functionality of the ARR/FTR construct, as well as practical considerations for dealing with changing system conditions.

To evaluate the current design, it is important to understand the various changes to the ARR/FTR mechanism over time and how the changes are related to the underlying purposes. Over the past 20 years, numerous modifications have been introduced to the ARR and FTR institutions at PJM to reinforce both of the original purposes. For example, the ARR allocation process has been transformed in several ways including the introduction of stage 1A allocation, addition of residual ARRs, and practical updates to eligible ARR paths (because of retired generation sources and new sources). PJM has also made changes to the FTR product and auction design. For example, over the years, PJM increased the number of FTR products offered and added incremental opportunities to buy and sell FTRs.

4.1 Key changes in the ARR construct

In 2003, PJM introduced ARRs, a new class of entitlements distributed to LSEs (and other firm transmission service customers)[32] in lieu of direct allocation of FTRs to load.[33] Like FTRs, ARRs are a path-based property right. LSEs can hold onto ARRs or convert them into FTRs. In this way, the ARRs maintained the "priority" of load to the transmission system capacity but also added some flexibility for LSEs around when/how they would monetize the value of their property right. More specifically, LSEs can lock in the amount of congestion payments a year in advance

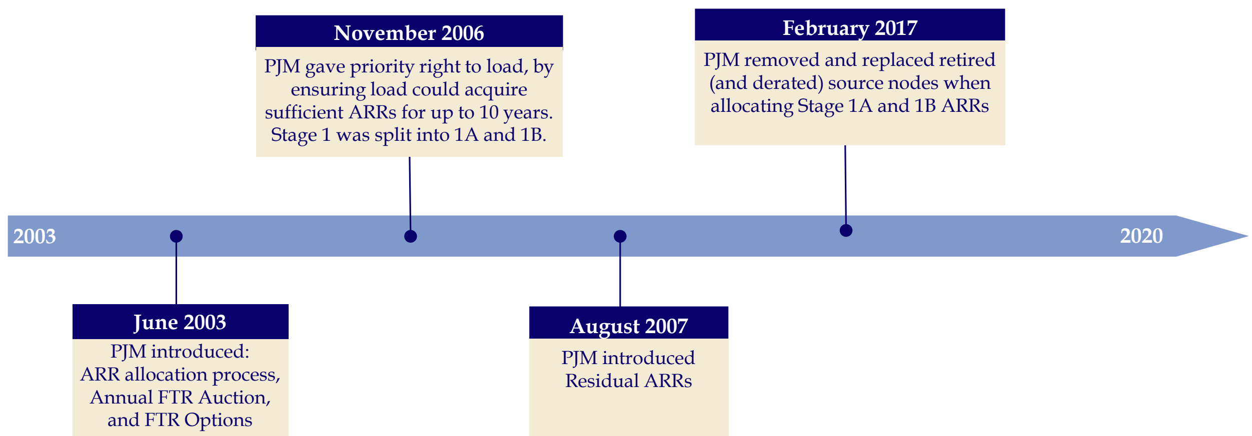
[32] PJM is not the only market with ARRs. New England added ARRs in 2003, Midcontinent Independent Transmission System Operator added ARRs in 2007, and Southwest Power Pool ("SPP") added ARRs in 2012. *See*. New England ISO website. < https://www.iso-ne.com/participate/support/faq/financial-transmission-rights#a>, MISO Filling in Docket No. ER07-418-000, January 29, 2007., SPP Filling in Docket No. ER12-1179-000, February 29, 2012.

[33] An incremental FTR was created alongside FTR for the purpose of incentivizing customers and generators to expand on the grid and ensuring that they receive a form of FTRs even after FTRs have been allocated during the planning year. The Incremental FTR was crucial as it supported Purpose #2, by signaling for efficient investment to the transmission system in the long run. When ARRs were introduced in 2003, Incremental FTRs were renamed and reconfigured as Incremental ARRs (IARRs). The function of IARRs is the same as Incremental FTRs. Section 6.4 discusses IARRs and the total number of requested IARRs in the past five years.

of the spot market. In summary, the introduction of ARRs provided an alternative mechanism for load to hedge congestion price risk in LMPs.[34]

Since 2003, there have been several changes to ARRs, as shown in Figure 14 below. These changes aimed to modify the allocation processes of ARRs and allow for new generation or transmission capability to be included in the ARR market. These changes aligned with Purpose #1 and #2, as it allowed load more flexibility on its rights to congestion charges but also enhanced investment in transmission. Appendix B (Section 10) provides a more detailed description of the major events in PJM's ARR/FTR market.

Figure 14. Evolution of ARRs and its allocation process



Source: FERC Orders

4.1.1 Long-Term Transmission Rights and the revision to the ARR Stage 1 Allocation

In 2005, the Federal Power Act was amended to grant FERC the power to require public utility transmission organizations to provide long-term transmission rights to LSEs.[35] FERC provided a set of guidelines for RTOs and ISOs so that they could guarantee long-term transmission rights to load (described in the blue textbox below). In response to the FERC guidance, PJM revised the ARR construct to comply with the FERC's ten-year transmission right requirement. Specifically, PJM gave priority rights to load to network capacity by ensuring that all load could acquire sufficient ARRs for up to 10 years.[36] To facilitate this guarantee, Stage 1 was split into 1A and 1B. Stage 1A would allow PJM to determine if the ten-year ARRs would be feasible alongside all

[34] Federal Energy Regulatory Commission. 102 FERC P61,276. Washington DC, 2003. p. 7.

[35] FERC. 116 F.E.R.C. P61,077. Washington D.C., 2006.

[36] PJM. PJM Interconnection LLC. Filing: ER06-1218-000., Washington D.C., 2006.

other Stage 1A ARRs for the subsequent ten years.[37] The addition of a long-term ARR and revision of the Stage 1 allocation process is consistent with Purpose #1 of FTRs. It provides load the opportunity to access a volume (baseload) equivalent of the auction revenues. Additionally, this change is also consistent with Purpose #2 (i.e., motivating transmission investment, if system congestion resulted in a situation where load was not receiving its guaranteed level of network capacity in the ARR allocation process, as described in the textbox below). When a requested Stage 1A ARR does not pass the Simultaneous Feasibility Test ("SFT"), PJM will work with transmission owners and entities to build and upgrade transmission capability to ensure that the requested Stage 1A ARR would be feasible.[38]

"The LTTR proposal creates long-term transmission rights based on a priority ten-year ARR allocation for Zonal Base Load that ensures longer term certainty with the flexibility to opt-out of the ten-year rights on an annual basis to accommodate changes in market conditions. PJM states that the proposal creates a link between the long-term transmission planning process and the ARR allocation process to ensure the transmission system is upgraded to maintain the feasibility of stage 1A ARRs for Zonal Base Load plus the projected ten-year growth of base load. PJM adds that the proposal also provides a mechanism for identifying upgrades and the associated costs needed to support requests for thirty-year incremental ARRs, i.e., new ARRs that result from system upgrades."

- FERC Order (117 FERC ¶ 61,220) (November 22, 2006)

4.1.2 Residual ARRs

On August 13, 2007, FERC approved PJM's request to add a Residual ARR product. Residual ARRs are directly allocated to load when new transmission capacity developed during the Planning Period becomes available (as described in the textbox to the right).[39,40] However, it should be noted that Residual ARRs cannot be converted to FTRs currently, unlike regular ARRs, because they are allocated after the annual FTR auction. The purpose of creating the Residual

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[37] Ibid.

[38] As stated in Appendix B (Section 10), in 2012, PJM found constraints in its network model on the amount of Stage 1A ARRs it could award to LSEs in the Commonwealth Edison Company zone. Therefore, PJM proposed a transmission upgrade as part of the RTEP process to remedy this ARR allocation issue (e.g., the Grand Prairie Gateway project, which was completed in 2017).

[39] PJM. PJM Interconnection LLC. Filing: ER07-1053-000., Washington D.C., 2007.

[40] Once Residual ARRs have been allocated, they would be available as regular ARRs in the following annual ARR allocation process since the new transmission system would be included in the power flow model. *See* PJM Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM, 2007." March 8, 2008.

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ARR was to remedy the ARR pathways that were prorated during Stage 1 of the annual allocation process.[41] ARRs are prorated when requested ARRs do not pass SFT.[42]

All ARRs requested for the annual allocation are subjected to the SFT using PJM's network model. The SFT ensures that there will be adequate revenue funding for ARRs and FTRs.[43] And frequently, not all requested ARRs are approved as a result of SFT, as the requested ARRs may be greater than the actual transmission capacity, therefore making the requested ARR (quantity and/or path) infeasible. Furthermore, potential transmission outages may also cause requested ARRs to not pass the SFT. However, even if the requested ARRs do not pass the SFT, PJM will continuously monitor conditions and seek ways to re-adjust the network during the planning period (e.g., work with transmission owners and entities) to ensure that Stage 1B would be fully feasible.[44] As such, LSEs may receive a prorated amount of the ARR requests in the annual allocation. The addition of Residual ARRs is consistent and enhances the original purpose of FTRs, which is to return congestion charges to load.[45]

"[Residual ARRs] can result from increases in physical transmission capacity, or by a change in any other system factor not considered in the simultaneously feasible model for an annual ARR allocation, and, if modeled would have increased the amount of ARRs allocated. The proposed rules create a new transmission right, Residual ARRs, for stage 1 prorated pathways, and establish allocation for such rights. The rights are associated with transmission capacity created during a Planning Period, after the annual ARR allocation, and, therefore, not accounted for in the annual allocation ("Intra-Planning Period Capacity")."

- PJM filing to Docket No. ER07-1053-000 (June 19, 2007)

4.1.3 Reflecting the retired generation in the allocation model

On January 31, 2017, FERC accepted PJM's proposal to remove and replace retired (and derated) source nodes when allocating Stage 1A and 1B ARRs.[46] Specifically, PJM replaced source points

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[41] Ibid.

[42] SFT is further discussed in Appendix C (Section 11).

[43] PJM Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM, 2007." March 8, 2008.

[44] A method and example to readjust the network during the planning period, with the collaboration of transmission owners and entities, is to build or upgrade transmission capability.

[45] According to the State of the Market Report, 2019, PJM allocated a total of 26,262.6 MW of residual ARRs, down from 31,554.6 MW in 2018. There was an ARR target allocation of $11.7 million for 2019, and $15.3 million for 2018, respectively, associated with these residual ARRs.

[46] FERC. 156 F.E.R.C. P61,180. Washington D.C., 2016.

associated with retired generators or generators that have reduced their installed capacity with an equivalent number of MWs for operating generators, defined as Qualified Replacement Resources ("QRR").[47] QRRs are identified based on the following criteria: a generation resource that has a determined installed capacity value for the delivery year and is not presently recognized as an ARR historical resource, pass an SFT, and to maximize the economic value of ARRs.[48] In addition, the QRRs should not consume greater than the total amount of transmission capability set in the current ARR allocation or future Stage 1A allocation.[49]

The replacement of retired (and derated) source nodes is essential, as the use of retired generation sources could lead to inaccuracy when determining the feasibility of Stage 1 ARRs. This disconnect between the network modeling (and the SFTs) and actual usage presents a problem, as it does not allow (i) proper investment signals since actual transmission may not be congested as the retired (and derated) source nodes are not in use; and (ii) ARR requests may be rejected due to the inaccurate modeling (as described in the textbox below).

> *"PJM asserts that it is appropriate to replace megawatts that are no longer considered to be capacity because such megawatts have not been studied for deliverability and thus do not reflect actual system usage […] by calculating the megawatt value of the resources that require replacement, PJM can ensure that each zone's Stage 1 capacity will be capped at total historical value, so as to: (i) recognize and preserve pre-FTR market transmission investments incurred by a load serving entity to deliver pre-FTR market total historical capacity value to serve its zonal demands; and (ii) ensure that PJM will allocate Stage 1 ARRs with a sufficient degree of pre-FTR granularity."*
>
> - FERC Order (158 FERC ¶ 61,093) (January 31, 2017)

4.2 Key changes in the FTR market

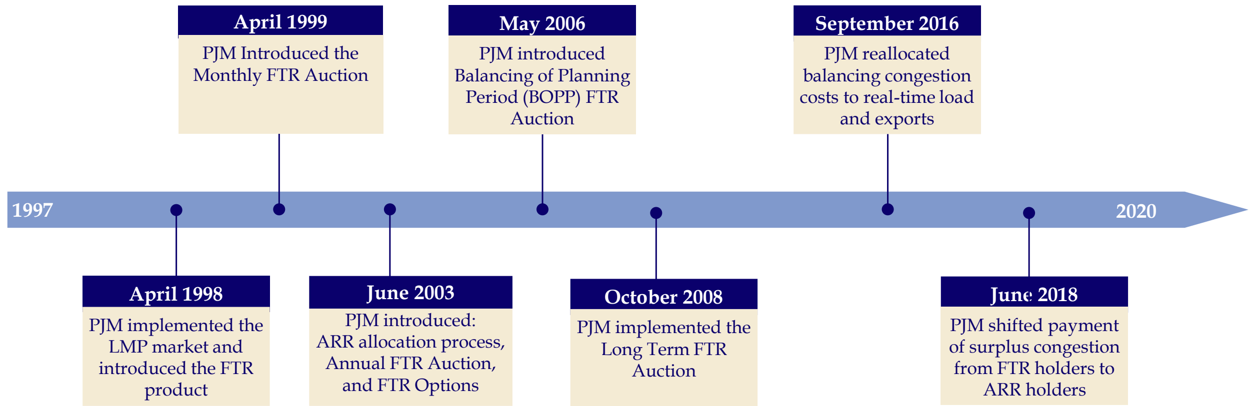
Various developments have occurred in the FTR market since 1998. The major changes include the addition of more FTR paths, an increase in the frequency of FTR auctions, and modifications in how FTRs are settled. All these changes aspired to improve the FTR auctions' efficiency, which positively impacted the achievement of both purposes. In particular, the changes that led to more efficient and frequent FTR auctions improved the payout to load (higher values to LSEs that hold ARRs, and more opportunity for hedging) as well as enhanced the price discovery for forward markets. These changes are reflected in Figure 15 below.

[47] FERC. 158 F.E.R.C. P61,093. Washington D.C., 2017.

[48] FERC. 158 F.E.R.C. P61,093. Washington D.C., 2017. p. 34.

[49] Ibid.

Figure 15. Evolution of FTR auctions and products



Source: FERC Orders

4.2.1 Addition of more FTR paths and monthly FTR auction

The first important change to the original FTR mechanism occurred on April 13, 1999, when PJM introduced a centralized monthly FTR auction. The purpose of the auction was to allow market participants (even non-LSEs) the opportunity to acquire residual FTRs that had not been allocated to LSEs (as described in the textbox to the right).[50] This provided another avenue for network customers (load) to obtain any FTRs they wanted, and that could not be awarded in the annual allocation process. LSEs could also sell the FTRs they were allocated. In summary, the monthly auction provided an easy way for LSEs to reconfigure their portfolio of FTRs.[51] This change recognized the theoretical importance of trading of property rights.[52]

> *"The monthly [FTR] auctions have allowed market participants (1) to submit bids to purchase residual capacity, (2) to submit offers to sell existing FTRs, (3) maximize the efficiency of FTR trading by providing an automatic reconfiguration of FTRs."*
>
> \- PJM filing to Docket No. ER03-406-000 (January 10, 2003)

50 FERC. 81 F.E.R.C. P61,257. Washington D.C., 2001.

51 PJM. PJM Interconnection LLC. Filing:ER03-406-000. January 10, 2003. p. 3.

52 According to the Coase Theorem, the trading of property rights (with minimal transaction costs) can ensure an efficient equilibrium, regardless of the initial allocation of property rights. Transaction costs and barriers to trading can obstruct efficient outcomes. *See* Robson, Alex. S. Skaperdas. "Costly enforcement of property rights and the Coase Theorem." Economic Theory, July 2008, Vol. 36, No. 1. pp. 109-128.

4.2.2 Addition of annual FTR auction and FTR options

> *"The new annual FTR auction process (1) will create a more liquid and deeper market for FTRs, (2) will allocate more efficient scarce FTRs, (3) will give customers more flexible options for hedging their risk, and (4) will create a more active secondary market for FTRs."*
>
> \- PJM filing to Docket No. ER03-406-000 (January 10, 2003)

In 2003, FERC accepted PJM's proposed tariff changes, which created the annual ARR allocation process (as discussed in Section 4.1), annual FTR auction, and an FTR option product. Since then, LSEs have no longer been directly allocated FTRs. Instead, LSEs were allocated ARRs, and the annual FTR auction allowed them to convert those ARR obligations into FTR obligations. The annual FTR auction also allowed participants to buy and sell FTRs to fulfill their congestion hedging needs (as described in the textbox to the right).

At the same time, PJM introduced FTR options, making it easier for a market participant to buy an insurance product against congestion risk on a certain path. Note that options paths are only available for select source and sink nodes based on PJM's network model.[53]

4.2.3 Monthly balance of planning period FTR auction

On November 2, 2005, PJM proposed to create two intermediate-term FTR products: the "Balance of Planning Period FTR" and the "Planning Period Quarter FTR."[54] This change was in response to market participants' request for FTRs that cover a period longer than one month but shorter than one year (as described in the textbox below).[55]

The Balance of Planning Period FTR covered a multi-month period that reflected the remaining months within a planning period. Market Participants are able to bid or offer monthly FTRs for any of the next three months remaining in the planning period.[56] These auctions start at the beginning of each month (after the monthly FTR auction) and run through May 31st each year.[57] The Planning Period Quarter FTR covered four discrete, three-month periods that remain within the planning period.[58] These products were available during the monthly FTR auctions, in addition to the single-month FTR products.

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53 FTR options can only be offered to the extent there is residual capability.

54 PJM. PJM Interconnection LLC. Filing: ER06-150-000., Washington D.C., 2005. p. 2.

55 Ibid.

56 PJM Market Monitoring Unit. Monitoring Analytics, LLC. State of the Market Report for PJM, 2007. March 8, 2008.

57 PJM. PJM Interconnection LLC. Filing: ER06-150-000., Washington D.C., 2005. p. 2.

58 It is important to note that since the 2018/2019 planning period, the Planning Period Quarter FTR is no longer used.

"PJM's monthly FTR auctions currently offer FTRs with a term of one month covering the following calendar month, and PJM's annual auction offer FTRs with a term of one year corresponding with the PJM Planning Period. Some Market Participants have indicated that an FTR product covering a period of time greater than one month but less than one year would better serve their business planning needs. In response, PJM has developed new FTR products having terms falling between those of the FTR products currently available."

- PJM filing to Docket No. ER06-150-000 (November 2, 2005)

4.2.4 Long Term FTR auctions

In 2008, PJM introduced the Long Term FTR ("LT FTR") Auctions to provide a platform for market participants to trade FTRs products that are (i) longer than one planning period, and (ii) single planning period FTRs that could be used in subsequent planning periods.[59] The LT FTR Auctions afforded market participants (including LSEs) the ability to acquire new 3-year forward FTR products and lock in their congestion cost for a future period (as discussed in the textbox below). Participants could request any source and sink points for 24-hour, on-peak, or off-peak blocks, as long as the requested FTR passed the SFT.[60]

LT FTR auction provides for the sale of FTR obligations only because FTR options would be difficult to model and account for in the long-term. Additionally, the inclusion of FTR options would significantly increase the number of scenarios that would have to be simulated in the SFT to ensure revenue adequacy.[61]

"The long-term FTR will enhance the total package of FTR products offered in PJM's Market in several ways. First, it will give participants greater flexibility in hedging their market positions. Second, it will give participant access to congestion hedges that better align with the requirement of retail access auctions that commit a LSE to multi-year LSE obligations. Finally, the longer-termed products also increase financial participant's opportunities in the FTR Market by increasing the number of FTR products that can be traded in the market."

- PJM filing to Docket No. ER08-1016-000 (May 28, 2008)

[59] PJM. PJM Interconnection LLC. Filing: ER06-150-000., Washington D.C., 2006.

[60] Simultaneous Feasibility Test are further discussed in Appendix B (Section 10).

61 Parmeswaran, Vijay, and Kumar Muthurman. "FTR-Option Formulation and Pricing." Electric Powers System Research (March 26, 2009).

4.2.5 Balancing congestion

Balancing congestion is a real-time imbalance of charges that occurs when the transmission capability in the real-time energy market is less than the assumed availability determined in the day-ahead energy market. In essence, there is less electricity available for transmission than assumed.

On January 31, 2017, FERC ordered that PJM allocate balancing congestion costs on a pro-rata basis to real-time load and exports to solve this issue. Previously, balancing congestion (as defined in the textbox) was assigned to FTR holders, and it caused FTR holders to discount the value of FTRs given they had to absorb a liability (since balancing congestion is typically a negative value). The re-assignment to real-time load and exports was justified because balancing congestion is a settlement based on costs that arise in the real-time market.

This change to the settlement process is consistent with returning congestion payment from LMPs to load, and it also supports the second purpose of FTRs – hedging and promoting forward markets. Given that FTR holders no longer bear the balancing congestion liability, the FTR auction results are less likely to be affected by the risk premiums for underfunding and therefore more reflective of expected congestion in the day-ahead energy market, which means that the price discovery signal provided by FTR auctions would be improved.

"The Commission found that, under these circumstances, the continued inclusion of balancing congestion in the definition of FTRs would result in either the chronic under-funding of FTRs, or the unrealized value of ARRs for certain load serving entities, to the detriment of both participants in PJM's real-time markets and, under certain circumstances, the holders of the underlying transmission rights."

- FERC Order (158 FERC ¶ 61,093) (January 31, 2017)

4.2.6 Surplus transmission congestion charges

On June 1, 2018, FERC accepted PJM's request to shift payment of surplus transmission congestion charges from FTR holders to ARR holders. Starting with the 2018/2019 planning period, surplus congestion has been distributed to load on a pro-rata basis to their positive ARR target allocations.[62,63] PJM requested this change to better align the ARR mechanism with the original purpose of returning congestion payments to load (as described in the textbox below). Surplus transmission congestion charges occur only because the network model used by PJM to allocate ARRs and to clear FTRs in the annual and monthly FTR auctions is under-forecasting the extent of network capacity that is actually utilized in the spot market. So, the existence of surplus

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[62] FERC. 163 F.E.R.C. P61,165. Washington D.C., 2018.

[63] With the change in surplus congestion entitlement, FTR holders will still be fully compensated before ARR holders receive the surplus. See "Federal Energy Regulatory Commission. 163 F.E.R.C. P61,165. Washington D.C., 2018. P. 3"

congestion can be traced to a problem of ARR under-allocation. Therefore, it is reasonable that the load should receive this surplus congestion.[64,65]

> *"PJM states that annual ARRs are currently under-allocated because of "the necessary conservative modeling" required to mitigate against FTR under-funding and FTR revenue inadequacy. […] PJM concludes that the transmission congestion charge surplus is, by definition, the congestion collected for which no risk hedge was allocated. Therefore, to the extent FTRs are over-funded at the end of the Planning Period, returning value back to ARR holders equal to the surplus will mitigate against the fact that the ARRs were under-allocated in the first instance."*
>
> \- FERC Order (163 FERC ¶ 61,165) (May 31, 2018)

4.3 Current ARR/FTR mechanisms

The current ARR/FTR mechanisms are shaped by the changes and modifications made in the past several years, as discussed in the previous sections. Currently, the ARR allocation process has two stages – Stages 1 and 2. Under Stage 1, PJM assigns ARR sources for each zone from resources historically designated to serve load[66] in the zone. Stage 2 has three rounds that allow LSEs to request additional ARRs from various potential ARR source points. Although ARRs are acquired through the annual allocation process, PJM performs a daily ARR reassignment.[67] ARRs continue to be available only as an obligation. The ARR holder can either hold on to its ARR or self-schedule the ARR to convert into an FTR during the annual FTR auctions.

Many FTR products developed in the previous years are still in use today, such as on-peak and off-peak FTR obligations and options. Auction formats such as the monthly and annual FTR auctions are still widely used by market participants to this day. The Long-Term FTR auction, revised to five-rounds instead of three rounds on April 15, 2020, is a continuous part of the FTR mechanism, allowing participants to acquire long-term FTRs with reduced financial risk.[68] Appendix C (Section 11) provides a more detailed discussion on the current ARR/FTR mechanisms in PJM.

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[64] FERC. 163 F.E.R.C. P61,165. Washington D.C., 2018. p. 2.

[65] Notably, in this decision, FERC also clarified that full funding of FTRs is not guaranteed and that FTR holders take on the potential risk of under-funded FTRs.

[66] Initially, this was based on the historical reference year that corresponds to the LMP-based market implementation for the transmission zone. For instance, for ATSI, it is based in 2010, the year that it joined PJM. Starting in 2017/2018 Annual ARR, the retired generators used as eligible ARR sources were replaced with available ones.

[67] This happens when ARRs allocated for the planning period are reassigned on a proportional basis within a zone, as load switches between LSEs (due to retail competition and customer movement between different LSEs).

[68] FERC. 171 F.E.R.C P61,017. Washington D.C., April 2020., p. 3.

5 Selecting the appropriate evaluation criteria (Task 2)

Key takeaways

- LEI selected four criteria -- equity, efficiency, simplicity, and transparency -- to analyze PJM's ARR/FTR mechanisms. These criteria are chosen because they are objective and quantifiable.
- These are also commonly used criteria in regulatory economics and policy design.
- The two purposes behind the creation of FTRs (and ARRs) naturally relate to the issues of equity and efficiency and therefore are of primary importance to the evaluation.
- Transparency and simplicity are supportive criteria that can amplify (or hinder) the achievement of the primary criteria.

Evaluation criteria are vital for structured and methodic analysis. In economics, regulatory design,[69] and policy analysis, efficiency is the criteria of singular importance. Efficiency involves the optimal allocation of resources to those that value them the most. Efficiency can be observed through competitive bidding outcomes in the auctions, which leads to the highest auction prices given expectations about future congestion (and risks), and the highest possible payout to ARR holders (given the auction results), and efficient expectations on future congestion on the transmission network. The former observation supports Purpose #1, while the latter supports Purpose #2.

However, electricity markets are intentionally designed institutions created by policymakers and regulators. A critical goal of these designed institutions and arrangements is to deliver just and reasonable outcomes. Therefore, the fairness of outcomes or equity considerations is also critical. There are also several practical dynamics to intentionally designed institutions. First, it is better if the design and associated rules are clear and straightforward, and therefore less susceptible to uncertainties, assumptions, and controversies. Second, each market participant should have access to timely and accurate data provided in a transparent manner so that they can make efficient decisions.

Consequently, LEI used these four criteria – equity, efficiency, transparency, and simplicity – to assess the ARR/FTR mechanisms. The first two criteria are of primary importance, while the last two criteria are supportive (secondary) in nature, as shown in Figure 16. All four are broadly accepted criteria in regulatory economics based on widely acknowledged industry practices. Economists, judicial experts, and regulators have relied on comparable criteria for systematically

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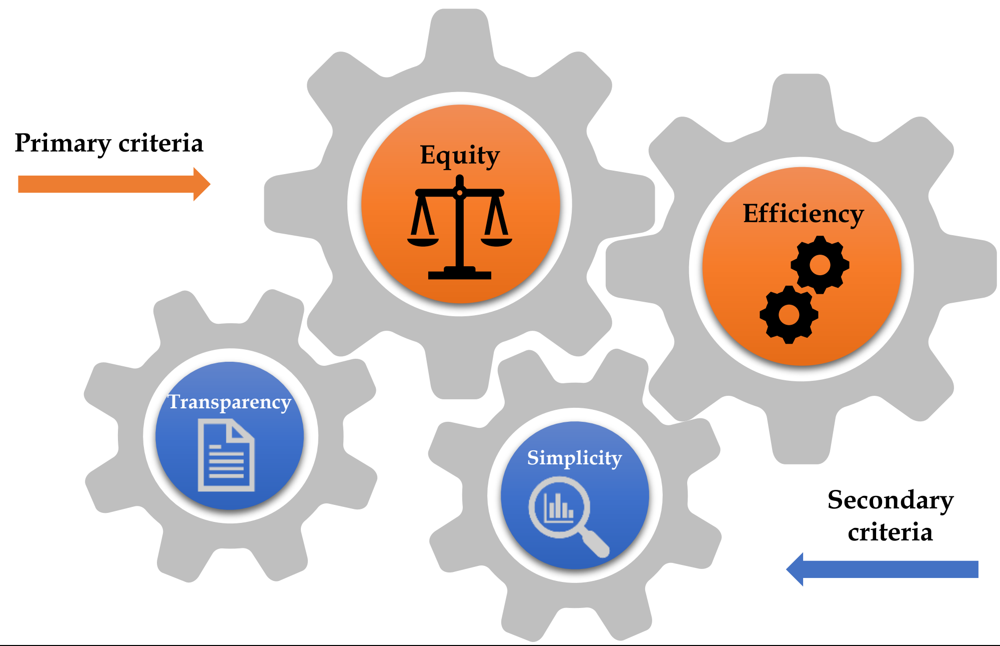
[69] For example, see James C. Bonbright's seminal regulatory handbook, "Principles of Public Utility Rates," published by the Columbia University Press in 1961.

analyzing issues brought before them.[70] Indeed, at the heart of many social policy and regulatory debates lies the age-old question of equity versus efficiency. Similarly, the tradeoff between equity and efficiency is a prominent element of FTR/ARR mechanisms analysis, as we discuss further below.

Figure 16. Criteria used in the evaluation of the ARR/FTR mechanisms



5.1 Primary criteria

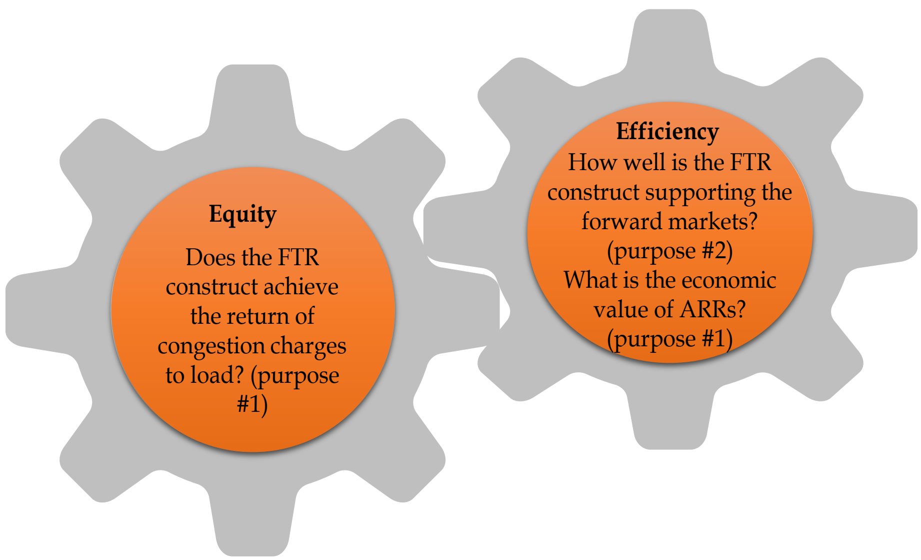
Equity and efficiency are the primary criteria in this analysis, as they are directly linked to the two purposes of the FTR market identified in Task 1. Equity reflects the fair treatment of affected parties (for example, equitable distribution of benefits or profits from the purchase/sale of a good or service). It requires some judgment in the eye of the beholder, but it is also crucial for the overall success of a policy or regulatory decision, as it speaks to the distribution of welfare. In the context of ARR/FTR design, the equity criterion aims to look at whether the existing construct achieves the return of congestion charges to load (Purpose #1). The efficiency criterion also applies to Purpose #1 because the efficiency of the FTR auctions impacts the optimality of the payments to ARR holders. However, efficiency is also a major consideration when thinking about how well the FTR construct supports forward markets (Purpose #2).

Efficiency reflects a state with optimal production and consumption (for example, efficient market prices will reflect the optimal use of a good or service). Competitive markets for a product

[70] For example, FERC frequently speaks to efficiency of regulations and policies, especially as it relates to directives it provides on wholesale market mechanisms. Fairness is also a critical factor, underpinning important concepts like the "just and reasonable" standard.

or service are inherently expected to deliver on efficiency goals; therefore, market mechanisms are preferred over rules-based schemes to ensure efficient outcomes. This philosophy applies to the FTR auctions and the broader electricity market system (consisting of the LMP-based spot markets and forward markets). If the FTR auctions' outcomes are ***allocatively efficient*,**[71] then the price of FTRs will be bought by those that value the product the most. An efficient auction ensures ARR payments are maximized and returned to load. In addition, the auction clearing price will reflect an accurate, market-based expectation about future congestion. This market-based expectation of future congestion is essential to forward markets. In turn, well-functioning forward markets ensure ***dynamic efficiency***[72] in the long run, as characterized by timely and sufficient investment to sustain the lowest possible cost of electricity for load. As such, FTR auction outcomes create an important link between LMP-based spot markets and forward markets for energy.

Figure 17. Equity and efficiency criteria



Equity as a criterion relates to Purpose #1: since load (and other firm transmission customers) pay for transmission service, then they should also receive the congestion charges accrued in the LMP market since these rents are essentially additional charges paid by load in LMPs, because of

71 If an allocation of resources maximizes total surplus, that allocation exhibits efficiency. If an allocation is not efficient, then some of the potential gains from the trade among buyers and sellers are not being realized. Similarly, an allocation is inefficient if a good is not being consumed by the buyers who value it most highly. Source: Mankiw, N. Gregory. "Principles of Microeconomics." Fifth Edition. South-Western CENGAGE Learning (USA). pp. 147-148.

72 Dynamic efficiency reflects the need for industries to make timely changes to technology and products in response to changes in productive opportunities. Source: Havyatt, David. "The Components of Efficiency." Network, A Publication of the Australian Competition and Consumer Commission for the Utility Regulators Forum. March 2017. p. 1.

constraints on the transmission system. Unlike efficiency, considerations around equity are subjective. In other words, an outcome may be equitable from the perspective of one party but inequitable or unfair from the viewpoint of another party. In the context of FTRs and ARRs, subjectivity arises when similarly-sized and similarly-situated loads receive a varying amount of congestion charges.

It is important to acknowledge that there is a natural tension between equity and efficiency. Theoretically, a Pareto-efficient outcome (i.e., a situation where it is impossible to make someone better off without making someone else worse off) can be deemed inequitable in its division of social welfare (there may be winners and losers, and there is no guarantee that every market player is allocated the same amount of "social welfare").[73] Changing the distribution of social welfare (i.e., moving around the rent transfers) may require reallocation (or willingly incurring some "leakage" as part of the redistribution process).[74]

The two original purposes for the creation of FTRs are examples of a situation involving an equity-efficiency tradeoff. Some market participants raised concerns that there are "leakages" of congestion charges in the existing FTR auction design. This then impacts the congestion charges collected by PJM and returned to load (Purpose #1). From an equity perspective, this can be a concern. However, if we take a holistic approach and consider the long-term efficiency in assessing the FTR design, these "leakages" are not strictly an economic loss but rather are viewed as costs for supporting hedging opportunities in the forward market, as discussed in Section 6.

5.2 Supporting criteria

The supporting criteria - transparency and simplicity - facilitate equity and acceptance of fair distribution of the congestion payments to load. Further, these criteria can support competition and reduce administrative burden and transaction costs.

Transparency promotes equitable outcomes, as it allows stakeholders/market participants to recognize if there are equity challenges in the outcomes. The availability of relevant information

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73 For example, an efficient market outcome may involve a situation where suppliers in the aggregate capture a large profit (also known as a producer surplus), while the surplus received by consumers is relatively small (because the difference between consumer's willingness to pay and the actual price is relatively small). Government intervention in this market could require a transfer of rents (surpluses) from the suppliers to consumers, but such a transfer would not improve the efficient market outcome. And in fact, such a transfer may inhibit continuation of an efficient outcome in the longer run, by changing incentives for sellers and consumers. Under positive economics, the focus falls on the fact-based assessment of "what is" – for example, efficiency and the size of the surpluses. In contrast, normative economics recognizes the presence of value judgements, such as fairness. As such, maximization of social welfare is the heart of positive economics, while allocation of social welfare is a focus of normative economics. Despite the fundamental differences, positive and normative economics are intertwined. In particular, positive views about how the world works affect normative views about what policies may be desirable.

74 Okun, Arthur M. "Equality and Efficiency: The Big Tradeoff," The Brookings Institution, Washington D.C. Revised Edition. 2015. p. 4.

supporting all market participants' understanding of the value of the product is essential for a well-functioning market. Also, market participants need timely access to the information to make informed decisions. It has been long recognized that information asymmetries are a major obstacle in markets.[75] In this way, transparency can also support efficient outcomes, as it implies that all parties can 'see' the same information, a critical first step in resolving information asymmetries that can impede competition and efficient outcomes. If the same information is available and understandable to all market participants in the FTR market, it will create a level playing field and reduce perceived risks,[76] which should yield more aggressive competition and maximize FTR auction revenues. Simplicity advances the goals of efficiency by reducing administrative burden and transaction costs, which can serve as a barrier to efficient outcomes (however, over-simplification is also a potential problem and can work against both equity and efficiency objectives). Data should be organized and digestible. Simpler theories should be preferred to more complex ones, as long as it does not compromise the market's functionality. Simplicity is often associated with feasibility, and that encourages public acceptance of outcomes.[77]

5.3 Turning abstract criteria into quantifiable metrics

LEI acknowledges that the four selected criteria are theoretical, reflecting principles rather than a concrete metric. However, it is possible to describe and elucidate these criteria, so they become grounded in the factual characteristics that represent PJM's ARR/FTR mechanisms. LEI developed a series of questions related to the ARR/FTR construct to describe how the criteria should be implemented in the analysis – these questions provide a bridge to the analyses that we perform in Section 6.

Equity: **Are firm transmission service customers getting priority rights to the transmission network they pay for through regulated rates?**

- ✓ In the short-term, does load (and other firm transmission rights customers) have an opportunity to have sufficient congestion charges returned to them by nominating ARRs to cover the congestion charges paid?
- ✓ Do all LSEs have the same opportunity to have sufficient congestion charges returned? In other words, are congestion charges returned fairly among LSEs?
- ✓ Is the dual system of rights – ARRs and FTRs – producing effective outcomes for load and other firm transmission service customers?

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[75] Information asymmetry refers to the situation in which different agents in an economic transaction might have different amounts of information. It is considered a type of market failures as it often prevents market equilibria to be Pareto optimal.

[76] Perceived risks include phenomena like the winner's curse. The winner's curse is the situation in which a winning bid pays more than the true value of an item. This concept was first discussed in Capen, E. C., R. V. Clapp, and W. M. Campbell, "Competitive Bidding in High-Risk Situations." *Journal of Petroleum Technology* 23 (June 1971). pp. 641-653.

77 Bonbright, James C. "Principles of Public Utility Rates." Columbia University Press, 1961. p. 291.

- ✓ Does the presence of non-load entities participating in the FTR auctions distort the fair allocation of congestion charges to load and other firm transmission service customers? Are the FTR profits for non-load entities commensurate with associated risks they are taking?

Efficiency: **Are the FTR auctions efficient and supporting bilateral (forward) markets and encouraging investments that benefit load and other firm transmission service customers?**

- ✓ Are the FTR auctions efficient? Are there any market failures that may undermine the efficiency of FTR auction outcomes?
- ✓ Is the FTR auction informing expectations about future transmission system congestion?
- ✓ Is the design construct of FTRs aligned with bilateral markets? Are there bilateral energy market transactions that follow the point-to-point construct of FTRs and sink into a node?
- ✓ Is there evidence of price discovery activities originating out of the FTR auctions and affecting the forward markets?
- ✓ In the longer-term, are ARRs and FTRs signaling, contributing, or otherwise supporting transmission and generation investment?

Transparency: **Are the ARR and FTR processes transparent and the results publicly available in a timely manner? Are market participants confident that the ARR process and the FTR auctions are conducted in an unbiased and competitive fashion?**

- ✓ Is the information about ARR allocation available to all market participants?
- ✓ Is the information released at the same time to all LSEs?
- ✓ Are the information and data related to FTR auctions released in a timely manner?

Simplicity: **Are the consequences/risks of operating in the ARR process well understood, and is acquiring FTRs relatively easy for market participants? Are there uncertainties in the process due to the complexity of the ARR/FTR mechanism?**

- ✓ Is the information and data related to the FTR auctions released in a format that is easy to understand?
- ✓ How complicated are the rules for ARR allocation process and the FTR auctions?
- ✓ Are any aspects of the ARR/FTR mechanism unclear?
- ✓ Are there assumptions that are not accessible to market participants? Do these assumptions drive outcomes?
- ✓ Do the complexity of the rules and/or institutions provide a competitive advantage to one sub-set of potential participants?

6 Evaluating the existing ARR/FTR construct (Task 3)

Key takeaways

- Based on LEI's extensive quantitative and qualitative analysis, PJM's existing ARR/FTR mechanisms are working reasonably well, especially after recent enhancements.
- The current path-based construct also continues to be relevant in the present day given the significant amount of load that is contracting bilaterally or self-supplying.
- The dual system of property rights (encompassing ARRs and FTRs) create value for load and should be preserved. ARRs provide flexibility to load and the payouts to load from holding ARRs are satisfactory (factoring in the impacts of anomalous weather events).
- Overall, FTR auctions are generally efficient and should be retained with minimal changes. Non-load entities also have been taking more high-risk/high-return opportunities in the FTR market, but at the same time providing liquidity to the market. Their participation in the FTR auctions results in benefits such as reducing long-run energy costs as well as lowering transaction costs for hedging and contracting bilaterally.
- ARR allocation process may result in equity issues between LSEs and should be reformed. Focus on the ARR allocation process is also consistent with concerns raised by stakeholders during the FGDs.
- The existing design produces short-term and long-term benefits for load in PJM. With respect to Purpose #1, on average, over 80% of congestion charges collected annually in the day-ahead energy market have been returned to load over the years. Recent enhancements to market rules have further increased the amount of congestion charges that are returned to load. With respect to Purpose #2, the illustrative long-term benefits achieved through various forward market mechanisms amount to as much as $1,207 million a year. Even at the low-end estimate of the long-term benefits ($523 million), long term benefits are likely to exceed the perceived costs (e.g., the "leakage") to load, which has averaged $223 million a year in the last six years.

LEI began Task 3 by researching and collecting data from PJM and the IMM on the specific outcomes in recent years under PJM's ARR process and FTR auctions. LEI also talked with stakeholders to obtain their opinion on the current ARR/FTR mechanisms' advantages and disadvantages. As part of this stakeholder engagement, LEI received input on proposed modifications to the market design to mitigate perceived deficiencies and enhance the reported strengths. LEI also talked to the IMM and PJM staff and gathered data relating to the operations of the ARR process and FTR auctions and suggestions for potential changes. Finally, LEI conducted an independent analysis of the existing ARR/FTR mechanism's functionality in relation to the two purposes.

6.1 What are the stakeholders' viewpoints on the current ARR/FTR construct?

LEI engaged with 37 stakeholders[78] representing LSEs, transmission utilities, generation owners, power marketers, financial traders, and different classes of consumers through four three-hour FGD sessions, a 56-question follow up survey, and additional one-on-one telephonic interviews.[79] From these stakeholder engagements, LEI observed that many ARR participants and FTR auction participants were generally satisfied with the current ARR/FTR design and would prefer to have incremental improvements and enhancements rather than a complete overhaul of the ARR/FTR market design. Appendix D (Section 12) provides a more detailed description of the results of the FGDs and the survey questionnaire.

6.1.1 Views on the ARR process

On the ARR allocation process, LSEs were generally satisfied with Stage 1A of the ARR allocations. Furthermore, they were appreciative of the recent changes made by PJM to prevent underfunding. Nevertheless, several stakeholders raised specific concerns on the ARR allocation process, including insufficient ARR allocation, quantity, frequency, and the limited granularity of the ARR products. Some also stated that the current ARR mechanism does not enable customers to access the resource paths needed to hedge the congestion risk relative to their contracted resource portfolios, especially new generation. Due to these concerns, several LSEs and representatives of LSEs voiced a strong interest in seeking improvements in the ARR allocation process. Some enhancements that were suggested included: more frequent ARR allocations and nomination periods, flexibility with self-scheduling ARRs, and more granular ARR products aligned better with the range of FTR products currently available.

The follow-up survey further expanded on the participants' interest in ARR improvements in a quantitative manner. As shown in Figure 18, there was a near 50-50 split in terms of interest in more granular (time of use) ARRs. In contrast, most of the survey's respondents supported a monthly ARR allocation process, as shown in Figure 19. The respondents who were not interested in increasing ARR granularity and allocation frequency were concerned that such changes to ARRs would dilute the value of the allocated ARRs.

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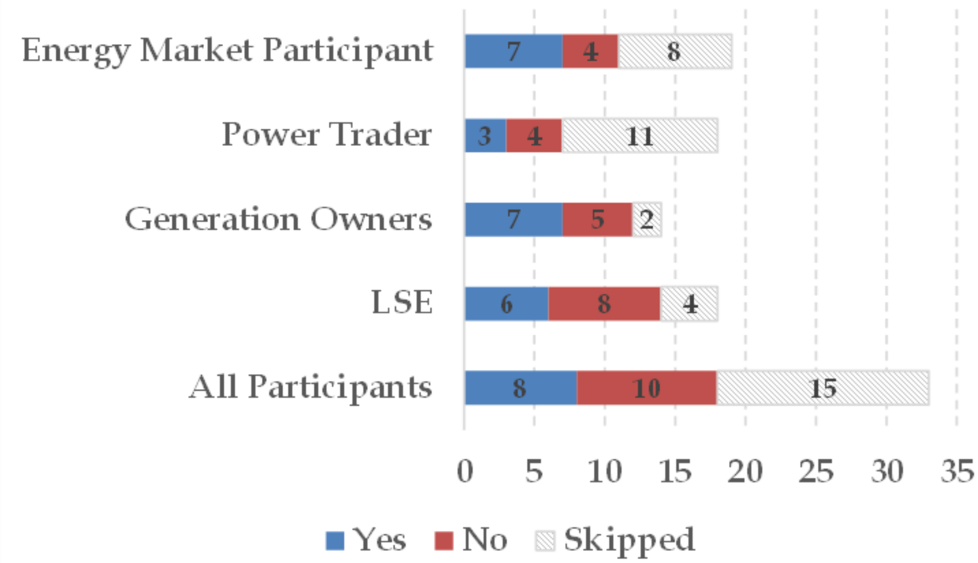
[78] This number excludes interviews with IMM, Nodal Exchange, and ICE.

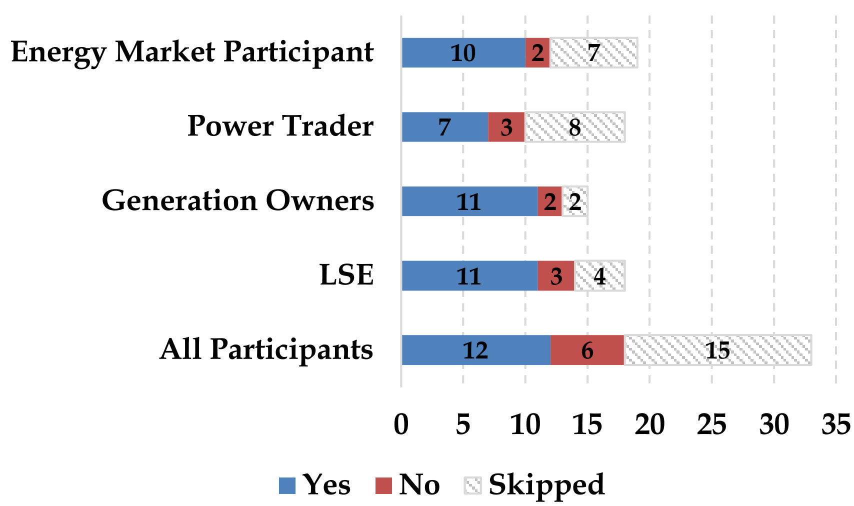
[79] In late August 2020, PJM solicited feedback from all of its market participants and members and opened invitation to over 1000 members of the ARR FTR Market Task Force and Market Implementation Committee to participate in LEI's focus group discussions.

Figure 18. Interest in ARR differentiated by calendar periods, such as on-peak, off-peak, weekend, 7x24



Source: FGD Questionnaire Survey, Question 17.

Figure 19. Interest in the monthly allocation of ARR entitlements

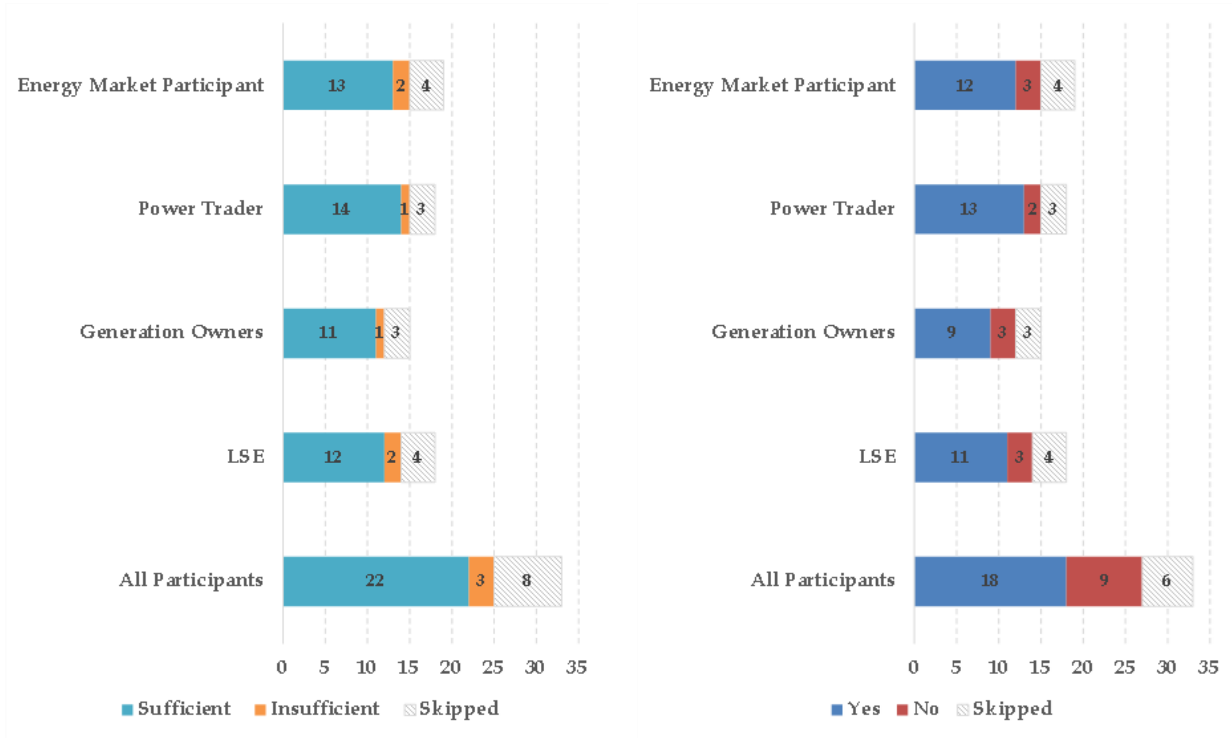


Source: FGD Questionnaire Survey, Question 16.

6.1.2 Views on the FTR auctions

With respect to the FTR auction design, most LSEs and other entities trading FTRs were in favor of the current portfolio of available FTR products, and they felt that the frequency of the FTR auctions was sufficient (as shown in Figure 20). The majority of stakeholders agreed that the FTR market provides sufficient price discovery for the forward market and presented PJM spot market participants (including load) with adequate hedging opportunities for bilateral transactions. When asked about FTR auctions' competitive nature, there was consensus that the auction outcomes were competitive because of the transparency of outcomes (and therefore profits and losses of every FTR bought). However, one LSE participant remarked on the "leakage" of FTR profits to non-load entities. Non-LSEs (i.e., financial participants) expressed complete satisfaction with the current FTR market and felt their commercial objectives were being met. They advocated for no major changes.[80]

Figure 20. Stakeholder views on the FTR auction, sufficiency vs. satisfaction



Source: FGD Questionnaire Survey, Questions 42 and 43.

LSEs and other stakeholders acquiring FTRs for hedging also suggested that the FTR products could evolve to better meet the needs of intermittent energy sources, which operate in periods that may not align with traditional peak and off-peak designations. Furthermore, both non-LSEs and LSEs suggested that FTR products could be further enhanced through greater granularity

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[80] Although the financial participants advocated for no major changes, a handful of participants – LSEs and financial participants - stated that they would like to see relaxation of the current FTR forfeiture rule (which they assert is overly punitive and not parsimonious) and the reforms to credit policies. As noted earlier, this report does not touch upon credit policies, as those are being addressed through a separate Task Force.

(off-peak weekday and off-peak weekend) and a reservation price system on FTR auctions or other corrective actions (so that FTRs would not be sold at excessively low prices). These recommended enhancements focused primarily on Purpose #1. The follow-up survey also expanded on the participant's interest in the FTR auction and product improvements.

Finally, some participants mentioned that transparency should be improved. More specifically, they said that changes to the network model should be published (and explained). There were also practical concerns raised about software compatibility issues (for uploading ARR nominations and FTR path requests) and timing of award notification (ARR awards and FTR auction results). LEI assessed opportunities for improvement on these issues with PJM and, independently, based on comparative review of procedures in place at other US RTOs/ISOs.

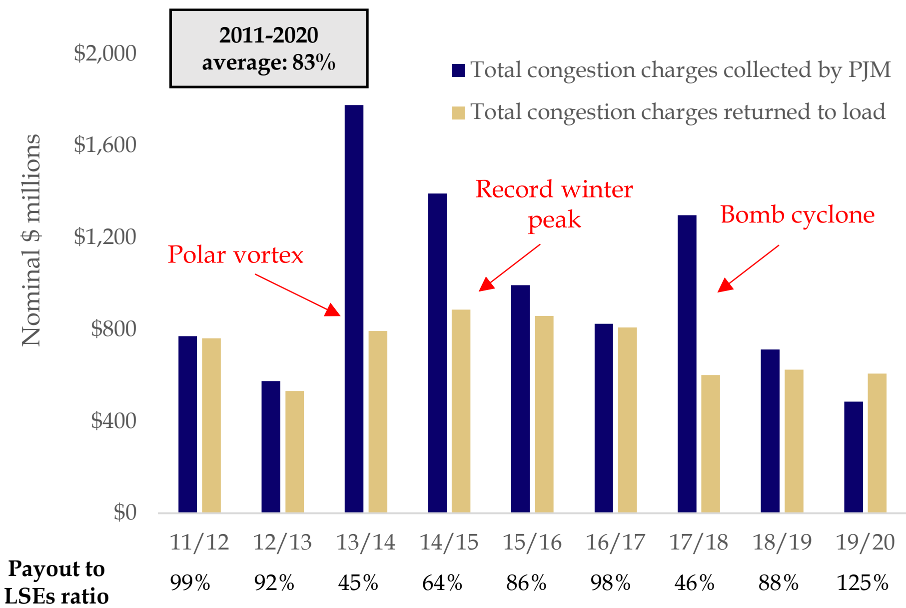
In summary, market participants do not want an overhaul of the ARR/FTR construct and prefer incremental enhancements in the ARR allocation process, additional flexibility with self-scheduling, and better alignment of ARR and FTR products.

6.2 Is load getting a return of congestion charges collected as a result of the LMP-based spot market?

As described in Section 3, the LMP system, combined with the uniform clearing concept adopted in PJM's energy market, results in a situation where the sum of LMP payments collected from load exceeds the sum of LMP payments made to generation. This excess amount of congestion charges should be refunded to load in recognition of the fact that load already pays for transmission service through regulated rates. On an aggregate basis, over the last nine years, on average over 80% of congestion payments have been returned annually to load.[81] The year-by-year outcomes are captured in Figure 21, where the total congestion charges collected by PJM (blue bar) are compared to the total congestion charges returned to load (yellow bar). The data below the bar chart shows the ratio of these two variables. The year with the highest ratio was 2019/20 at 125%, and the year with the lowest ratio was 2013/14 at 45%.

[81] LEI did not find any direct evidence that FERC anticipated or required that the FTR (and ARR) mechanism would return *exactly* 100% of the annual congestion charges collected in a given year to load.

Figure 21. Total congestion payments collected by PJM versus congestion charges returned to load



Note: Total congestion collected by PJM includes both day-ahead congestion as well as balancing congestion, while the congestion charges returned to load include ARR credits, FTR credits (from self-scheduled ARR paths), balancing and mark-to-market charges (starting 2017/18), and surplus allocation (starting 2018/19). "Payout to LSEs ratio" represents congestion charges returned to load as a percentage of total congestion collected by PJM.

Source: LEI analysis of ARR and FTR data provided by PJM.

There are several reasons why this ratio is not exactly 100% -- all of which relate to the decision to use a path-based dual system of rights (ARRs and FTRs) where the trading of FTRs informs the value of ARRs:

1. **Forecast errors during FTR auction.** Over the nine planning years shown in Figure 21 above, ARR credits have represented an average of 70% of the total congestion charges returned to load. ARR credits depend on FTR auction prices, while the congestion payment collected by PJM is based on actual CLMP during spot market operations (day-ahead CLMP and balancing congestion). Since FTR auctions happen before spot market operations, there are naturally forecast errors between predicted congestion (in the FTR auction) and congestion charges finally collected by PJM (in the spot market). This is most noticeable in years with anomalous weather, resulting in a situation where actual congestion charges are materially higher than what would usually be expected. Such weather-driven events occurred in 2013/14 (Polar Vortex), 2014/15 (record winter peak

London Economics International LLC
717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com

load), and 2017/18 (Bomb Cyclone).[82] In those years, the ratio was low because market participants did not fully anticipate the amount of congestion charges during the annual FTR auctions. In contrast, in the most recent planning year for which we have data (2019/20), realized congestion charges have been lower than what was predicted in the FTR auction, which could also drive the ratio to be over 100%. The forecast error inherent in such an outcome is related to the impact of the COVID-19 pandemic on demand (lower demand led to lower congestion in the day-ahead energy market).[83] If anomalous weather years of 2013/14, 2014/15, and 2017/18 are excluded, the total congestion charges returned to load would be 98% of congestion charges collected by PJM.

2. **Difference between modeled network capability during FTR auction and spot market operations.** The quantity of ARR allocated to load depends on the network model used by PJM. The ARR may be higher or lower than the actual network transmission capacity during day-ahead and real-time operations. FTR target allocation is calculated based on allocated MW times the difference between sink and source CLMP, while congestion charges collected by PJM are based on the actual flow of MW across a constraint multiplied by the difference between sink and source CLMP. Therefore, when actual flows on the transmission system differ from the projected flows in the SFT employed to solve the FTR auction, the total congestion charges collected by PJM may be greater (or less) than the FTR target allocation. If there is excess network capacity during spot market operations, this will result in surplus congestion. Before the 2018/19 planning period, surplus congestion was allocated to FTR holders. After 2018/19, the surplus congestion is allocated to ARR holders based on the positive ARR target allocation value.

3. **Non-load FTR market participants may earn a profit on their FTR positions, reducing the amount of congestion charges that would be returned to load.** FTR auction outcomes drive the value of ARRs for those entities that decided to hold onto their ARR paths. These LSEs are indicating a preference for the certainty of knowing their ARR target allocations in advance of the spot market. The FTR holders that are buying FTRs are taking on the risk of uncertain congestion charges and therefore taking on the risk that the LSEs are shedding. The FTR product is essentially swapping fixed for variable and thus inherently risky, meaning FTR holders will want to be compensated for that risk. The profits earned by non-load entities in the FTR auction are remuneration on the risk – in many ways, similar to an insurance premium. This net profit earned by non-load FTRs holders is what some stakeholders refer to as "leakage" because it is not returned to load (which we discuss further in Section 6.9 below).

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[82] PJM. "Winter operations review." April 16, 2020. <https://pjm.com/-/media/committees-groups/committees/oc/2020/20200416/20200416-item-08-winter-operations-review.ashx>

[83] PJM. "Recent COVID-19 Load Impacts." October 6, 2020 <https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20201006/20201006-item-07a-recent-covid-19-impacts.ashx>

An additional design element in the current ARR/FTR mechanism exacerbates the difference between payment to load versus congestion charges collected by PJM. There are FTR paths that market participants can purchase in the FTR auction, which are not available for load to nominate in the ARR allocation process. For example, FTR market participants can purchase an FTR path where both the source and sink node is a generator bus (also known as "gen-to-gen" paths).[84] Some LSEs purchase select gen-to-gen paths in the FTR auction, but the majority of gen-to-gen paths are purchased by non-load entities. Any net profits earned on these gen-to-gen FTR paths by non-load, and for that matter, other paths that are sold to non-load in FTR auction but not permitted for ARR allocation, contribute to leakage.

Overall, recent changes in market rules have improved the amount of payout to load on the aggregate level as it has allowed PJM to prioritize load as the recipient of any residual funds. However, given that there have been only two complete planning years since the surplus allocation rule change and the 2019/20 planning year experienced below normal congestion, it is difficult to discern a long-run average in the ratio.[85] Nevertheless, load has received back on average a majority of the congestion charges collected in the LMP-based spot market.

6.3 Are there any issues with the return of congestion charges to load?

The allocation of returned congestion charges between different LSEs may be inequitable based on observations of zonal differences in the quantity of ARRs allocated and offset received by LSEs. According to the Coase theorem,[86] the initial allocation of property rights should not matter if the recipients of those rights can trade with minimum transaction costs. However, with respect to the PJM ARR/FTR mechanism, there are limitations on those property rights. Some property rights that are subject to allocation (such as the ARRs) are not tradable. Rather, LSEs have the option to convert their ARRs to FTRs, which then become tradable. In addition, some portion of the value of ARRs is not traded in the conversion to FTRs because the surplus congestion allocation remains a function of the initial ARR target allocation. Moreover, the surplus allocation has represented a material share of the total amount paid to load. This observation raises concerns that there may be inequity issues among LSEs.

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[84] One exception is that the path is clearing at zero price. According to the PJM Operating Agreement Schedule 1 Section 7.3. "Financial Transmission Rights with a zero-clearing price will only be awarded if there is a minimum of one binding constraint in the auction period for which the Financial Transmission Rights path sensitivity is non-zero."

[85] It should also be noted that in the last two years, PJM has not faced as extreme weather (e.g., 2013/14, 2014/15, 2017/18), and COVID-19 has lowered electric load and consequently network congestion. Therefore, just using two years of observations is not conclusive.

[86] See footnote 52.

6.3.1 Determining "equitable allocation" requires judgment

It should be noted that the definition and determination of an "equitable allocation" requires judgement. The use of a historical gen-to-load path allocation was a reasonable judgment call in the 1990s at the time of deregulation, given that utilities typically built generation in their local service territories, and therefore the gen-to-load ARR paths would provide a "perfect hedge" for LSEs using local generation to serve local load. However, continued ARR allocation using historical paths may no longer provide the same opportunity to LSEs as it did over 20 years ago. For example, over 1.5 GW of wind generation came online since 2017 with executed bilateral agreements (PPAs).[87] These supply contracts would not be part of the historical gen to load paths that load is entitled in the ARR allocation. In Section 6.6, we provide further details about the mismatch in the current ARR allocation process between ARR paths and actual energy flow.

In examining alternative allocation mechanisms for ARRs, there may ultimately be winners and losers because LSEs would be comparing proposed allocation schemes relative to the outcomes under the existing scheme. Therefore, it will be essential to determine upfront how to systematically evaluate equity from a societal perspective rather than the narrow perspective of a given LSE. PJM and stakeholders need to agree on allocation principles then, with this definition in place, PJM can measure the relative level of equity improvement created by changing an allocation rule across all LSEs. For example, use of a mean-squared-error test to compare different allocation outcomes to a certain benchmark (based on the principles mentioned above, e.g., the "ideal allocation").[88]

Figure 22 presents an illustrative example of how the relative level of equity of two allocation methods can be compared using the mean-squared-error approach. First, we will need an "ideal allocation" to use as a benchmark. This could be the reference allocation using an alternative allocation scheme. Then, we calculate the square of the difference between the actual (current) allocation and the ideal allocation for each LSE and average this squared error. If the mean-squared-error of one allocation method is higher than the other, we can deem the method with the higher mean-squared-error to be less equitable.

[87] LEI's research involved looking at news related to the projects and the developers, as well as financial and annual reports. For projects that did not disclose publicly their financing terms, LEI reached out to the company's communications and investor relations teams to request this information.

[88] One reason to use mean-square error is that it gives a bigger weight to differences that are large. For example, if one LSE is very unfairly treated (e.g., getting no congestion charges back while they should be ideally getting a material amount back), the mean-square error approach will give this unfair treatment a larger weight as compared to a large number of LSEs having a slight deviation of congestion charges returned against the ideal allocation.

Figure 22. Illustration of using a mean-squared-error metric to measure equity

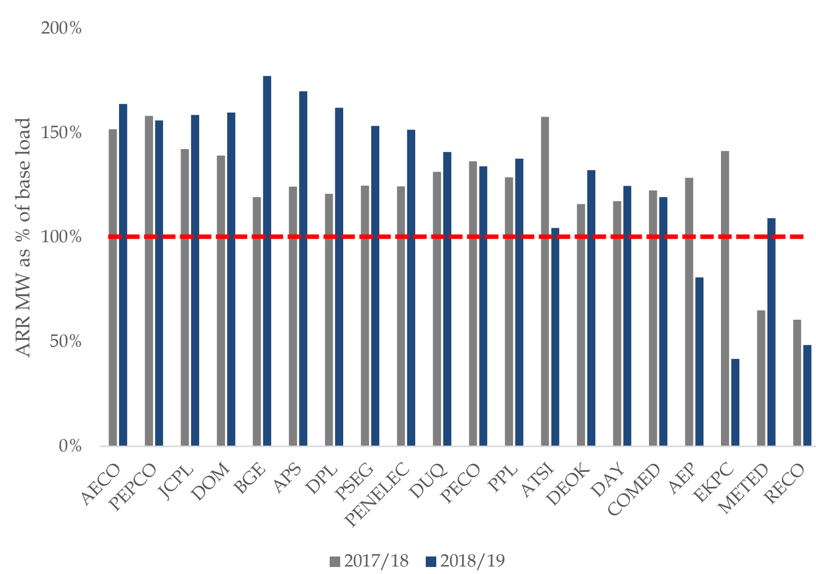
	Ideal allocation	Allocation A	Error squared	Allocation B	Error squared
LSE A	100	80	400	95	25
LSE B	50	60	100	70	400
LSE C	20	30	100	5	225
Average	**57**	**57**	**200**	**57**	**217**

6.3.2 The current ARR allocation method may have resulted in inequitable allocation among LSEs

Even though what is an "equitable allocation" may be a subjective measure, grounding the analysis in principles and asking methodic questions about whether the principles have been met can lend objectivity to the evaluation of equity. For example:

- Has each transmission zone (as proxy for inter-LSE allocation) obtained sufficient ARRs to cover their baseload congestion risk exposure?
- How much do congestion charges returned to load on a zonal basis depend on the ARR path's level of congestion and decisions made by the load (to hold ARR or to self-schedule)? The answer depends on how much of the congestion charges returned to load is "socialized" through surplus allocation.

Figure 23. Allocated ARR MW vs. baseload, by zone (2017/18 and 2018/19)



Source: LEI analysis based on data provided by PJM staff.

LEI analyzed the system capacity cleared in the ARR allocation process,[89] grouped by transmission zones, and compared the quantity of ARRs against baseload demand in each zone. In the planning periods 2017/18 and 2018/19, four zones did not have sufficient ARR MWs allocated to cover their baseload, as presented in Figure 23. Since Stage 1A of the ARR allocation process guarantees LSEs to obtain enough ARRs to cover their zonal baseload,[90] under-allocation of ARRs relative to baseload should not have happened. There are two possible reasons why some LSEs did not receive sufficient ARR allocation relative to their baseload:

1. The load zone does not have generation resources, resulting in LSEs in the zone having no available ARR paths to nominate during Stage 1A and 1B of the allocation process. This is the issue faced by all the LSEs in the RECO zone;

2. Since the ARR allocation process requires LSEs to submit a nomination request to PJM actively, insufficient ARR allocation may also result from LSE inaction or an active decision not to accept an ARR path that was allocated initially because of the LSE's expectations about the potential negative value of the ARR obligation.

In both cases, the choice of ARR paths, under the historical generator to load paradigm, is a limiting factor. This is particularly concerning because, under the current settlement rules, surplus allocation to load is based on the pro-rata ***positive*** ARR target allocation, regardless of whether the LSE has self-scheduled its ARRs into FTRs. If an LSE is not given an adequate opportunity to nominate ARRs (because there are no eligible paths or the expected value of the ARR path obligation is negative), it will not be eligible to receive any surplus allocation from PJM. The inequity is further magnified by the fact that surplus allocation has been a material share of congestion returned to load in the past two planning periods, as further discussed below.

The situation around surplus allocation results in a condition where the entire set of property rights associated with ARRs is not effectively assigned to load. LSEs can only buy or sell the portion of the ARR property right associated with DA congestion charges by (1) holding the ARR, which effectively means getting a fixed payment for variable DA congestion charges, or (2) self-scheduling to convert to an FTR and then selling the FTR in subsequent auction rounds. There is no way for an LSE to buy or sell the surplus allocation component that comes with ARRs. In other words, the initial ARR allocation impacts how much payout load would receive, and such allocation cannot be fully traded between market participants. This implies the conditions required for Coase Theorem to hold are not fulfilled.

Furthermore, based on LEI's analysis of total congestion charges returned to each zone, a principles-based relationship is lacking in the zonal distribution. Congestion charges returned to

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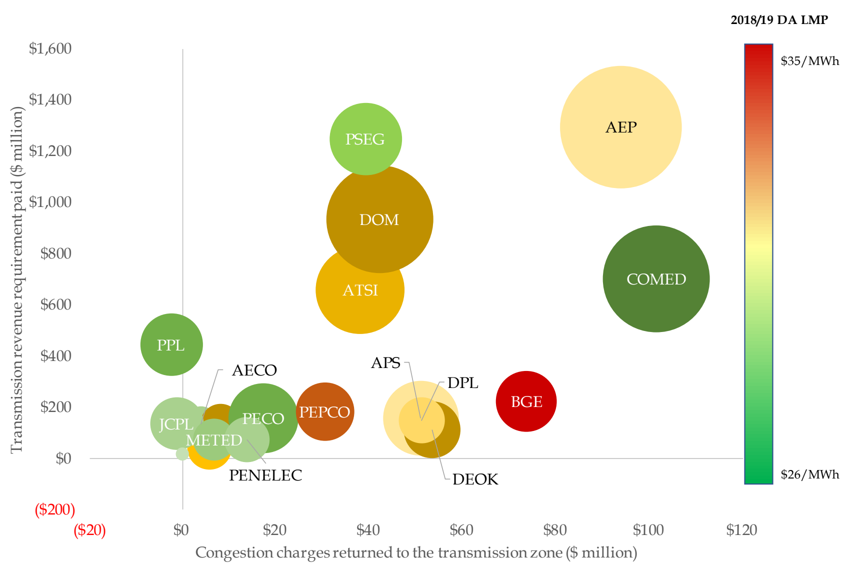
[89] ARR cleared MW is the total ARR nominated and awarded after the SFT. See Appendix C (Section 11.1) for the discussion on the ARR allocation process.

[90] Defined as "the lowest daily zonal peak load from the twelve months period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone." Source: PJM Manual 06 Section 4.2.

load do not appear to be proportional to the total energy consumed in each zone, the total transmission revenue requirement collected from end-users in each zone, nor the average LMP in each zone, as presented in Figure 24. Such an observation raises questions around equitableness. In the figure, each circle represents a transmission zone. The x-axis represents the congestion charges returned to load. The y-axis represents the transmission revenue requirement paid by each zone. The size of the circle is proportional to the baseload MW of each zone. Finally, the circle's color represents the 2018 and 2019 average LMP of the zone, with the greener circles having a lower LMP and the redder circle having a higher LMP. To evaluate the equity of the distribution of congestion charges returned between LSEs, we evaluated the figure for patterns:

- if the congestion charges returned were proportional to the transmission revenue requirement paid in each zone, the circles should line up linearly – they do not;
- if the congestion charges returned were related to the demand in the zone, then the circles would be arranged in order from smallest to largest – they do not follow this pattern; and
- finally, the redder the color of a circle, the higher the 2018 and 2019 annual average LMP recorded for the zone. If the color pattern of the circles followed a green-yellow-red "heat map" alignment, then the congestion charges returned to LSEs would be related to LMPs, but this is not the case here.

Figure 24. Congestion returned to load versus transmission revenue requirement paid, baseload MW, and average LMP (2018/19)

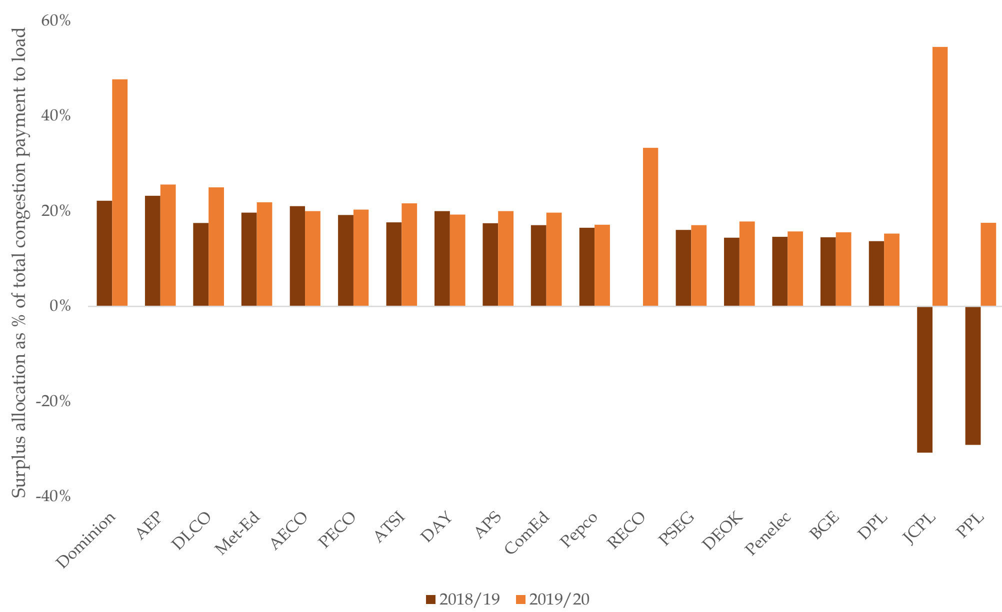


Note: Each circle represents one transmission zone. The size of the circle is proportional to the baseload MW of the transmission zone.

Source: LEI analysis of data provided by PJM.

According to PJM, the surplus congestion should be returned to load because when "FTRs are over-funded at the end of the Planning Period, returning value back to ARR holders equal to the surplus will mitigate against the fact that the ARRs were under-allocated in the first instance."[91] Under this rationale, there is no inherent reason why surplus should be returned to ARR holders entirely based on the pro-rata of just positive ARR target allocations. Given PJM allocates ARR to load is because "of their payment of the embedded cost of the Transmission System ***through firm transmission rates***"[92] (emphasis by LEI), alternative allocation factors may be more appropriate.

Figure 25. Surplus allocation as a percentage of congestion payment to load (2018/19 and 2019/20)



Source: LEI analysis based on data provided by PJM staff.

Since the change of market rule to allocate surplus to load (instead of to FTR holders), the surplus has become a non-trivial share of congestion payments returned to load. Surplus congestion has averaged 18% and 21% of total congestion charges paid to load in 2018/19 and 2019/20 planning periods, respectively. As presented in Figure 25, surplus congestion as a percentage of total

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[91] PJM. "Re. PJM Interconnection L.L.C., Proposed Modifications to the Operating Agreement and Tariff re: Allocation of Surplus Day-ahead Energy Market Transmission Congestion Charges to Auction Revenue Rights Holders" Docket No. ER18-1245-000 March 30, 2018, P. 5. <https://www.pjm.com/directory/etariff/FercDockets/3563/20180330-er18-1245-000.pdf>

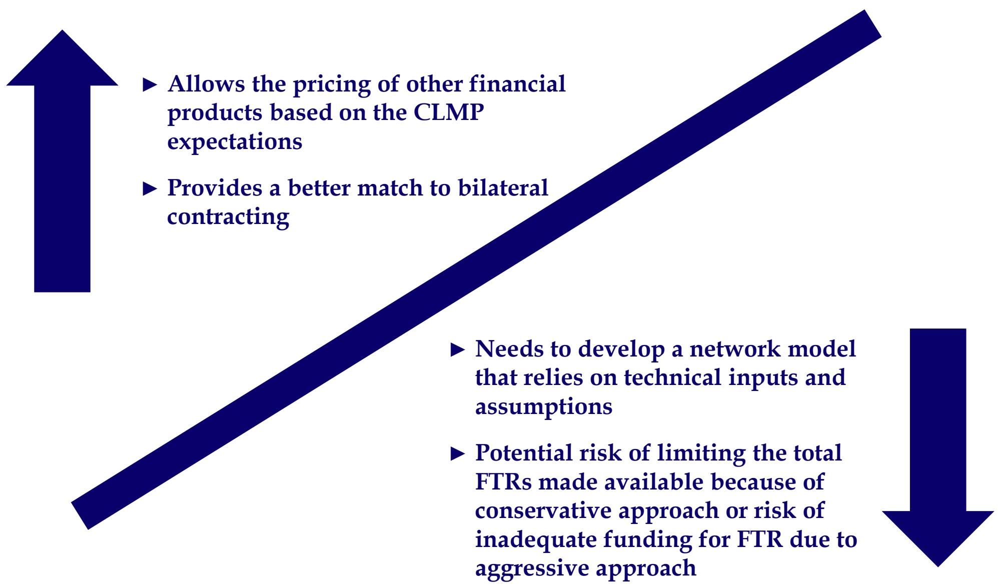
[92] PJM. "PJM Interconnection L.L.C., Proposed Modifications to the Operating Agreement and Tariff re: Allocation of Surplus Day-ahead Energy Market Transmission Congestion Charges to Auction Revenue Rights Holders, Docket No. ER18-1245-000" March 30, 2018. <https://www.pjm.com/directory/etariff/FercDockets/3563/20180330-er18-1245-000.pdf>

congestion payments has exceeded 50% in some zones.[93] In other instances, the zone received a net negative congestion payment (mostly due to balancing congestion and mark-to-market charges being negative), but its positive ARR target allocation resulted in surplus allocation being in the opposite direction to the total congestion payments to load (this occurred for JCPL and PPL zones).

6.4 What are the advantages and disadvantages of the path-based construct underpinning FTRs (and ARRs)?

Like all other US RTOs/ISOs with an FTR mechanism, PJM's ARR/FTR mechanism uses a path-based (or point-to-point) construct where each product traded has a source and sink node. There are both advantages and disadvantages to the path-based construct, as summarized in the figure below.

Figure 26. Advantages and disadvantages of the path-based construct



Advantages

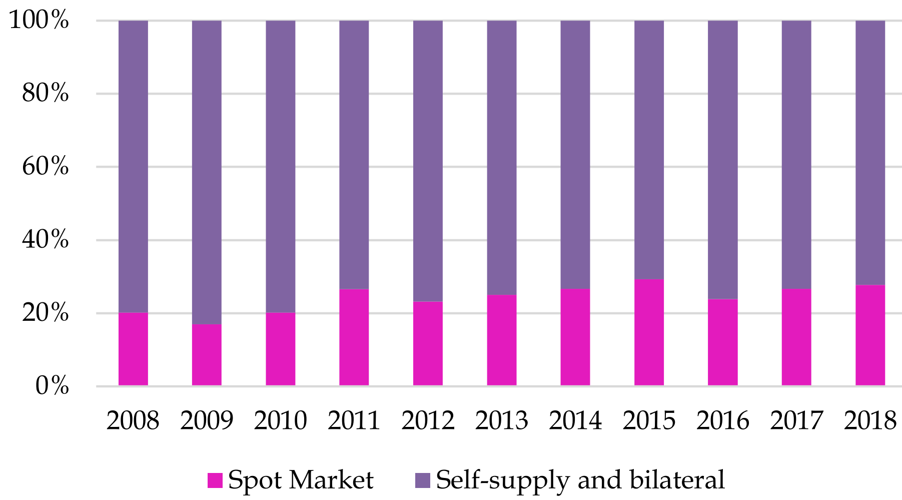
The sale of path-based products results in CLMP expectations at each node with an FTR transaction, which allows the pricing of other financial products based on these locationally-specific expectations. In 2019/20 annual FTR auction, 1,892 unique nodes have been traded, of which 1,654 generator buses were used as a sink point in an FTR trade.[94] The sale of FTRs across

[93] This could happen when balancing congestion is very negative, thus reducing the congestion charges to load significantly.

[94] Based on LEI's analysis of pricing node definition provided by PJM staff.

all possible node combinations, subject to constraint impact tests, ensures a very granular representation of future congestion. If PJM were to restrict FTR paths to those having a sink node with a non-generator bus, the transparency (and granularity) of the price information provided by FTR auctions would be reduced by over 87%.

Figure 27. How load is supplied in the day-ahead market in PJM

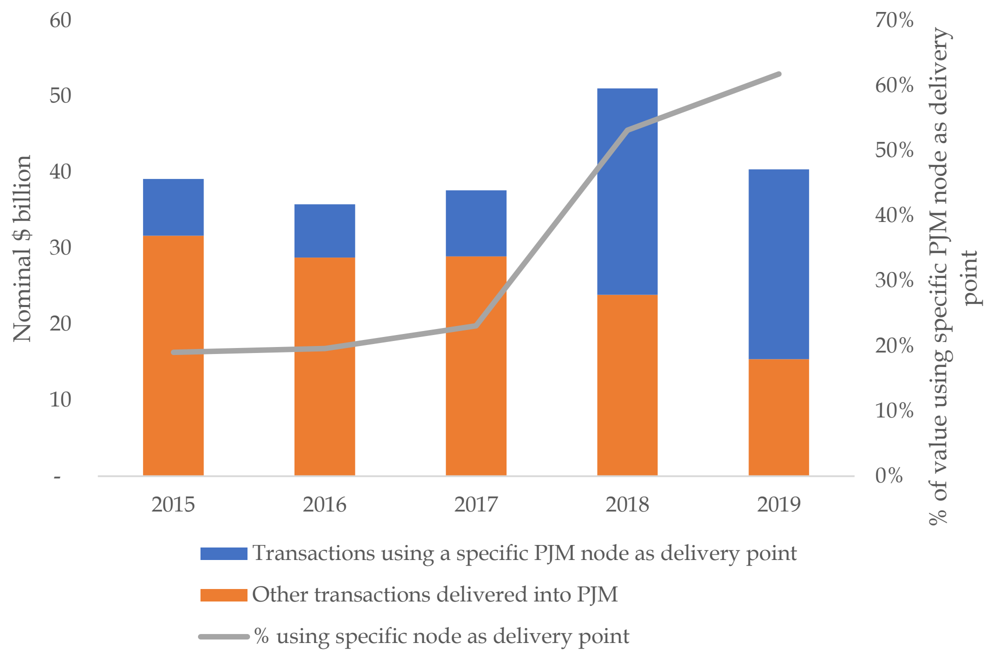


Source: PJM. Financial Transmission Rights Market Review. P. 3.

A point-to-point construct also allows a better match to bilateral contracting when delivered from a specific node or delivered to a specific node. Price signals at the generator bus are important because bilateral transactions follow a point-to-point construct as well. We know that over 75% of the load in PJM is being supplied by bilateral contracts or self-supply, as presented in Figure 27. Also, the value of bilaterally-negotiated energy contracts delivering to a *specific* node in PJM totaled $15 billion per year from 2015 to 2019 based on transaction data reported to FERC's EQR database, or over 35% of all transactions delivered in PJM. In 2018 and 2019, this value has increased to over $25 billion per year, or over 50% of transaction values, as presented in Figure 28. Therefore, market participants' ability to have more transparency about what level of congestion risk a generator or node would face has significant value to market participants.

One additional advantage of a path-based approach is the ability to grant IARRs to transmission developers that can precisely match the source and sink point of the transmission projects developed.

Figure 28. Energy transactions delivered into a specific PJM node reported to FERC EQR database



Source: LEI analysis of FERC EQR database.

Disadvantages

The disadvantage of a path-based construct is that it requires a network model to estimate the simultaneous feasibility of multiple paths to avoid over-selling network capacity and under-funding FTRs. Network modeling is needed because the same network constraint could impact FTR paths with different source and sink points, and over-selling FTR paths that are bound by the same constraint would mean PJM would not collect sufficient congestion charges from the day-ahead energy market to pay all the relevant FTR holders. Therefore, with the path-based construct, PJM conducts network modeling (and specifically SFTs) during the ARR allocation process and FTR auctions to prevent over-selling its network capacity.

A network model will require inputs and assumptions and will be a “projection” of transmission system use – realized transmission system use in the day-ahead energy market might differ. In choosing assumptions for the network model, PJM faces a choice between (a) being conservative and limiting how many FTRs can be cleared in an auction (and this approach would limit the total revenues collected from FTR auctions and paid out to ARRs, as well as result in having more surplus congestion to allocate), or (b) being aggressive and maximizing the quantity of FTRs cleared in the auction, but then creating a risk of inadequate funding of FTRs (which would be anticipated by FTR holders and reflected in their auction bids, negatively affecting the FTR auction revenues and ARR holder payouts). PJM has generally opted for the conservative approach, and since the market rule change that shifted the allocation of surplus congestion to load, the potential problem of an FTR auction providing too little revenue to load has mostly been resolved. However, under this conservative approach, the amount of surplus congestion that has to be allocated to load can be significant, and as discussed in Section 6.3 above, this raises equity issues between LSEs.

The IMM also identified insolvency risk associated with a path-based FTR construct.[95] The IMM believes that a path-based FTR design could result in losses larger than what an FTR holder paid for the FTR path.[96] Such a situation creates an underfunding risk to all FTR path holders in case a market participant defaults.[97] However, the underfunding of all FTR paths driven by negatively valued FTR paths only happens if the holder(s) of the negatively valued FTR paths default on their obligation to pay. As such, LEI views this specific disadvantage of a path-based construct as a credit-related issue outside the scope of this study. LEI understands that a separate PJM Task Force is addressing this topic.

In summary, LEI believes that the advantages of a point-to-point FTR construct (which is creating a granular price signal for the forward markets and facilitating bilateral transactions) outweigh the disadvantages of relying on an imperfect network model. Such disadvantages can be reduced through improved network modeling, and more importantly, modifications to the ARR mechanism to minimize surplus congestion, which we discuss in Section 8.3. Therefore, LEI recommends PJM to continue with the point-to-point FTR construct.

6.5 What are the advantages and disadvantages of a dual system of rights?

The current ARR/FTR mechanism is a system with a dual set of property rights. This means that ARRs and FTRs are distinct rights. They are not perfect substitutes,[98] and they may have different

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[95] PJM IMM. "ARR/FTR Market Design: Addressing Risk." June 25, 2019. <https://www.pjm.com/-/media/committees-groups/task-forces/frmstf/20190625/20190625-item-06-imm-arr-ftr-market-design-addressing-risk.ashx>

[96] In contrast, the IMM notes that its novel proposal would not result in any payments by the congestion right holder.

[97] In LEI's view, the underlying reason such risk exists is because PJM does not assign congestion charges collected on a path-by-path basis, but instead aggregates all congestion charges collected into one pool to fund FTR target allocations. If this pool is insufficient to cover all FTR target allocations, PJM uses excess FTR auction revenues (i.e., leftover auction revenues after paying ARR target allocations) to make up the difference. If there is still a deficit, FTR paths would be underfunded. In such a case, "all positive FTR target credits get a share of underfunding if any exists at the end of the planning period to create a PJM-wide uniform deficiency ratio (uplift charges and credits)." *See* PJM. "FTR Underfunding Review." October 18, 2019. <https://www.pjm.com/-/media/committees-groups/task-forces/frmstf/20191018/20191018-item-03-ftr-underfunding-review.ashx> If a market participant holds an FTR path that has a negative FTR target allocation (there are multiple scenarios where this could happen, including buying counterflow trades) and it defaults on its obligation, every FTR holder suffers from underfunding risk from this default, and ARR holders would have their potential surplus allocation reduced.

[98] This means an ARR can be converted into an FTR (and hence becomes a substitute to ARR), but an FTR cannot be converted to an ARR and therefore this substitute is not bi-directional.

valuations (even if they are for the same path) because of the relative difference in the ARR risk profile versus the FTR risk profile.[99]

To better understand this concept, one should first understand how ARRs are created and obtained and the difference between ARRs and FTRs. ARRs are created through the ARR allocation process, and ARRs are entitlements to load or firm transmission customers. The method of allocating ARR involves load or firm transmission customers nominating from a pre-selected set of ARR paths, based on a set of rules, subject to the SFT. Note that load does not automatically own a defined set of ARRs. Instead, during each annual ARR allocation process, load must nominate eligible ARR paths during the ARR allocation process.[100]

Once load is allocated an ARR path, this ARR path gives the ARR holder the following obligations, rights, and options:

1. The obligation to receive/pay FTR auction price times the MW of ARR allocation of FTRs in the same path (i.e., ARR target allocation);

2. The right to receive some allocation of surplus (if any exist) based on the pro-rata share of the ARR target allocation – this is a right (not an obligation) as this is always a positive value;[101] and

3. The option to self-schedule the ARR path into an FTR path – the ARR holder will be a price taker in the FTR auction, and although it acquires the same FTR path, it does not have to pay anything for the FTR because it already owns the auction revenue of that ARR path. Therefore, self-scheduling does not mean the ARR holder gave up the rights to (1) and (2) above. It just means the ARR holder uses the proceeds from (1) to purchase the FTR path while keeping the rights associated with (2).

In contrast, buying an FTR from the FTR auctions only provides the FTR holder the obligation to receive/pay the difference between the sink CLMP and source CLMP, multiplied by the MW awarded for the FTR path. Note that the risk between receiving and paying the CLMP difference is asymmetric. If FTRs are underfunded, FTR holders with net positive FTR target allocation will receive less than their target allocation. However, FTR holders with a net negative FTR target allocation will still be required to pay PJM the full target allocation amount to PJM.

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[99] There are other nuances in the actual settlement of ARRs vs. FTRs, such as daily rebalancing of ARRs based on actual load served while FTR MWs are a fixed quantity once purchased. However, those are details that are more related to the implementation of the product design instead of fundamental design issues. In this section, we focus on the design elements of the two products.

[100] For details on the current ARR/FTR mechanism, please refer to Appendix C (Section 11).

[101] In case there is ARR target allocation underfunding, FTR holders funds the underfunding through an uplift charge.

In summary, buying an FTR path from point A to point B has a different risk and return profile than holding the same ARR path from point A to point B. ARR holders have more optionality (i.e., can hold ARR or self-schedule); they have an additional revenue stream (surplus congestion allocation); and, they have higher seniority in getting payments (FTR auction revenues are also used to first fund the ARR target allocation, before funding the FTR target allocation).

One more significant distinction between ARRs and FTRs is that not all FTR paths are ARR paths, but all ARR paths can become an FTR path. As we have already discussed, under the current ARR allocation rule, load can only nominate ARR paths with a generator bus as a source node and load as a sink node in Stage 1A and 1B of the ARR allocation process.[102] But such limitations on biddable points do not exist in the FTR auctions. Therefore, the set of possible ARR paths is a subset of possible FTR paths.

In summary, the advantages of this dual property right construct include:

- recognition in the current settlement rules that gives load priority to congestion charges. This is achieved by assigning the right to surplus congestion to ARR holders. However, the load cannot buy or sell this surplus congestion allocation (so this will be a disadvantage, as well). In addition, the existing settlement rules specify that left-over congestion charges (if any), after ARR target allocation and FTR target allocation are fully funded, would go to load, thus enhancing the ARR/FTR mechanism's ability to meet Purpose #1;

- separating ARR and FTR provides PJM leeway in under-allocating ARRs or under-selling FTRs. As discussed in Section 6.3.2, the path-based FTR construct requires PJM to estimate the available network capacity to be allocated in the ARR allocation process and sold in the FTR auctions in advance of knowing precisely how network capacity will be used in the day-ahead energy market. Under-allocating ARRs / under-selling FTRs would reduce congestion charges returned to load, while over-allocating ARRs/over-selling FTRs would result in ARR and/or FTR target allocation underfunding, which reduces the value of FTRs and lowers the congestion charge returned to load. Having a dual property right and granting surplus allocation only to ARR holders but not FTR holders ensures in the case of ARR under-allocation (but where FTRs are fully funded) that any excess FTR auction revenue is returned to load, and the impact of under-allocating ARRs is mitigated (but this does not resolve the equity issue of surplus allocation between LSEs);

- the ARR construct offers load a right of first refusal to a list of generator-to-load paths, subject to the historical choice set (in Stage 1). If load has access to generator to load paths that match its bilateral portfolio, this allows load to create a zero-cost perfect hedge against congestion risk by self-scheduling the ARR; and

[102] In Stage 2, zones are opened up as valid source points.

- finally, the ARR construct provides load an opportunity to obtain a fixed revenue (or payment in case of negative value ARR target allocation) instead of an uncertain (variable) congestion credit/charge. Historically, the risk of having a negatively valued ARR is much lower than the risk of having a negatively valued FTR for the same path.[103]

The main disadvantage of the dual property right system is, similar to the disadvantages of the path-based construct above, the requirement of a network model to allow ex-ante trading of FTRs, which will always result in (some) under- or over-allocation of system capacity. At the same time, the initial allocation of ARRs using only historical gen-to-load paths has resulted in a lot more possible FTR paths in an FTR auction as compared to ARR paths. This means the difference between the amount of network capacity allocated (to ARR holders) versus sold (in FTR auctions) is significant[104] and that there are more FTR auction revenues than there is ARR target allocation, which further implies surplus is a common occurrence. Therefore, a deliberate and equitable allocation mechanism for those surpluses is necessary to improve the existing approach based on positive ARR target allocations.

In conclusion, the choice of a dual-property right system versus a single-property right system involves trade-offs:

1. a dual-property right system allows the load flexibility in how it chooses to recover congestion charges – it can set up the perfect hedge for bilateral contracts through self-scheduling, or it can securitize the congestion charges in a fixed payment by holding the ARR and receiving then the annual FTR auctions revenues; however, the paths that load can choose for ARR allocation do not represent the full network capacity; and,

2. the dual system allows PJM to prioritize protecting rights of load over other market participants through allocation of surplus to load but creates potential equity issues when allocating the surpluses between different LSEs.

Overall, the dual property right system helps PJM to achieve the two main purposes of the ARR/FTR mechanism as a tradeoff because it can: (i) be offset by allowing load to access other ARR paths (further discussed in Section 8.3.3), and issues presented as tradeoff; and (ii) be mitigated with alternative allocation designs.

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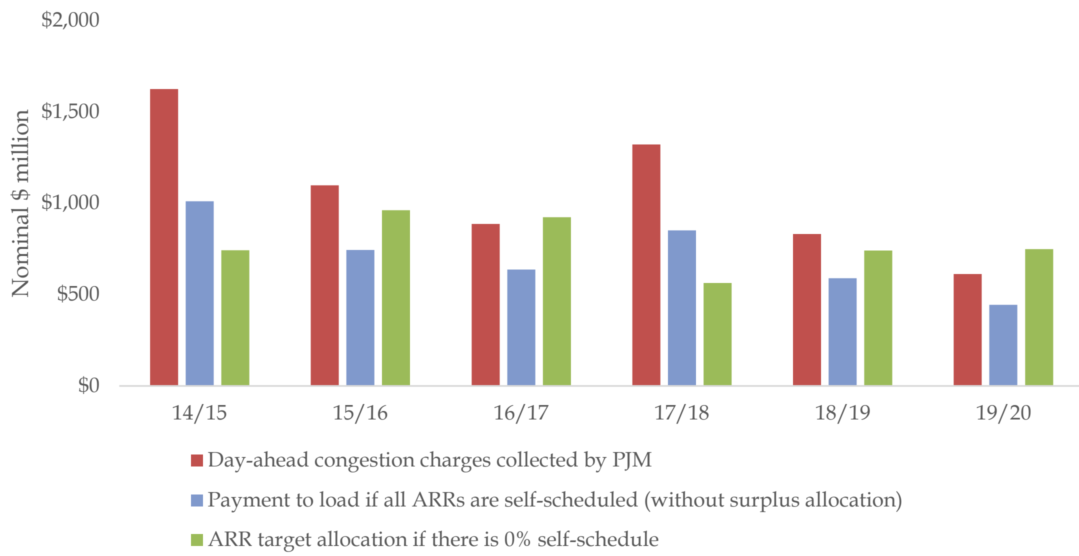
[103] Details available in Appendix E (Section 13).

[104] This is further discussed in Appendix E (Section 13.5), where LEI examined the historical MW of ARR allocated as compared to net MW of FTR auctioned, as well as dollars transacted in FTR auctions versus dollars of total ARR target allocation. LEI recognizes that this is not a precise assessment of network capacity allocated to ARR holders versus FTR auctions, as FTR auctions includes counterflow trades and gen-to-gen transaction at nearby source and sink nodes that are not materially constrained by the actual network. However, alternative metrics that can more accurately measure the percentage of network capacity allocated to load during the ARR process are not readily available in an easy-to-interpret format.

6.6 What are the concerns with the initial ARR allocation?

As discussed in previous subsections, the initial ARR allocation does matter to the ARR/FTR mechanism's overall effectiveness, as some elements of ARRs are not tradable and wholly contingent on the initial ARR allocation.

Figure 29. Congestion returned to load if all ARRs are self-scheduled (before surplus allocation) or none of the ARRs self-scheduled



Source: LEI analysis based on data provided by PJM.

The current problems with ARR allocation can be grouped into two categories. First, the amount of ARR allocated to the load is not maximized. Figure 23 on page 60 demonstrates that the MW of ARRs allocated may not cover the baseload MW in some zones. An alternative way to measure whether the ARRs allocated to load are sufficient is by measuring how much load would have been received from FTR target allocations if all ARR holders self-schedule their ARRs into FTRs compared to the congestion charges PJM collected. If the derived "all self-schedule" FTR target allocation is materially lower than the congestion charges PJM collected, then there is significant network capacity PJM has not allocated through the ARR allocation process. Figure 29 presents the congestion charges returned to load if all load self-scheduled all ARRs in the past six planning periods (blue bars), and if no ARRs were self-scheduled (green bars).[105][106] The red bars in the

[105] The comparison is using day-ahead congestion charges because the self-scheduled ARR paths payments are based on the difference in DA CLMP between the source and sink nodes.

[106] The reason surpluses are not included in the figure is because the purpose of this analysis is to understand how much of the ARR allocation process under-allocated network capacity. Surplus allocation is an ex-post

figure represent day ahead congestion charges PJM collected. The red bars are higher than the blue bars, meaning that, on average, if all load self-scheduled their ARRs, they would have received only 68% of the day-ahead congestion charges PJM collected on average over these years.[107]

The second category of problems is that ARR paths available for load to nominate are not representative of how the load is being served, as the ARR paths are based on historical paths set over 15 years ago (and some cases, much further back in time). To understand how much supply and demand conditions have changed in PJM since its inception, we present two maps that compare the geographical distribution of generation units in the current PJM service and population (as a proxy of load) between 1997 and 2020.

A comparison of the 1997 and the 2020 maps shows that the location of generation units has changed significantly over the past 20 years (Figure 30 and Figure 31 on page 73). The number of gas-fired units has increased dramatically, and many wind units (located in western PJM predominantly) have also come online. The location where the population is concentrated has also shifted towards the northwest (Chicago area) and northeast (New Jersey). The overall impact of these geographical changes in demand and supply means historical source and sink nodes may no longer represent actual power flows today and relying on such historical paths to allocate ARRs results in a mismatch between congestion charges returned to load versus congestion charges load pays. In Section 8.3, we provide recommendations on enhancing the ARR allocation process to align ARRs better with the basic principles and original purposes.

In conclusion, there are two issues with the initial ARR allocation: (i) amount of network capacity allocated to load in the ARR allocation process not being maximized; and (ii) relevance of ARR paths available to load.

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mechanism to allow for PJM to reallocate excess funds collected specifically due to under-allocation. Therefore, adding surplus back into the analysis would render the analysis meaningless.

107 For completeness, LEI also calculated the congestion charges returned to load if all ARR holders keep their ARRs and did not self-schedule any ARR into FTRs, represented as the green bars in Figure 29. Note that in years with extreme weather, the blue bars are taller than the red bars, but this is not the case in normal weather years. This indicates the value of self-scheduling is a hedge of high congestion charges during extreme weather years.

Figure 30. Map of generation units and population in PJM area (1997)

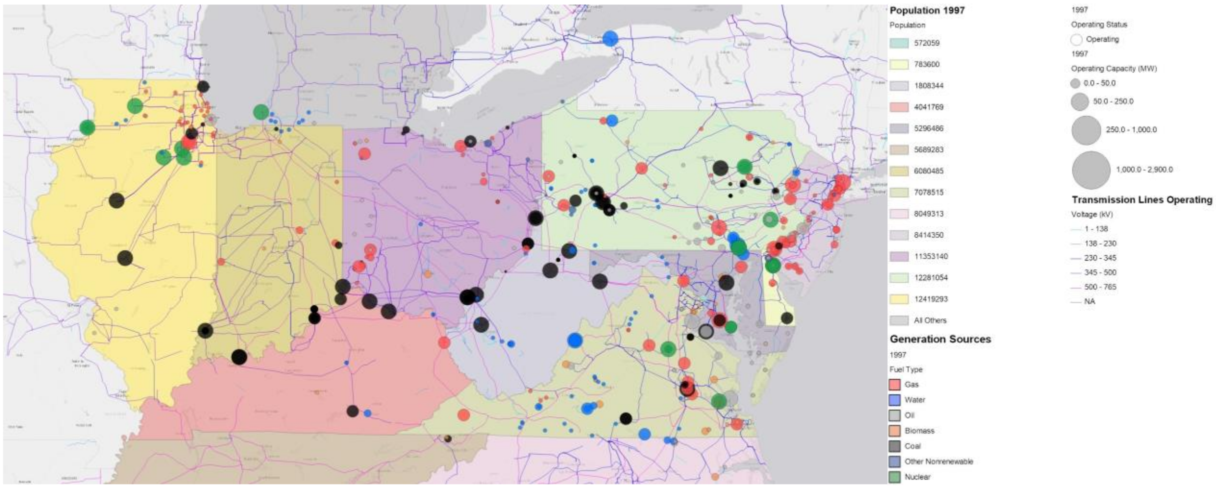
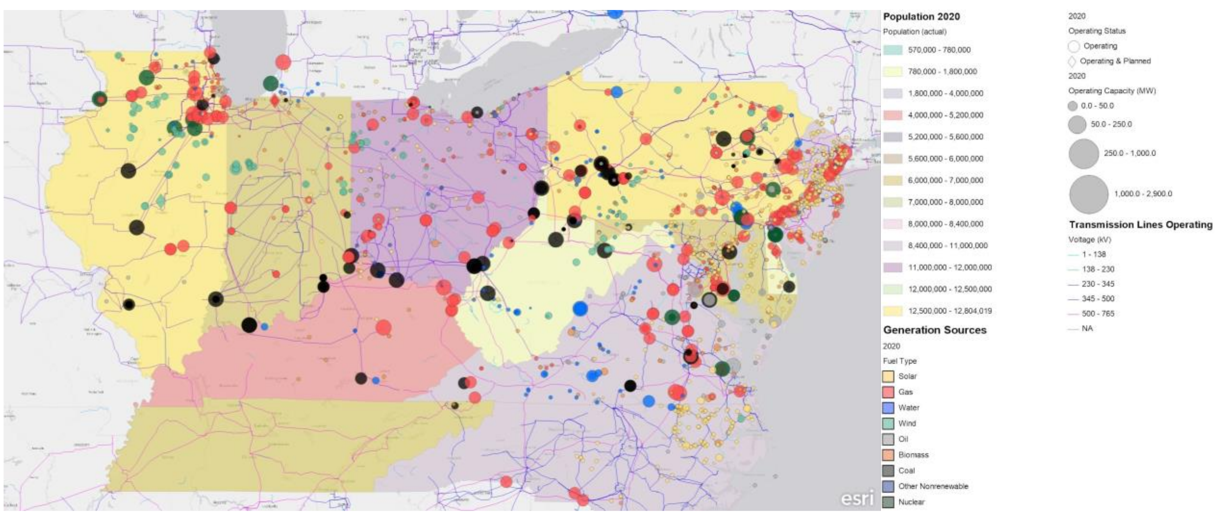


Figure 31. Map of generation units and population in PJM area (2020)



Note: Some of the PJM zones shown above in were not part of PJM in 1997.

Source: Third-party commercially available database.

6.7 Are the FTR auctions efficient?

A hallmark of an efficient auction is its ability to anticipate or predict the future value of the product. The ability of FTR auctions to predict congestion is important because it impacts whether other energy products, such as forward markets and bilateral contracts, can rely on price signals produced from FTR auctions. If FTR auctions have good predictive power for nodal congestion, then traders in forward markets and bilateral contracts can develop nodal price-based products and hedge their risk using FTRs, therefore increasing the liquidity and efficacy of the forward market.

From the load's perspective, the ARR/FTR mechanism has many similarities with insurance markets. If load decides to retain their allocated ARR, it effectively agrees to receive a fixed payment and, in return, gives up a variable revenue stream (which could be negative). If load has already entered into a fixed price bilateral contact with a generator, holding an ARR on the same path would allow the load to lock in the overall cost of supply. In contrast, if load owns a generation unit, self-scheduling the ARRs into the annual FTR auction on the same gen-to-load path would allow load to create a hedge against the congestion risk along that path.

Therefore, whether the FTR auctions have good predictive power of expected congestion affects the cost of hedging for load (and generators). This ultimately impacts the cost of electricity supply to end-users, which is explored further in Section 6.13.

To do this, we need to first assess the efficiency of FTR auctions and their predictive power over day-ahead congestion. LEI conducted a number of statistical analyses to test whether annual, monthly, and long-term FTR auctions can predict day-ahead congestions. The details of the results are presented in Appendix E (Section 13). The overall conclusion is that annual FTR auctions do have the ability to predict day-ahead congestion. In contrast, monthly FTR auctions have better predictive power for prompt-month congestion than annual auctions, except in months with extreme weather (generally in February). For long-term auctions, the predictive power decreases but is still statistically significant for most FTR products.

The argument that the FTR auction result influences forward markets is not a purely theoretical hypothesis, and the relationship between FTR auctions and forward markets is not simple. Although FTR auctions occur at concrete points in time, futures trading is occurring daily. Market participants can purchase and sell futures in addition to or in lieu of acquiring FTRs. There is a variety of business uses for futures, in addition to hedging basis differences (congestion risk). Moreover, the price discovery provided by FTR auctions is not strictly to predict precise CLMPs, but rather to inform on general market sentiment regarding congestion and expected energy flows. To understand how PJM FTR market activities influence the forward market, LEI worked with Nodal Exchange to examine trends in volumes of basis-related futures right after PJM FTR auction result are published. The data indicates that volumes of futures traded on Nodal Exchange increase significantly after each FTR auction. The results are summarized in Figure 32. The uptick in volumes indicates the presence of price discovery process and influence of FTR auctions over futures activity in PJM.

Figure 32. Increase in PJM futures volume following posting of the FTR auction results, 2017-2020

Trading Year	Following Annual Auction	Following LT Auction	Following BOPP Auction
2017	141%	45%	29%
2018	83%	111%	9%
2019	79%	35%	53%
2020	240%	41%	90%

Source: Analysis provided by Nodal Exchange.

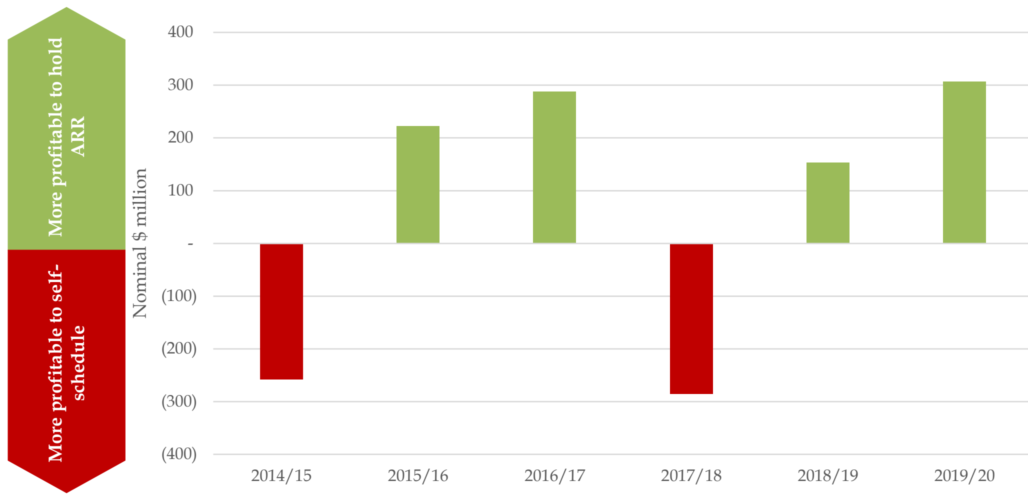
Notes: Calculations are volumes over five days after the posting of the auction results and exclude volumes from days following the annual New Jersey Statewide Basic Generation Service Electricity Supply auctions.

LEI also tested whether the participation of non-load entities in the FTR auctions improves FTR's predictive power of day-ahead congestions. LEI relied on a simulated auction results provided by PJM (as part of the PJM ARR/FTR White Paper analysis, PJM recreated FTR auction prices for planning period 2017/18 if no financial participants (i.e., non-load) traded FTRs). Comparison of the statistical properties of the simulated and actual auction results at predicting day-ahead congestion shows that the actual FTR auction, which includes both load and non-load participation, has a better predictive power of day-ahead congestion than the simulated auction results with "no financial participation." This indicates that non-load participation improves the price discovery feature of FTR auctions.

Given that FTR auctions have predictive power over day-ahead congestion, we can also examine whether such predictive power has resulted in reasonably efficient outcomes for ARR holders. LEI conducted two "what if" analyses on historical ARR/FTR outcomes to answer this question. First, LEI calculated how much ARR holders would have earned if all ARR holders self-scheduled their ARRs into FTRs. The purpose of this analysis is to understand the size of the congestion refund that load receives regardless of the FTR auction prices (similar to the blue bars in Figure 29). Then, LEI calculated how much ARR holders would have earned if none of the ARRs are self-scheduled. This means the congestion charges returned to load would be entirely based on FTR auction results (similar to the green bars in Figure 29). If the FTR auctions have been competitive, the FTR auction prices should be reasonable level such that, on average, the two cases should yield similar congestion charges returned to load. In other words, there should not be a strategy (holding ARRs or self-scheduling) that consistently provides higher payments. The result of the analysis is presented in Figure 33.

From the planning period 2014/15 to 2019/20, load would have been receiving more congestion charges if they held on to their ARRs. This implies that the FTR auction prices have been relatively effective in regard to Purpose #1 and not unreasonably low (otherwise, self-scheduling would be the more economic choice). Furthermore, the years where load would have received more congestion charges by self-scheduling are periods with anomalous weather conditions (2014/15 has the PJM highest winter peak on record, 2017/18 had the Bomb Cyclone event). This shows that FTRs are more likely to be underpriced when the congestion level is more volatile.

Figure 33. Whether holding ARR or self-scheduling would result in a higher payment to load



Source: LEI analysis based on data provided by PJM.

6.8 Is there value to having multiple types of auctions?

PJM's FTR annual auctions represent the majority of annual net auction revenues – over 85% in the last three planning years (see Figure 34). With over 6,000 nodes defined in each annual auction in the previous three years, annual auction results provide a very granular understanding of expected congestion costs for the forward markets. Based on the cross-sectional multivariate regression model[108] developed by LEI, a significant t-statistic for all variables (at a 95% confident level) and a significant F-Stat (above 2800) confirms not only the overall significance of the linear regression model but also the annual auction result's ability to predict actual CLMPs. Thus, the annual FTR auctions are an essential component of the FTR mechanism.

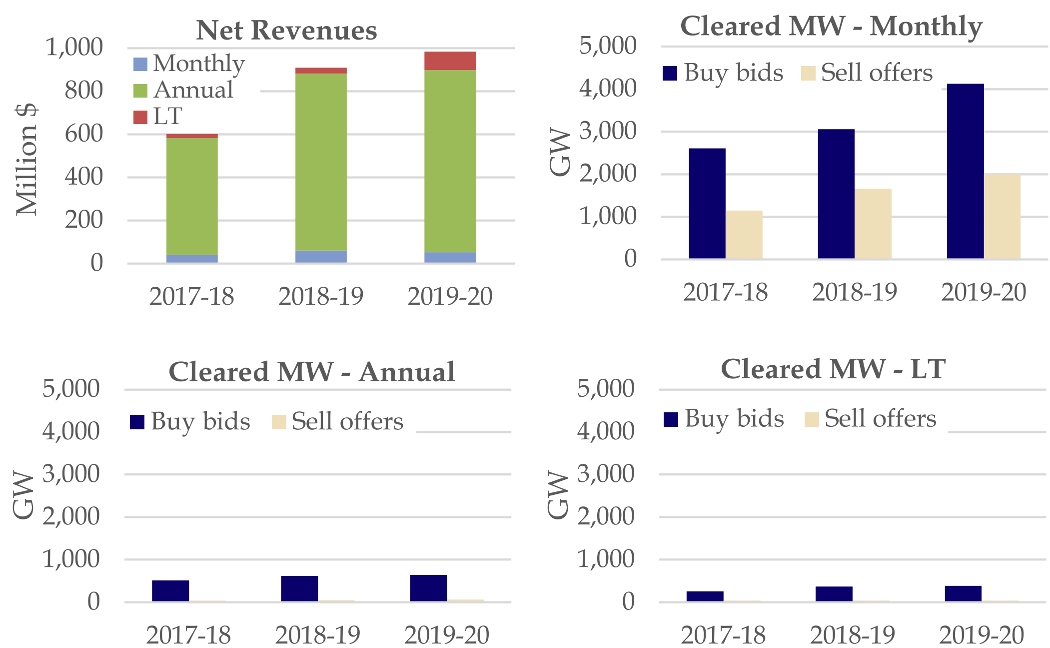
Monthly auctions produced the majority of cleared FTR products (in MW terms) for each planning period in the last three years, as illustrated in Figure 34. Monthly auction results were also very strong predictors of the day ahead CLMPs. These auctions give market participants, including LSEs, additional opportunities to refine their hedging portfolio (buy/sell FTRs). To ascertain if the monthly auctions provide price discovery, LEI tested regression models[109]

[108] Please see Appendix E, Section 13.1.

[109] Details of the analysis can be found in Appendix E (Section 13.1.5).

involving monthly FTR auctions' predictive power over monthly day-ahead CLMPs[110] for the 2018-2019 planning year. Figure 35 summarizes the results of the key regression statistics observed for each monthly model.

Figure 34. Net auction revenues and cleared MW by auction type



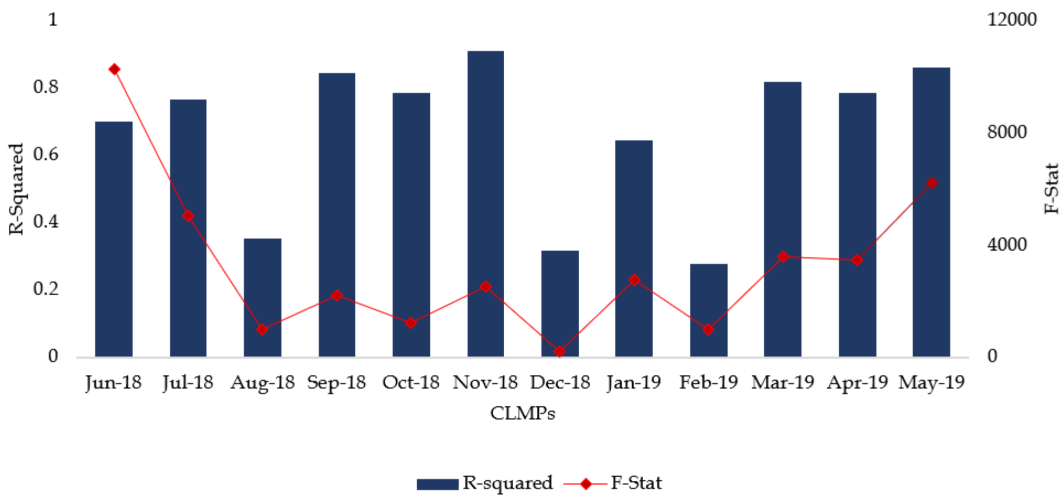
Source: LEI analysis based on PJM's FTR auction results. GreenHat transactions are included.

Note: Net revenues have been calculated as the sum of the dollar value of cleared buy bids subtracting the sum of the dollar value of cleared sell offers.

The R-squared on a scale of 0 to 1 represents the goodness-of-fit measure for linear regression models, and the t-statistic confirms the significance of each independent variable in the panel regression. Further, the F-stat confirms the overall significance of the regression model and the predictive ability of the independent variables (e.g., the FTR auction results). In the figure below, except for few months (such as Aug-18, Dec-18, and Feb-19), each monthly model was statistically significant, and monthly FTR auctions were observed to predict actual CLMPs on a cross-sectional basis. In light of these findings and the usage patterns of monthly auctions by market participants, LEI believes that monthly auctions are also an essential element of the overall FTR auction design and should be retained.

[110] Each set of monthly auction prices includes the settlement of the bids for the current month. These prices include the clearing prices for the month itself, the prompt month, and the month leading to the prompt month. However, due to the resetting of the PY in June each year, the rolling nature of the monthly auctions is limited, and therefore the months of June has one price and July has two prices.

Figure 35. Summary of regression results for monthly FTR Auctions, 2018-2019



Source: LEI Analysis, PJM.

In addition to annual and monthly FTR auctions, PJM also holds long-term FTR auctions. The long-term FTR auctions provide market participants with the ability to acquire a 3-year forward contracts for single year products. Five rounds of each auction are held in March, June, August, October, and December. To ascertain if the long-term auctions provide price discovery for the load, LEI undertook a cross-sectional regression analysis based on the long-term annual auction clearing prices[111] and the respective annual CLMPs for the various PJM nodes. The test results confirmed mostly significant t-statistics and significant F-Stats in the relationship between long-term FTR auction outcomes and realized CLMPs, which suggests that long-term FTR auctions contribute to price discovery. Although LEI has not performed any quantitative analysis to confirm this finding, some stakeholders noted that the addition of LT auctions improved the liquidity of PJM's forward markets. Casually, it can be observed that PJM is the only RTO with long-term auctions that have a duration longer than one year and PJM's bid-ask spreads and total volume of forwards exceeds other US RTOs. Moreover, LEI learned through the FGDs that market participants, including LSEs, use the LT FTR auctions to hedge congestion risk. For all these reasons, LEI believes that the LT FTR auction should be retained.

6.9 Are financial market participants over-earning in the FTR auctions?

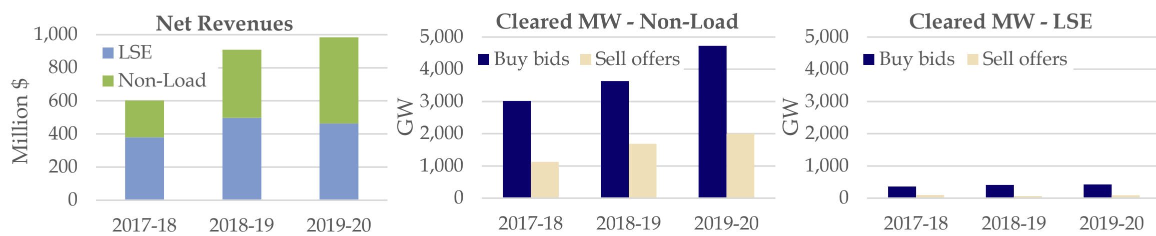
To answer this question, "financial market participants" must first be defined. Based on data provided by PJM, FTR market participants are classified into two categories: LSEs and financials. However, LEI views that this is an over-simplification as there are non-load market participants

[111] Note: Each set of long-term auction prices includes the settlement of the bids in the future. These clearing prices for auction rounds that are 36-months, 33-months, 30-months, 24-months, 21-months, 18-months, 12-months, and 6-months, trail the year of actual auction delivery.

that are not pure financial traders, such as generation companies or transmission developers. So, for clarity, LEI will be referring to "load" and "non-load" entities, to avoid any misunderstanding.

In the past three annual FTR auctions, non-load participants represent most of the transaction volume, but about half of the net revenues, as illustrated in Figure 36. Figure 37 presents the breakdown of net profits related to day-ahead congestion charges (FTR target allocation minus FTR auction proceeds) and surplus allocation earned by non-load entities in the FTR annual auctions from planning periods 2014/15 to 2019/20. On average, non-load entities earned a net profit of $247 million per annum.[112] This represents approximately 15% of all the dollars disbursed to all market participants through FTR credits, ARR credits, and surplus allocation. Some stakeholders refer to the net profit earned by non-load entities as "leakages," as these are congestion charges that are paid out to non-load entities, rather than LSEs.

Figure 36. Net auction revenues and cleared MW by market participant type



Source: LEI analysis based on PJM's FTR auction results. GreenHat transactions are included.

Note: Net revenues have been calculated as the sum of the dollar value of cleared buy bids subtracting the sum of the dollar value of cleared sell offers.

There are three sources of net profit for non-load when participating in the FTR market: profits from gen-to-gen paths (which accounts for 52% of the leakages),[113] profits from non-gen-to-gen paths (accounting for 38% of leakages),[114] and surplus allocation to FTR holders before the market rule change where the surplus is now assigned to load (this ceased with the 2018/19 planning period). If we recalculate the net profits and take out the surplus congestion that had previously been allocated to FTR holders, as per the current market rule, non-load entities would have earned a net profit of $223 million on average over these six planning periods, representing 13%

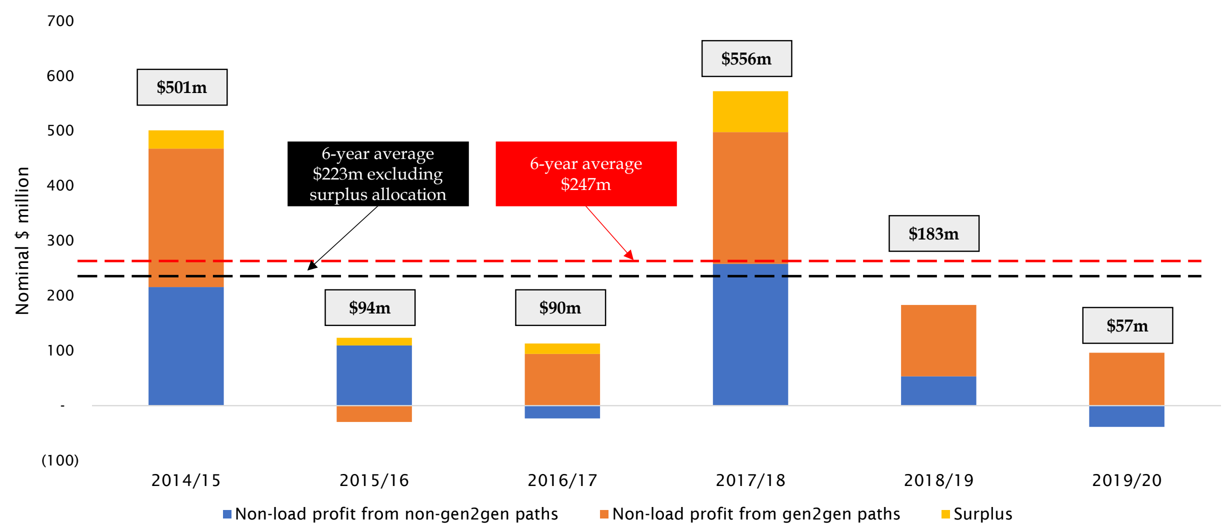
[112] This includes GreenHat transactions in 2018/19; LEI has not excluded those. If those transactions were removed, the net profit for non-load entities would be higher.

[113] Defined as any path that has both the source and sink nodes being generator buses. The node definitions are provided by PJM.

[114] Defined as any path that is not a gen-to-gen path.

of all the dollars disbursed to all market participants through FTR credits, ARR credits, and surplus allocation.[115]

Figure 37. Breakdown of the day ahead net profits made by non-load entities in FTR annual auctions



Note that this calculation is based on annual FTR target allocation and does not consider spot market transmission excess or derated capacities and does not take into account reduction in FTR target allocation due to forfeiture rules. In addition, for the 2018/19 planning year, LEI has not excluded the losses suffered as a result of the GreenHat default. The profit would have been $297 million instead of $183 million in that planning year if losses from GreenHat were excluded.

Source: Analysis of data provided by PJM.

The amount of net profit has been positive for the past six years, but it also varied. During years with more extreme weather conditions (2014/15 and 2017/18) have a much larger net profit is observed than other years. In those years, the profits from non-gen-to-gen paths make up a larger share of the net profit. In contrast, in years with normal weather conditions, the average net profit earned by non-load would only represent 7% of total dollars disbursed to all market participants through FTR credits, ARR credits, and surplus allocation.

Since the ARR/FTR mechanism design allows load to exchange a variable revenue stream for a fixed revenue stream, it should be expected that in some years, the counterparty assuming the variable revenue risk makes a net profit. This is similar to an insurance policy where, in this case, load is trying to shed the variable congestion charges risk, and some non-load market participants made a profit by taking on this risk and earning a premium. Also, as discussed further in Section

115 Details on the breakdown on the costs and net profits of different types of trades (gen-to-gen or non-gen-to-gen) done by different types of market participants (load or non-load) are available in Appendix E (Section 13.7).

6.10, on a more granular (path) basis, non-load entities have incurred losses and have faced material levels of risk in their individual FTR purchase decisions.

In summary, the average annual cost[116] to load associated with the current FTR construct is not a small number ($223 million a year, historically). However, the absolute size of the "leakage" is not demonstrative of whether load is harmed by the current design. Whether this amount of "leakage" is reasonable should be answered by analyzing the benefits provided by non-load participating in the FTR market, and whether the benefits outweigh the costs, which we discuss in further in Section 6.13.

6.10 Is non-load earning excessive profits through gen-to-gen paths?

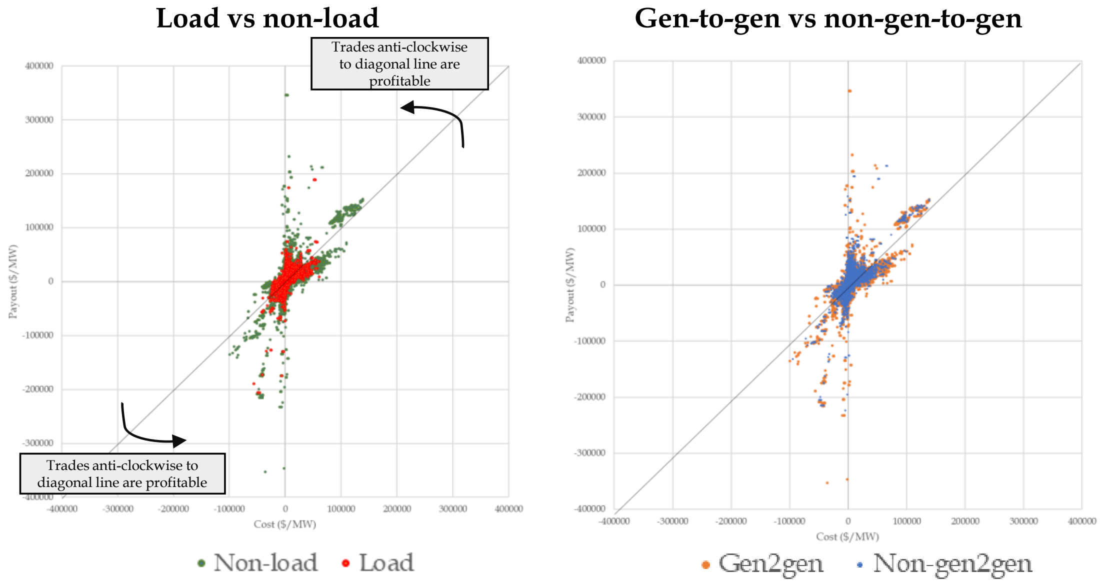
As presented in Section 6.8, non-load earns over 50% of its net profits from gen-to-gen paths. But gen-to-gen paths are not exclusively available to non-load. Load entities also participate in the FTR auctions and buy gen-to-gen paths. LEI examined the profitability of gen-to-gen paths based on type of FTR holder. Notably, between 2014/2015 and 2019/20, load entities on average lost $36 million in gen-to-gen trades. In 2015/16, load lost $268 million in one year on gen-to-gen trades (non-load also lost $29 million in gen-to-gen trades in that planning period). However, LEI does not view this as a reason to suggest gen-to-gen paths should be disallowed in the FTR auction. Instead, LEI views these statistics as demonstrative that (i) there is significant uncertainty (risk) in these FTR paths, and (ii) load is also an active participant in the gen-to-gen path product, which suggests that there may be an economic reason for them to trade such paths as they continue to trade such products even after heavy losses.

Figure 38 presents two charts with all the FTR transactions cleared in the 2018/19 annual FTR auctions. Both charts contain the same dataset, but the chart on the left is color-coded based on whether the trade is made by a load (in red) or a non-load entity (in green), while the chart on the right is color-coded based on whether the FTR trade is on a gen-to-gen path (in orange) or a non-gen-to-gen path (in blue).

The x-axis of the charts represents the cost of the trade-in $/MW. In contrast, the y-axis represents the trade's target allocation (i.e., the payout before adjusting for spot market network capacity changes). The cost of trades can be negative because there can be counterflow trades. For trades in the diagonal line's counterclockwise position, they are profitable, meaning the target allocation is greater than the cost. Trades located in a clockwise position of the diagonal line are unprofitable trades.

116 It is also commonly referred to by some market participants as "leakage." In this report, we use the terminology interchangeably.

Figure 38. Cost vs. profit of FTR trades in 2018/19



Note that these transactions include GreenHat transactions, which may reflect more non-load losses than in other years.

Source: LEI analysis of data provided by PJM.

By comparing the two charts, three findings emerge:

- The types of trades done by load versus non-load do not appear to be different—both load and non-load trade-in gen-to-gen and non-gen-to-gen paths.

- A cluster of non-load trades that load did not engage in had high cost but not very high returns. There is a cluster of green dots towards the top right that only non-load entities traded. Those trades are close to the diagonal line, reflecting the trades are profitable but not at a very high return rate. Similarly, there are some trades towards the lower left of the chart that have similar characteristics. It is not clear why load does not engage in those profitable trades. One possible reason is that these trades have high costs, and non-load entities are more capitalized to perform these trades. This also implies that non-load entities provide liquidity to the FTR market as they trade (and provide forward price discovery) on paths that would otherwise not be traded. We suggest that PJM continue to monitor profitability and competitive trends around such paths and any others that consistently result in big profit margins.

- There are trades with low cost, but a high or low payout, and both load and non-load engage in those trades, but non-load has a higher participation rate. In the charts, there are a number of trades that are located close to the y-axis but have very high or low payout values. These are mostly gen-to-gen trades that have a high-risk, high return profile.

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While both load and non-load have traded these paths, there are more non-load trades at the more extreme ends of the y-axis.

Overall, this analysis shows that non-load entities have been taking somewhat higher-risk, higher-return trades in the FTR market, and they have been able to profit from such activities. While gen-to-gen paths are the main source of such high-risk, high-return trades, select non-gen-to-gen paths also provide comparable (high risk/high return) trading opportunities. Similar to the observations of trading on gen-to-gen paths, load also participates in buying these other FTR paths, albeit on a smaller scale than non-load entities.

LEI recommends continuing to allow gen-to-gen paths to be trade. LEI also suggests enhancement that would allow load to choose gen-to-gen paths as part of the ARR allocation process. To complement these recommendations, it would be helpful for PJM to institute a more comprehensive monitoring program of the auction results at the path levels, to assess evidence of systematic excessive profits, or profits that are not commensurate with risk, and also track how highly profitable opportunities attract competition over time.

6.11 Are there FTR options that are sold at too low a price?

Options represent a small share of FTR products, in both net revenue terms and cleared quantities, as seen in Figure 39 below. LEI investigated typical purchasers of FTR options and profitability of those FTR options relative to FTR obligations. LEI identified some FTR options that traded at strictly \$0/MW price or at \$0 premium over FTR obligations on the same FTR path. This indicates a situation of FTR options' underpricing and suggests that PJM should set more stringent floor prices for FTR options. These findings are discussed below.

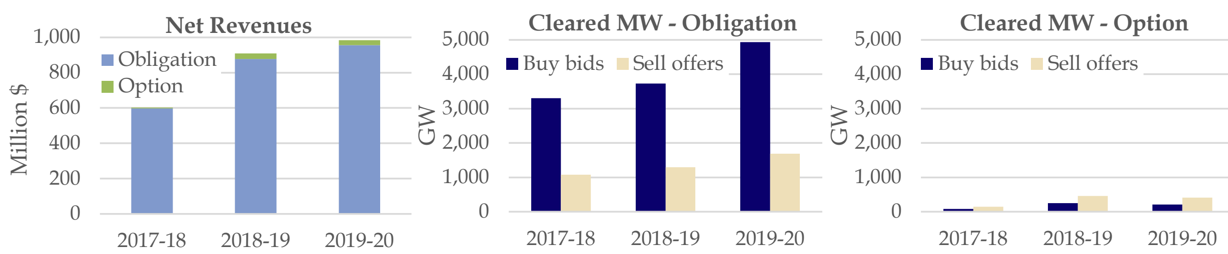
LEI reviewed options traded in the annual FTR auctions from 2014/15 to 2019/20 by identifying whether there are options that are sold at \$0/MW and whether there are options sold at the same \$/MW price as the obligation over the same FTR path.

Based on LEI's understanding from PJM staff, PJM's FTR auction clearing engine will not allow any FTR options to be cleared at below \$0 or the price of the same obligation path. However, it does allow for a clearing price at \$0 or the same price of the same obligation path.

We found that in total, there have been 896 MW of FTR options sold at \$0/MW in the past six planning periods (but none of them resulted in net profitable payoff), and there have been 10,179 MW of FTR options sold at no premium over the same FTR obligation path (referred to as "no premium" options). Over these planning periods, buyers of these "no premium" options received a \$7 million net profit.

By their nature, these FTR options are underpriced because the buyer of FTR options can only receive a positive target allocation. Therefore a \$0 FTR option effectively means risk-free profit. For FTR options priced at the same price as an obligation at the same path, this presents an arbitrage opportunity,[117] essentially providing risk-free profit to the arbitrager. In Section 8.6, LEI provides suggestions on how PJM's market-clearing engine can be enhanced to mitigate these "no premium" options.

Figure 39. Net auction revenues and cleared MW by FTR type



Source: LEI analysis based on PJM's FTR auction results. GreenHat transactions are included.

Note: Net revenues have been calculated as the sum of the dollar value of cleared buy bids subtracting the sum of the dollar value of cleared sell offers.

6.12 Does the LT FTR auction provide positive value to load?

As discussed earlier, the long-term FTR auctions at PJM aim to provide market participants the ability to acquire a 3-year forward contract, with auctions held each year in June, September, and December. As depicted earlier in Figure 34, the cleared volumes and net revenues from LT auction are not a significant portion of the FTR auctions, but not immaterial. From a net revenue perspective, in 2019-20, LT auctions produced 9% of total auction revenues that were returned to ARR holders. However, the more substantial benefit from LT auctions is in relation to price discovery and forward market liquidity. LEI has observed increased volumes traded on financial exchanges in various PJM futures a few days after LT auction results are released (see discussion in Section 6.7). Even though the LT auction clears up to three years in advance of day-ahead market outcomes, auction results have a statistically significant explanatory power over the day ahead CLMPs (see Section 6.8 for a summary).[118] LEI observed a correlation between the volume of cleared MWs (notably, the volume of cleared amounts is highest in round 3, as seen in Figure 40) and the statistical significance of particular round.

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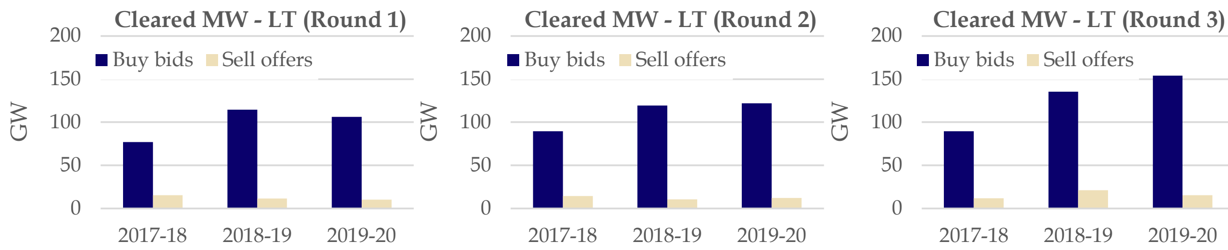
[117] If the buyer of the option can short the obligation path at the same time as buying the "no premium" option, it is paying $0 premium, but it can get a positive payout if the obligation results in a negative target allocation.

[118] Details of the analysis can be found in Appendix E (Section 13.1) of this report. Each set of models includes independent explanatory variables for different LT auctions (and rounds) for the same settlement period., including auction results from 36-months out, 33-months out, 30-months out, 24-months out, 21-months out, 18-months out, 12-months out, and 6-months out.

Figure 40. LT auction, FTR cleared volumes by round



Source: LEI analysis based on PJM's FTR auction results. GreenHat transactions are included.

6.13 Do the benefits of allowing financial players participating in the FTR auctions out-weigh the costs from the perspective of load?

Section 6.9 presented the "costs" to load of allowing non-load entities to participate in the FTR auctions – essentially, it is the net profit that these non-load entities are making from buying FTRs. These net profits are identified as a cost from the perspective of load because these profits reflect congestion charges that would have – but for the purchases made by non-load entities[119] - been distributed to load through the surplus allocation mechanism. To evaluate the significance of these "costs," we need to compare them against potential "benefits" to load.

6.13.1 Costs of non-load participation in the current design

"Costs" arise because of (a) actual congestion realized in the spot market and (b) the dynamics in the FTR auction. This is because the net profit paid to non-load entities is a function of the payment they receive (the "revenues" to FTR holders) and the payment they make to acquire the FTRs.

6.13.1.1 Extent of non-load participation does not affect the volume of congestion charges

The total congestion charges collected by PJM are solely a function of the spot market (day-ahead and real-time). The magnitude of the congestion charges collected through the spot market does not change regardless of whether non-load entities are participating in the FTR market. Therefore, non-load participation does not change the total congestion charges that are collected.

6.13.1.2 Non-load participants pay to acquire FTRs in the auction

Unlike load that is self-scheduling its ARR, a non-load participant must pay a "fee" to acquire an FTR (and therefore a commitment to receive/pay the congestion price spread associated with the specific FTR path in the future). That fee will be positive for (primary) flow FTRs or negative for counterflow FTRs (to take on the obligation to make future payments during settlement). Non-

[119] In the PJM ARR/FTR White Paper, PJM has already shown that there is also another effect to consider if these non-load entities had not participated – auction revenues (which dictate the payments to load that held onto the ARRs) – would have been lower too. We discuss this further in Section 6.13.2.

load participants must form an expectation about future congestion rents. There is uncertainty (risk) in the value of those congestion rents, and non-load participants willingly accept this risk, if they are able to earn a profit.[120] If market rules prevent non-load entities from earning a profit, they will exit the market and the benefits they provide to support efficient FTR auctions would cease. It is also important to recognize that non-load participants are competing against each other and load that is self-scheduling to acquire FTRs in the auctions (and the IMM has concluded that the market structure of the FTR auctions has been competitive[121]). Therefore, competition also tempers the profits earned. Ultimately, the prices paid by non-load entities to acquire FTRs in the auctions reflect expectations about future congestion, remuneration for the risks they are taking, as well as competition.

6.13.2 Benefits of non-load participation in auctions

Earlier this year, PJM examined the effect of non-load participation on FTR auction revenues using simulation techniques. PJM stated that "[i]n 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 Periods. The results showed a devaluation of roughly $329 million in 2018/2019 and $150 million in 2019/2020 without financial participation."[122] This is an important attribute of non-load participation, as such an outcome would mean reduced payments to ARR holders through a competitive, market-based mechanism, and a larger proportion of total congestion charges would need to be allocated through the surplus congestion mechanism. Furthermore, this analysis indicates that auction prices would become less efficient at reflecting expected congestion costs, and therefore undermine the price discovery that is critical for the forward markets.

6.13.2.1 Evidence of the connection between FTR auctions and forward markets

As presented in Section 6.7, using statistical analysis, LEI observed that the presence of non-load participants improves the predictive power of FTR auction prices on realized congestion costs in the day-ahead energy market. This tells us that the FTR auctions are a relatively efficient and good source of information for the forward market. We also observe a strong linkage between the FTR auction results in future market activity. Based on the data and analysis provided by Nodal Exchange and ICE,[123] futures volumes increase materially after the posting of auction results (the

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[120] The Keynes-Hicks 'risk transfer' hypothesis explains that the desire to reduce risk drives firms to hedge, speculative traders ensure that need is fulfilled. In analogy to the Keynes-Hicks hypothesis, financial participants (non-load entities) provide a beneficial service to load in the FTR auctions by taking on risks that load entities are currently not prepared to take on.

[121] Monitoring Analytics. "2019 State of the Market Report." March 12, 2020. p. 613.

[122] PJM. "Financial Transmission Rights Market Review" April 2020. pp. 19-20.

[123] Nodal Exchange. "FTR Auction Impact on Futures Trading and Prices." December 4, 2020.

increase in volumes traded is as much as 240% in the five business days following annual auctions, 90% increase in volume of transactions on average following posting of monthly auction results and approximately a 40% increase in volumes after LT auction results are posted. As discussed in Section 6.4, bilateral market activity frequently uses nodal delivery points and naturally benefits from the information on expected congestion that is released through FTR auctions.

6.13.2.2 Context for considering liquidity of PJM's forward market

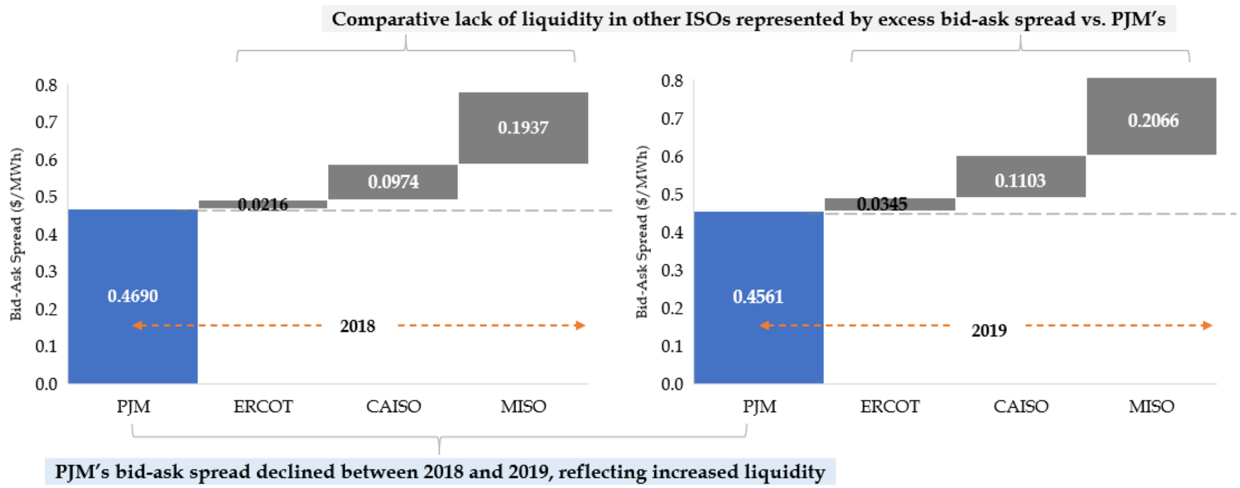
> *"Low levels of market liquidity translate into wider spread between bid and offer prices. The market participants who want to transact have to compensate their counterparties for increased risk … a higher bid-offer spread is compensation for taking this risk."*
>
> - J.P. Morgan Center for Commodities

A market is considered liquid if a large number of market participants trade in large quantities efficiently, without incurring large transaction costs and without materially moving prices. The churn rate is a measure of liquidity and is based on the volumes traded in the futures market relative to the throughput on the transmission system or total annual consumption. A higher churn rate generally suggests greater liquidity and competition in the forward market. PJM's forward market's relatively higher liquidity is reflected in its churn rate of 2.88x in 2019 (the highest among all the RTO-administered power markets) as shown in Figure 48 on page 99.

Another indicator to measure the magnitude of transaction costs incurred in engaging in forward market activity is the bid-ask spread, which is the difference between the lowest price for which a seller is willing to sell a megawatt-hour of electricity (i.e., ask) and the highest price that a buyer is willing to pay for it (i.e., bid). In Figure 41, PJM's liquid markets averaged a bid-ask spread of $0.46/MWh for 2018 and 2019. In comparison, other US RTOs/ISOs had a higher average bid-ask spread ranging between $0.49/MWh and $0.66/MWh, reflecting lower liquidity. This lower liquidity translates into a higher transaction cost for participants in the forward markets, ultimately impacting the overall cost of supply.[124] Further, between 2018 and 2019, PJM's average bid-ask spread declined slightly while other ISOs experienced an uptick in their respective bid-ask spreads.

[124] J.P. Morgan Center for Commodities at the University of Colorado Denver Business School. "Liquidity Issues in the U.S. Natural Gas Market." September 2019. p. 56.

Figure 41. Futures Bid-Ask spreads across ISOs in 2018 - 2019



Source: OTC Global Holdings/SNL, LEI analysis.

Liquidity makes the forward market more efficient. This, in turn, supports hedging and lowers transaction costs for both bilateral physical transactions and financial transactions in the forward market.

6.13.2.3 Evaluating long term benefits to PJM load

LEI explored the magnitude of long-term benefits to load by assessing benefits arising from hedging activity and transaction cost costs:

- A liquid forward market, facilitated by price discovery emanating from the FTR auctions, provides investors with an opportunity to effectively hedge the volatile spot market. Hedges reduce the perceived risk of a new generation development and thereby lower the cost of debt for financing such resources, which will ultimately reduce the long-run cost of supply to the benefit of all load in PJM. Electricity retail providers can also take advantage of forward markets to deploy hedging strategies to reduce, even eliminate, wholesale price risk. This can reduce the cost of capital for retailers, allowing them to expand their offering and potentially pass on cost savings to the final customers. Although it is difficult to measure this benefit precisely, we know it could be significant given that over 40% of PJM's historical load (315 TWh) was served by a competitive retailer in 2019.[125]

[125] In 2019, 315 TWh of energy (out of a total of 772 TWh total consumption) was served by competitive (non-incumbent utility) retail providers across PJM states, based on 2019 reported sales data. Source: EIA. "Electric Sales, Revenue, and Average Price." October 6, 2020. https://www.eia.gov/electricity/sales_revenue_price/

- Liquidity in the forward market will also impact transaction costs. Forward markets participant trading in PJM product enjoy one of the lowest bid-ask spreads in US power markets. Every $0.10/MWh in bid-ask spread raises transaction costs for physical and financial forward transactions by approximately $424 million in PJM (based on the current size of the physical market and futures market). Therefore, retaining a liquid forward market in PJM, with the support of price discovery provided by efficient FTR auctions, will benefit load in the long run.

We describe the magnitude of each of these benefits, based on illustrative analysis specific to the PJM market, in the sub-sections below.

6.13.2.3.1 Hedging benefits

Twenty new gas-fired CCGT projects were brought online with a commercial operating date between January 1, 2017 and January 1, 2020, presented in Figure 42. Based on LEI's research, twelve of these projects, highlighted with a star, employed financial hedges as part of their financing arrangements, including revenue puts, heat rate call options, and gas netback contracts. Financial hedges reduced the projects' market price exposure for some period, facilitating a lower cost of debt as indicated by S&P Ratings and Moody's. PJM's latest CONE analysis accepted by FERC[126] identifies the cost of debt for new CCGT as 6%, based on debt ratings of B to BB. Credit rating agencies assess the stability or volatility of a project's revenue stream by considering the degree of contractual support underlying the revenues and the sources of revenues. For example, S&P Ratings states that "a plant that has no contracts with off-takers or hedges could be assessed as having high market exposure."[127] In this way, the ability to enter into financial hedges directly translates into the cost of debt reduction for generation projects. Conservatively, LEI assumed that hedging wholesale price risk could improve the credit rating of a project and reduce the cost of debt by 0.39% to 0.78%.[128] In turn, this change in the cost of debt would translate into a

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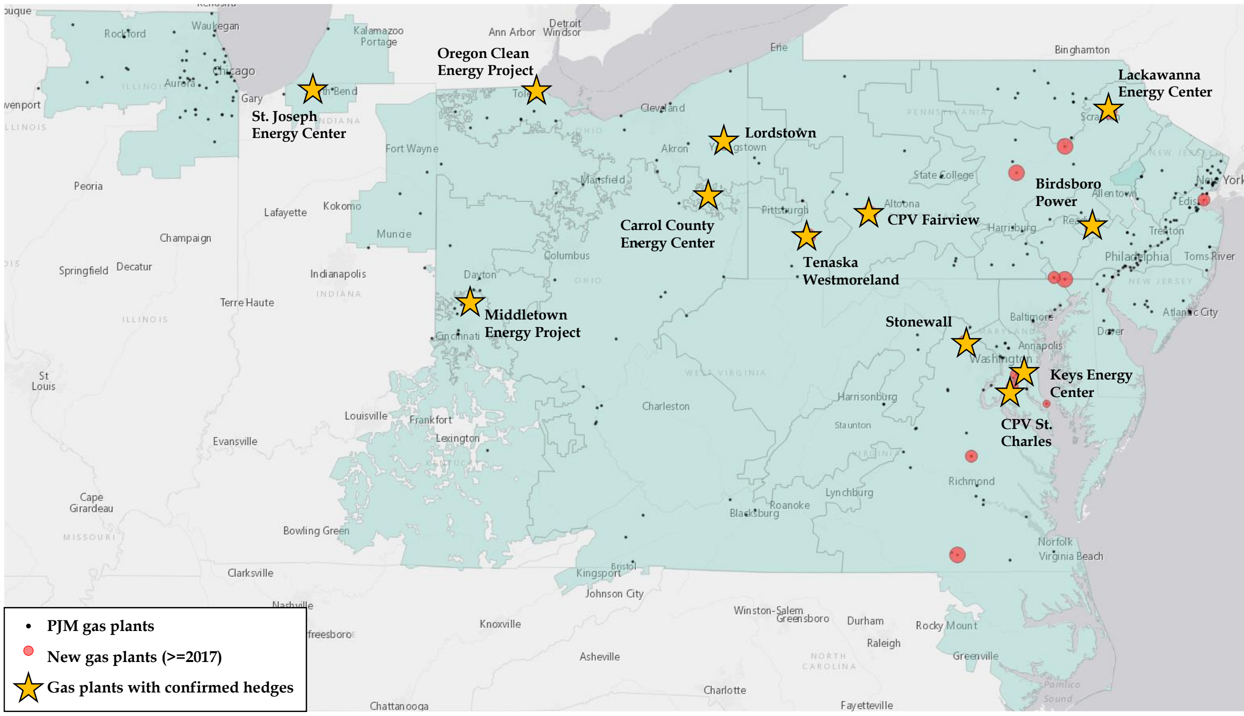
126 PJM. "PJM Interconnection, Docket No. ER19-105-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters." October 12, 2018.

127 S&P "Project Finance Operations Methodology." <https://www.standardandpoors.com/en_US/web/guest/article/-/view/sourceId/8687748>

128 If a project is unable to obtain a financial hedge, creditors of the project would demand a higher return to compensate for the higher risk of the project. In the PJM cost of new entry filing (October 12, 2018), the cost of debt is set based on the range of B-rated and BB-rated debt. LEI analyzed the credit spread in US high yield bonds with B-rated and BB-rated debt over three years (2017-2019). It is reasonable to assume projects that cannot obtain financial hedges would be on the lower end of the spectrum. Therefore, LEI tested a quarter-notch and a half-notch increase in spread from B-rated debt to conservatively reflect the impact of hedging. A quarter-notch improvement in credit rating would be equal to 0.39% decrease in the cost of debt, while a half-notch improvement in credit rating would be equal to 0.78% decrease in the cost of debt.

reduction in overall long-run marginal costs ("LRMC") of $0.26/MWh to $0.51/MWh for a typical new CCGT.[129]

Figure 42. Location of gas plants with confirmed hedges denoted with a star



Note: Stars represent new gas plants with a commercial online date between 2017 and 2019 with financial hedges. Red circles represent existing gas plants.

Source: LEI analysis and third-party database provider.

In 2019, gas plants set prices in PJM's wholesale energy market, approximately 70% of the hours (specifically, 69.4%).[130] Assuming an overall market size consistent with 2019 electricity consumption (772 TWh), and further considering the combination of the lower debt savings and that new CCGTs would directly or indirectly affect market prices in 50% of the hours, the benefit of a lower LRMC would be $99 million per year. If the frequency with which CCGTs affect overall

[129] This calculation is explained further in Appendix E (Section 13.9.1). LEI recognizes that the cost of debt and other financing components of the CONE estimate are prepared for purposes of analyzing offers in the capacity market. However, CCGTs have historically recovered some of their fixed costs in PJM's energy market. Moreover, for the purposes of this longer-term analysis, a LRMC estimate is more appropriate. A LRMC figure should be compared against an all-in market price, which makes it difficult to isolate day-ahead energy market revenues versus capacity-market revenue streams. Therefore, LEI intentionally focused on an overall market price per unit of energy consumed for this calculation.

[130] Monitoring Analytics. "State of the Market Report for PJM." March 12, 2020. p. 23.

market prices increases to 80%, the cost savings would be as much as $318 million a year.[131] Based on this example, the impact of lower LRMCs for new CCGTs is estimated to produce long-run benefits to PJM load ranging between $99 million and $318 million.[132]

Liquid forward markets also provide electricity retail providers with an opportunity to deploy hedging strategies to reduce, even eliminate, wholesale price risk. Retail customers generally prefer fixed prices over a period of time. On the other hand, wholesale spot prices change from hour to hour and can be very volatile in the short term due to demand fluctuations, generation availability, transmission system constraints, fuel costs, and weather conditions. As such, retail providers typically find themselves with fixed revenues but variable costs of supply. Forward markets provide a means for retail providers to hedge the wholesale cost of supply and reduce a major risk factor in their business operations. With a lower risk profile, competitive retails can reduce their cost of capital to improve their competitive position or re-deploy the released capital to innovate and expand their offerings to customers. Estimating the benefit of retail competition in PJM and the impacts of hedging on those estimated benefits was beyond the scope of this report. However, if the presence of liquid forward markets is responsible for even a small fraction of the benefits of retail competition, this is likely to be a multi-million-dollar benefit stream to load in PJM, given the extensive presence of retail competition in the region.

6.13.2.4 Evaluating the impact of transaction costs in the forward markets on long-run costs to load

Liquid forward markets also reduce the transaction costs for hedging and contracting bilaterally. As shown in Figure 41 on page 80, PJM's liquid markets averaged a bid-ask spread (2018-2019) of $0.46/MWh. In comparison, in 2019, other US RTOs/ISOs such as ERCOT, CAISO, and MISO had a higher average bid-ask spread ranging between $0.49/MWh and $0.66/MWh, reflecting lower liquidity. To analyze the impact of the increasing cost of losing liquidity, LEI developed a what-if (counterfactual) analysis based on the bid-ask spreads. PJM has experienced a standard deviation of $0.21/MWh to $0.22/MWh in its bid-ask spreads. Furthermore, we observe that PJM's average bid-ask spread in 2018-19 has been $0.19/MWh to $0.21/MWh lower than that of MISO and $0.10/MWh to $0.11/MWh lower than that of CAISO. We used a standard deviation of $0.21/MWh for our analysis, which also aligns with the average difference in bid-ask spreads between PJM and MISO, as the upper range of the potential benefits in reduced transaction costs enjoyed by PJM forward market participants. We also tested $0.10/MWh for the lower range, the observed average difference between the bid-ask spreads in PJM and CAISO. We then applied these potential increases in bid-ask spread by an estimate of total bilateral contracts and financial transactions in the forward market. We estimated this based on 2019 futures volumes and an estimate of bilateral activity (based on total electricity consumption less spot purchases and regulation generation (i.e., self-supply)). An increase of bid-ask spread range between

[131] It is very likely that as we see more the turnover in supply in PJM (i.e., retirement of coal-fired generation and new entry of renewables), efficient natural gas units will be price setting more frequently.

[132] Please see Appendix E (Section 13.9.1) for further details.

$0.10/MWh and $0.21/MWh would drive up transaction costs for forward market activity in PJM in the range of $424 million and $889 million a year.[133] Such transaction costs would ultimately have to be paid by load. Therefore, this is another indirect benefit of the price discovery and liquidity provided by the FTR construct.

6.13.2.5 Costs versus benefits

The long run benefits associated with liquid and efficient forward markets are additive in nature because the benefits connected to hedging (generation and retail supply) are distinct from the benefits related to transactional cost savings. While the illustrative numerical estimates of these benefits are not meant to be definitive, they show the relative magnitude of benefits that can be achieved with liquid forward markets, and therefore contextualize the importance of efficient FTR auctions that support PJM's forward markets. In summary, Figure 43 lists the indicative benefits of achieving Purpose #2 in the future versus the costs (foregone congestion charges) that load has historically ceded to non-load entities (and thereby reduced the payout to load that is part of Purpose #1).

The indicative benefits over the longer term outweigh the leakage (or costs) in the short term. Furthermore, recommendations made by LEI in Section 8, could result in a further reduction in the "leakage" if the enhancements to the ARR process motivates load to nominate additional paths in the ARR process and self-schedule those ARRs.

Figure 43. Indicative costs and benefits

Costs	$ million per year	Benefits	$ million per year
Profits of non-load participants (2014/15 to 2019/2020 average)	$ 223	Long-run marginal cost savings	$99 - 318
		Hedging and contracting transaction cost savings	$ 424 - $889
	$223		**$ 523 – $1,207**

6.14 Does the current ARR/FTR market design suffer from a lack of transparency or complexity?

As discussed in Section 6.14, simplicity enhances the goal of efficiency by lowering administrative burden and transaction costs, while transparency strengthens equitable outcomes as it allows

[133] Please see Appendix E (Section 13.9.2), for further details.

stakeholders to acknowledge reasonable results quickly or to challenge inequitable outcomes. To measure whether PJM's ARR/FTR market design is simple and transparent, LEI compared PJM's ARR/FTR process and features with the markets included in the case studies, namely CAISO, ERCOT, and MISO. The FGDs and questionnaire survey provided us with additional inputs on stakeholders' views on the market design's simplicity and transparency.

Compared to CAISO and ERCOT, PJM's ARR/FTR market design is more complex due to the dual property rights system and the sheer number of FTR paths. PJM's dual property rights system means a more complicated process compared to RTOs with single property rights. PJM has another layer of distributing transmission rights (ARRs). In contrast, in CAISO (where the rights are distributed directly) and ERCOT (auction revenues are allocated directly to load), the process is more straightforward. PJM has more FTR auctions (and rounds), which require participants to maneuver through a more complex system. PJM is the only RTO among the four markets that has a long-term auction. Also, it has more rounds in the annual auction (4 rounds vs. 1 and 3 rounds for CAISO/ERCOT, and MISO, respectively). Furthermore, while PJM has fewer FTR classes than CAISO and ERCOT, it has more biddable paths, which means more decision points for participants.

Nevertheless, there are also areas where PJM's market design is more straightforward. PJM's annual ARR allocation process is less burdensome to market participants as this is conducted once a year, whereas, in CAISO, the allocation of the CRRs is undertaken every month. Furthermore, PJM's annual ARR product is more straightforward than MISO's 8-product ARR choice set. More specifically, PJM has one ARR class (24-hour) compared to MISO's multiple ARR classes (peak/off-peak) and seasonal products (summer, fall, winter, and spring).

Figure 44. Simplicity and transparency in PJM relative to other ISOs/RTOs

Criteria	PJM features	Relative to other ISO/RTOs
Simplicity	• ARR process done once a year	⇧
	• Dual property system	⇩
	• Large number of paths	⇩
	• More FTR auctions	⇩
Transparency	• Data and information are available to all	▭
	• Data and information are released at the same time	▭
	• Timely release of auction results	⇧

⇧ **PJM is better** ⇩ **Others are better** ▭ **Same as others**

Regarding transparency, all relevant information on ARRs/FTRs is publicly available to all market participants in PJM and the other ISOs/RTOs. Data is also released at the same time on the PJM website and the FTR Center. The same set of information and data is also available to all market participants. This means that there is a level playing field for all participants of the ARR/FTR market.

LEI also determined that PJM releases some data and information slightly quicker than the other ISOs/RTOs. For instance, PJM posts auction results for each round earlier (within two business days) than the other RTOs (which release the results between 2 and 7 business days). Figure 44 shows a summary of our evaluation of the simplicity and transparency in PJM relative to the other ISOs/RTOs.

However, several stakeholders raised some concerns regarding transparency in terms of the changes made in the network model and the timely release of the network model. To address these concerns, LEI suggests some enhancements to improve transparency, as discussed in Section 8.8.

6.15 What are the IMM's views on the current ARR/FTR construct?

LEI also interviewed the IMM who had proposed (for multiple years) that PJM redesign the ARR/FTR construct and collapse the two property rights into a new system of "network congestion property right" whose value would be established based on PJM's collection of congestion payments after day ahead and real-time energy markets are settled.[134] The idea behind such a redesign is related to its dissatisfaction with the point-to-point architecture of the current FTR system and the belief that load and other firm transmission costumers were entitled to exactly 100% of total congestion payments collected in both the day-ahead and real-time energy markets.[135]

The IMM has raised a fundamental issue on the current ARR/FTR mechanisms, particularly on what is the primary objective of FTRs. The IMM believes that FTRs need to provide to load a 100% refund of congestion charges. The path-based dual system of property rights is not designed to meet this objective. The IMM, therefore, recommends that the current construct be replaced with a new design to remedy this concern. IMM's proposed network single property right will no longer have a point-to-point construct.[136] Instead, there will be a dynamic set of credits refunded to each LSE, based on the actual total congestion collected in both day-ahead and real-time energy markets. It is important to note that the network congestion property right's monetary value would only be known after the spot market has settled. Also, there is no specific

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[134] PJM Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM." November 12, 2020. p. 687.

[135] Ibid.

[136] There will be no "source" point, but although the sink is always the bus or load zone relevant for each LSE.

"source" point under this design, although the sink is always the bus or load zone relevant for each LSE. The IMM's network congestion property right would involve allocation of total congestion charges to LSEs based on observed binding constraints on the network in the spot market relative to the location of generation and location of load.[137] IMM's proposal allows – but does not require – that LSEs sell this new property right in advance of settlement of the day ahead energy market. Because there is no compulsory auction, not all LSEs may choose to sell their rights, and this may make it difficult to establish an efficient price and expectation of overall network congestion.

LEI understands that the IMM believes that its proposed allocation of congestion charges is more advantageous than the current path-based ARR/FTR approach because it will prevent over-or under- allocation of rights vis-à-vis actual network market solutions. Since there is no ARR allocation process, and therefore no need for network modeling - load will simply hold a right to receive a set of payments based on total spot market congestion charges.

Based on LEI's understanding of the proposal, the FTR concept proposed by the IMM is designed specifically (and solely) for Purpose #1. As such, LEI is concerned that the commercial activity might be disrupted and that there might be potential unintended longer-term consequences. Furthermore, as discussed in Appendix D (Section 12), most stakeholders do not support a complete overhaul of the ARR/FTR market; they prefer to see incremental improvements to the current system. Even those stakeholders that expressed interest in a new design stated that the new design would need to allow them to hedge congestion risk in the long-term. As such, investigation and prototyping of the IMM's proposal are necessary. For these reasons, LEI does not support moving forward with the IMM's network congestion property right proposal at this time.

[137] PJM IMM. "Constraint Based Congestion Calculations: Measuring Congestion Paid by Zone." June 22, 2020.

7 ARR/FTR mechanisms in other US power markets (Task 4)

Key takeaways

- There are numerous similarities between the three case study markets and PJM: all markets have an LMP-based spot market for energy, use a point-to-point construct with their FTR product, and have RTO/ISO-organized auctions for the FTR product.
- With respect to property rights assigned/allocated to load, there are major differences. CAISO and ERCOT use a single (FTR-only) system of rights; however, for various reasons, LEI does not believe that this design would improve outcomes for PJM's load and other firm transmission customers.
- ERCOT's direct allocation of auction revenues will not work effectively in PJM because of the different transmission rate design, the number of zones in PJM, and the complexity of bilateral agreements for load and generation in PJM.
- CAISO has recently reduced the paths that it sells in its CRR auction to improve the outcomes under Purpose #1. LEI has strong reservations about the applicability of such a change in the PJM context, as it could undermine the long run investment signal that is facilitated with auctioning of a more comprehensive set of FTR paths. CAISO also has a forfeiture rule, but it provides market participants with information and data relevant to adjust their behavior.
- On a high level, MISO appears to have a similar dual system of property rights (FTRs and ARRs) as PJM. However, MISO does offer more granular ARR products than PJM. MISO, notably, does not have a forfeiture rule like PJM, although it had experienced alleged market manipulation issues between virtual trading and FTRs in the past.
- Based on these case studies, LEI recommends that PJM evaluate offering more granular ARR products (peak, off-peak, and seasonal) and revisiting the forfeiture rule.

LEI conducted a case study analysis, reviewing the detailed history of FTRs (and, where relevant, ARRs) in other US power markets with LMP design. The purpose of this case study analysis was to identify differences among the RTOs/ISOs and to draw inferences as to whether alternative design choices could be applied in PJM's ARR/FTR design to benefit load. Each case study is discussed in detail in Appendix F (Section 14).

7.1 Markets selected for case study analysis

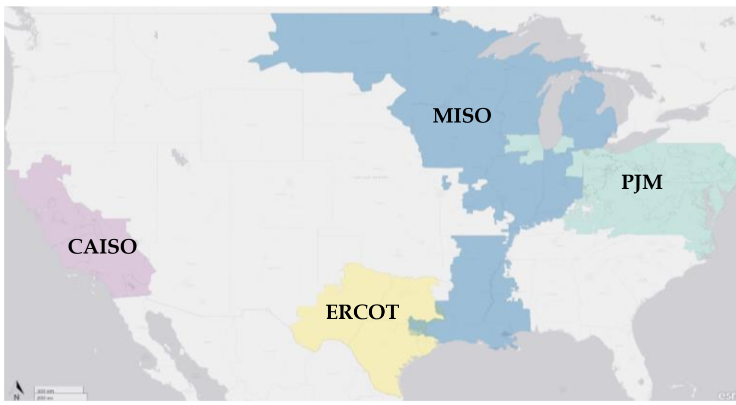
LEI chose to examine CAISO, ERCOT, and MISO because of the differences in the ARR/FTR design, and in the case of MISO, due to the high-level similarities in key circumstances:

- **CAISO** was chosen specifically because of recent changes in its FTR market (known as congestion revenue rights ("CRRs")). One of the recent changes that CAISO implemented involved reducing network capacity offered in the annual CRR allocation and auction process.

- **ERCOT** was included in the case studies because of its approach (single property right system) and direct allocation of auction revenues from the sale of CRRs.

- The third case study – **MISO** – was selected because of its high-level similarities to PJM. MISO has a dual system of property rights like PJM, a multi-state jurisdictional footprint, with zonal transmission rates, like PJM.

Figure 45. Map of RTOs/ISOs and key statistics covered in this Study



	CAISO	ERCOT	MISO	PJM
Installed capacity	79.8 GW	81.3 GW	197.6 GW	184.7 GW
Peak load	44.3 GW	74.8 GW	127 GW	148.2 GW
People served	30 million	26 million	~42 million	65 million
States covered	1	1	15 states + parts of Manitoba	13 states plus DC
Nomenclature	CRRs	CRRs	ARR/FTR	ARR/FTR
FTR/ CRR implementation	2006	2010	2005	1998
Day ahead congestion	$ 354 million (PY 2019/2020)	$813 million (CY 2019)	$ 528 million (CY 2019)	PY 613 million (PY 2019/2020)

Sources: State of the Market Reports of the ISOs/RTOs; ISO/RTO website.

All these markets have an LMP-based spot market for energy and use a point-to-point construct with their FTR product, like PJM. CAISO and ERCOT call their FTR-product "CRRs," as shown in Figure 45. The purposes of FTR (CRR) in MISO and ERCOT align with PJM's Purpose #2. More specifically, in ERCOT, the main purposes of the CRR were to support a liquid energy market by providing tradable financial instruments for the hedging of transmission congestion charges, to allow market participants to eliminate or greatly reduce the cost uncertainties resulting from transmission congestion charges, and to encourage competitive energy trading, where the costs of congestion might otherwise be an impediment."[138] In MISO, FTR's purpose is to "provide LSEs with a hedging mechanism against congestion charges collected in LMPs." [139] In terms of installed capacity, MISO and PJM are significantly larger than the other two ISOs. CAISO and ERCOT cover one state, whereas MISO and PJM encompass multiple states.

All three RTOs/ISOs introduced the FTR/ARR market when they first implemented the LMP design, similar to PJM. One difference between these ISOs/RTOs is how they provide a signal for generation investment. PJM, CAISO, and MISO have created standalone capacity products (in addition to energy). ERCOT has an energy-only market. Of the markets with capacity mechanisms, PJM has the highest proportion of states with unbundled generation. Although there are many independent generation owners in CAISO, the investment signal in California is motivated by Requests for Offers ("RFOs") issued by the regulated local electric distribution utilities and required as part of the integrated resource plans mandated by the California regulator.[140]

7.2 Comparative statistics

Of the markets analyzed, PJM enjoyed the highest FTR auction revenues in the most recent two planning years and experienced a significant increase between the PY 2017-18 and 2019-20, as shown in Figure 46. This trend in PJM's FTR auction revenues can be attributed to the rule changes and system conditions. ERCOT experienced an increase in auction revenues as a result of increasing network congestion.[141] MISO's auction revenues have contracted partially due to reduced congestion in the DAM resulting from network upgrades, improved processes, and the consequential reduction in the FTR offer prices.[142] CAISO, on the other hand, has seen a decrease in auction revenues due to the reforms it implemented (namely a reduction in the paths sold). It is interesting to note that although PJM has the highest FTR auction revenues, ERCOT has the highest FTR auction revenues per total energy consumption, as shown in Figure 47. This is consistent with the relative level of congestion in the DAM.

[138] ERCOT. "CRR - MUI User Handbook (Document Version: 2.10)," September 10, 2011. p. 6.

[139] MISO. "Initial Filling of Open Access Transmission and Energy Market Tariff" under Docket Number ER03-1118-000. July 25, 2003. p. 20.

[140] An RFO is a public request to buy, or sell a product through a structured process. The California Public Utility Commission oversees the amount and type of product solicited through the RFOs by the local EDCs.

[141] Potomac Economics. "2019 State of The Market Report." ERCOT. May 2020. p. 56.

[142] Based on LEI's conversation with MISO staff on November 24, 2020.

Figure 46. FTR auction revenues (nominal $ millions)

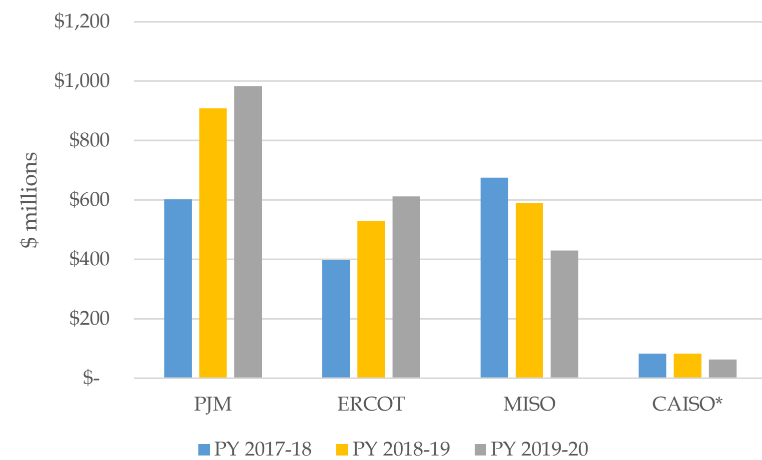
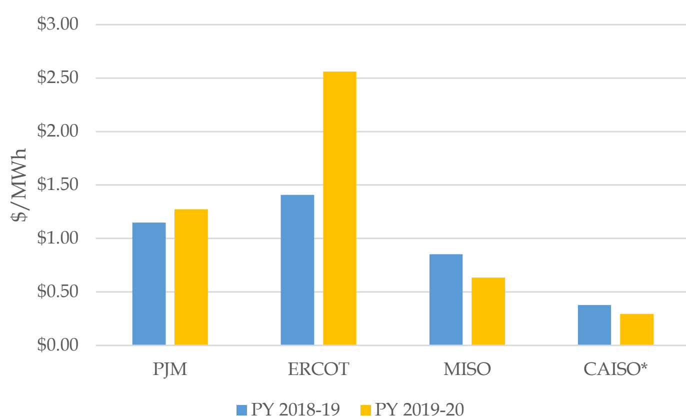


Figure 47. FTR auction revenues/total energy consumption (nominal $/MWh)



Sources: Potomac Economics. "2019 State of The Market Report. ERCOT." May 2020; Potomac Economics. "2018 State of The Market Report. ERCOT;" MISO. "FTR Market Results" Website; PJM. "Financial Transmission Rights." Website; CAISO. "CRR Market Analysis Report. Market Analysis and Forecasting."

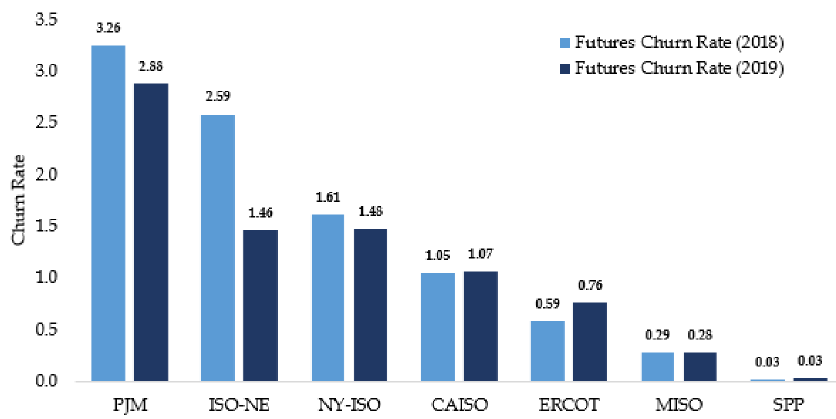
It is also interesting to examine the relationship between the FTR market size and financial forward markets. Based on data compiled from the ICE platform, PJM has the largest volume of financial futures transactions of any ISO/RTO with FTR markets in North America, as shown in Figure 48. LEI employed the concept of a "churn rate" to assess the relative difference in size. The churn rate captures the volumes traded in the futures market relative to the throughput on the transmission system or total annual consumption.[143] The churn rate is one of the analytical tools

[143] The futures traded (across hubs and contracts) are taken from data provided by ICE, while the total annual electricity consumption figure is reported by each RTO/ISO or the respective IMM.

used to measure forward markets' effectiveness and state of competition.[144] A higher churn rate generally suggests greater liquidity and competition in the forward market. The relatively higher liquidity of PJM's forward market is reflected in its churn rate of 2.88x in 2019 (the highest among all the RTO-administered power markets).

In addition to the churn rate, every futures trade reports the associated open interest, which is the number of outstanding FTR futures contracts held by market participants. As shown Figure 48, PJM had the highest open interest at $459 million in 2019.[145]

Figure 48. Estimated churn rate based on future volume traded on ICE across US power markets



			PJM	ISO-NE	NY-ISO	CAISO	ERCOT	MISO	SPP
Futures Traded	(2018)	(TWh)	2,579.23	308.30	260.00	230.79	220.37	198.02	6.67
Total Load	(2018)	(TWh)	791.09	119.16	161.13	220.46	376.24	692.18	259.65
Futures Traded	(2019)	(TWh)	2,223.50	228.09	231.33	228.96	291.56	188.96	8.03
Total Load	(2019)	(TWh)	771.93	155.85	155.85	214.96	383.85	677.41	258.63
Total Open Interest	(2019)	($ million)	459.40	61.66	65.07	48.99	43.10	53.75	2.44

Source: Intercontinental Exchange ("ICE"), LEI analysis.

7.3 Initial allocation of transmission rights (or the ARR allocation process)

There are significant differences in the property rights systems across the case study market and how they are allocated to load. ERCOT and CAISO have single property rights (CRRs), while MISO is the only one that has dual property rights (ARRs and FTRs), similar to PJM.

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[144] Oxford Institute of Energy Studies. "European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration." May 2017.

[145] The open interest for the futures traded for the ISOs were reported by ICE.

ARRs in MISO can be acquired through the annual ARR allocation process or a network upgrade, like PJM. Four types of entities are entitled to hold ARRs: (i) firm point-to-point customers, (ii) network integrated transmission service customers, (iii) grandfathered agreements, and (iv) multi-value projects ("MVPs"). This is similar to the qualifications in PJM to hold ARRs.[146] Like PJM, ARR holders in MISO have the option to hold onto the ARRs or self-schedule into the annual FTR auction ("convert" the ARRs to FTRs). MISO and PJM use a reference year for the initial allocation of the transmission rights. As the practice in PJM, MISO's qualified ARRs are defined based on generation to load paths. Although MISO and PJM have ARR obligations, the ARR classes offered are not the same. MISO provides peak, off-peak, and seasonal ARRs (summer, fall, winter, and spring), while PJM only offers 24-hour ARRs. PJM should explore giving load flexibility to nominate seasonal and time of use ARRs.

MISO's ARR allocation is conducted yearly and involves three (3) stages with a restoration stage between Stage 1A and Stage 1B. Like PJM, MISO has Stages 1A, 1B, and 2. However, unlike in PJM's system, ARR holders in MISO's Stage 1A can nominate up to 50% of peak usage.[147] In PJM's system, ARR holders cannot go beyond the baseload[148] in Stage 1A (and up to 50% of the qualifying transmission service reservation MW level for firm point-to-point customers). Based on data analysis, MISO's use of 50% of the peak load provides a somewhat higher amount of capacity than PJM's baseload definition. Stage 1B in both PJM's and MISO's systems are the same where ARR holders could nominate up to their peak load less the awards in previous stages. The processes in Stage 2 are not the same between PJM and MISO. MISO determines unallocated ARRs and assigns the right to receive excess FTR auction revenues in Stage 2 on the share of each market participant's unallocated ARRs over total unallocated ARRs, while PJM's Stage 2 involves three (3) rounds where the load can ask for ARRs from any generation, bus, hub, zone, or interface. In summary, MISO offers LSEs an opportunity for more flexibility in the ARR classes and a slightly higher volume of entitlements relative to the size of load in Stage 1A. In contrast, PJM offers more choice in Stage 2, albeit it locks in specific paths and quantities for the entire year.

CAISO and ERCOT do not have an equivalent to PJM's ARRs. CAISO allocates their version of the FTR product (CRRs), and then it is up to LSEs to sell the assigned CRR in the CRR auction or hold onto the CRR and receive the associated congestion charges from the day-ahead energy market. ERCOT directly allocates the auction revenues from the sale of CRRs to LSEs.[149] LSEs can still purchase CRRs in the auction, but they are not given for "free" to most LSEs.

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[146] PJM has the incremental ARR. This is discussed in Appendix C (Section 11.1.3).

[147] MISO's peak load is defined as the maximum load for the last 3 years.

[148] Baseload is defined as the minimum of daily peak loads for each transmission zone from previous year, inflated by one year's projected load growth.

[149] There is one exception. Non-opt in Entities ("NOIEs") are pre-allocated some CRRs in ERCOT at a discount, to reflect grandfathered arrangements that existed before the market opening. NOIEs consist of municipally owned utilities, electric cooperatives, and River Authorities. Typically, NOIEs either own a generation resource, or

7.4 FTR auctions

There are more similarities than differences in the FTR product and auction design across the three case study markets and PJM. For example, all four markets use path-based (point-to-point construct), and the FTR instrument is settled against day-ahead energy market congestion as measured by "CLMP" or equivalent between the source and sink points. All four RTOs/ISOs host auctions for the sale of FTRs (or equivalent product). The auction proceeds are refunded to load. The differences in the FTR mechanisms across the three case study markets and PJM relate to the details – like the FTR classes, and the number of rounds in the FTR auctions, as shown in Figure 49 below. Generally, PJM has the most rounds in its auctions and, with the exception of ERCOT off-peak classes, the most classes, and types of FTRs. And PJM is the only market to offer long-term auctions. Some stakeholders during the FGDs mentioned that this is one of the advantages of the PJM market.

FTR holders in both PJM and MISO can bid any path combination of generation, aggregate, hub, zone, interface, and load obligations. FTRs in both MISO's and PJM's systems are considered obligations, although there are selected paths in PJM that are also available as FTR options.[150] Like PJM, MISO allows for the gen-to-gen path; the only restriction is that the source and sink should not have the same bus. ERCOT has fewer biddable points than MISO and PJM; these biddable points comprise resource nodes (similar to generation), load zones, and hubs. FTRs include both obligations and options in ERCOT. CAISO has the most constraining set of paths offered to LSEs and market participants. Since 2019, to reverse the state of CRR revenue insufficiency, CAISO has limited the number of available paths through the CRR auction to only delivery paths (comprised of source and sink pairs associated with supply delivery to load). It is also interesting to note the impact of the changes in the CAISO CRR market. A year after the implementation of the CRR revenue sufficiency improvement process, CAISO's auction resulted in a contraction where the CRRs cleared at auction declined by 57% in 2019, and net auction revenues dropped to $63 million in 2019 compared to an average of $83 million in 2017 and 2018. As reported by the Department of Market Monitoring ("DMM"), CAISO's total volume of CRRs fell from approximately 792,000 MW to about 470,000 MW.[151] CAISO's experience raises the possibility of negative consequences of reducing FTR auctions paths.

have a long-term contractual agreement for annual capacity and energy from specific generation resources or have a long-term allocation from the Federal Government for annual capacity and energy produced at a federally-owned hydroelectric generation resource.

[150] Although considered in MISO's manual, FTR options are still not available to market participants. See MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.7. p. 140.

[151] CAISO. "2019 Annual Report on Market Issues and Performance." June 2020. p. 226.

Figure 49. Comparison of FTR (CRR) auctions

	CAISO	ERCOT	MISO	PJM
Auctions	• Annual • Monthly	• Annual • Monthly	• Annual • Monthly	• Annual • Monthly • Long-term
Annual auction # of rounds	• **1 round** per year after the annual allocation process	• **1 round**	• **3 rounds** of 8 independent auctions • Round 1: 1/3 of all capacity • Round 2: 50% of remaining • Round 3: All remaining	• 4 rounds (25% awarded in each round) • Awarded FTRs may be sold in later rounds
Annual auction products	• **Seasonal (or quarterly) CRR** obligation, peak and off peak	• **Peak weekday (5x16), peak weekend**, off-peak	• FTR obligations–peak, off-peak and **seasonal**	• FTR obligations/**options**–peak, off-peak, and **24-hr**
Monthly auction # of rounds	• Residual CRRs • 1 round every month after **monthly allocation process**	• 1 round every month	• Residual FTRs after annual • 1 round	• Residual FTRs after long-term and annual auction • 1 round
Monthly auction products	• **Monthly** CRR obligation, peak, and off peak	• Obligations/options • **Peak weekday (5x16), peak weekend (2 x 16),** off-peak (7 x 8), 24-hour	• Offers the possibility of one or multiple seasons/months, each of them allowing FTRs obligations for peak and off-peak	• FTR obligations and options for peak, off-peak, and 24-hour
Long-term auction # of rounds	• None	• None	• None	• **Five rounds where 20% of available FTR is awarded in each round**
Long-term auction product	• N/A	• N/A	• N/A	• **FTR obligations for peak, off-peak, and 24hrs** • **1-year term**

Note: In ERCOT, the annual auction is the long-term auction.

Lastly, it is important to note that there is no forfeiture rule in ERCOT and MISO. Indeed, MISO had a market manipulation event[152] with one market participant a few years ago but never instituted an automated forfeiture rule like PJM – opting for more active monitoring by the IMM. CAISO has a similar rule to PJM's FTR Forfeiture Rule (called the CRR Settlement Rule or Claw Back Rule). The CRR Settlement Rule triggers when the flow impact of a CRR's holder's entire virtual award portfolio exceeds 10% of the flow limit for each transmission constraint. When this happens, the CAISO adjusts the CRR revenues. The 10% threshold is the same as PJM. However, unlike PJM, CAISO does not have the $0.1 FTR Impact Test that PJM imposes and which several participants were concerned about. In addition, CAISO is different because it provides its participants with information such as (i) DFAX for each constraint that binds in the day-ahead and real-time market within three calendar days of the market day and (ii) transmission limits

[152] The FERC held a high-level investigation on the alleged FTR market manipulation by Louis Dreyfus Energy Services in 2014 due to its virtual supply and virtual demand trades, which artificially increased congestion around the Velca node in North Dakota from November 2009 to February 2010. FERC ordered LDES to pay MISO a fee of $3.34 million plus interest and pay a civil penalty of more than $4 million. See Appendix E (Section 14.3) for more information.

for all constraints in the day-ahead and real-time markets.[153] These are useful data and information for the participants to be able to monitor and modify their behavior.[154]

7.5 Key findings

While there are unique features in the three ISOs/RTOs' FTRs, not all of them would be relevant to PJM's construct. As is done in ERCOT, direct allocation of auction revenues will not work as effectively in PJM because of the number of zones and the complexity of bilateral agreements for load and generation in PJM. Also, the transmission rate design differs between these two markets; ERCOT uses a socialized transmission rate approach, while PJM utilizes a zonal transmission rate methodology.[155] While this approach works for ERCOT, it will not be "automatically" equitable for PJM to do away with ARRs and simply distribute FTR auction revenues on a pro-rata load basis, as zonal transmission revenue requirements vary. Therefore, this will result in different payment burdens for LSEs. Moreover, eliminating ARRs would take away a valuable property right for load, as discussed in Section 6.

Also, reducing the number of FTR paths, as was recently instituted in CAISO, is not likely to benefit PJM LSEs in the long run, as it impedes the achievement of Purpose #2, which is to support the forward markets. As discussed in greater detail in Appendix F (Section 14.1), CAISO has narrowly defined its CRR market design scope to exclude Purpose #2. Furthermore, as mentioned earlier, utilities in CAISO are not dependent on a market-based investment signal because of the integrated resource planning. A less liquid forward market can be compensated for using long-term contracts under the RFO process. Fewer paths would also mean reducing the FTR auctions' efficiency, which would undermine the use of ARRs, in addition to distorting the forward markets. Lastly, reducing the number of FTR paths would not be beneficial in PJM because low auction revenues would mean more congestion charges would be picked up in surplus congestion. The surplus congestion would then be allocated based on a system of pre-set rules rather than market valuations of the various ARR/FTR paths, which may not be as equitable or efficient.

Nevertheless, some elements from other RTOs/ISOs could be considered as potential enhancements. PJM can introduce more granular ARR products such as peak and off-peak and seasonal designations, as done in MISO. This may allow for more ARR allocation because of the various network model conditions that would be considered, specific to each time period and season. Furthermore, PJM should reevaluate the forfeiture rule to ensure that it does not deter

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153 XO Energy LLC . "Compliant of XO Energy vs. PJM Interconnection," April 8, 2020. p. 50.

154 Ibid.

155 Texas Public Utility Regulatory Act §35.004(d). <https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.192/21080adt.pdf>

market participants from conducting virtual transactions and is not indiscriminately punishing market participants that conduct legitimate hedging activities.

8 Recommendations for exploring changes to the current design (Task 5)

Key takeaways

- PJM and stakeholders should focus on improving the equity-related aspects of the current ARR/FTR design, while striving to preserve the efficiency-related features. Equity-related enhancements should focus on the ARR allocation process.
  - PJM should explore alternative ARR allocation processes in lieu of the current historical gen-to-load paths.
  - LSEs should be able to nominate other biddable points during the ARR allocation process and have additional flexibility in self-scheduling ARRs.
  - PJM should also consider introducing more granular ARR products (for example, sub-annual periods), and permit LSEs to self-schedule an ARR for a sub-period of the year (in the monthly or in the long term FTR auctions). These changes should improve the equity outcomes, especially between LSEs, as well as reduce the leakage.
- In respect of the FTR auctions, PJM should make only minimal changes.
  - The current set of auctions should be retained, as well as the full set of biddable points.
  - PJM should modify the rules for clearing FTR options, and revisit whether the FTR forfeiture rule is effective.
  - PJM should continue to monitor activities in the FTR auction and competition.
- Lastly, PJM could further enhance its documentation around the network model, including potentially a periodic independent review of the network model and key assumptions.

Based on our qualitative and quantitative analyses, LEI finds that the path-based, dual property rights system should be retained because it creates value to load and supports various commercial arrangements, as discussed in great detail in Section 6. LEI finds the current FTR auction design reasonable and generally achieving the intended purposes, and therefore, only minimal changes to that mechanism are necessary at this time. LEI's recommendations for enhancement are primarily focused on the ARR construct.

8.1 Path-based construct supports commercial arrangements and price discovery for forward

The original rationale for using a path-based construct remains valid. The current path-based construct should be retained, as the advantages outweigh disadvantages, as discussed in Section

6.4. Moving away from the current path-based construct may undermine achievement of Purpose #2.

8.2 Dual system of property rights benefits load and should be retained

The dual system of property rights currently used in the ARR/FTR mechanism should be retained as it creates significant value for load. We have outlined the advantages and disadvantages of the current design extensively in Section 6.5. Notably, some of the negative effects of the ARR/FTR construct can be lessened with reforms to the ARR allocation process. Therefore, LEI recommends PJM retain the current dual system of property rights in the ARR/FTR mechanism.

8.3 ARRs allocation process needs to evolve

The main issues related to the current ARR/FTR mechanism identified in Section 6 are related to inequity between LSEs when congestion charges are allocated to load, and the disconnect between ARR paths and FTR paths (which may have contributed to larger amounts of "leakage" historically). These issues can be addressed (and negative consequences for load diminished) by adjusting the ARR allocation process.

LEI has suggested a series of enhancements to address the main issues; the enhancements are inter-related and therefore should be considered as a "package" as much as possible. The recommended enhancements to the ARR allocation process include:

- finding common ground among PJM stakeholders on what is an equitable allocation of congestion charges between LSEs;
- examining in detail past settlements to track down sources of congestion charges;
- prioritizing increasing network capacity allocated to load in the ARR process, including allowing load to nominate outside-its-zone source points at earlier stages of the allocation process and allowing load to nominate non-traditional ARR paths; and,
- focusing on equity principles and actual system use when adjusting the ARR allocation process.

8.3.1 PJM and stakeholders should find common ground on what is an equitable allocation of congestion charges among LSEs

While one of the main purposes of the ARR/FTR mechanism is to return congestion charges collected by PJM back to load, a number of details regarding this purpose have not been clearly defined. The main unanswered question is equity: how to return congestion charges to load fairly and impartially? This is fundamental to Purpose #1 of the ARR/FTR mechanism because if congestion charges are returned to load in an unjust (or arbitrary) fashion, even if 100% of congestion charges are returned to load, the distribution of those congestion charges between LSEs may not be equitable.

There is some subjectivity in the definition of equity. Indeed, the concept of equity may be different, depending on whose perspective is taken. In the case of equitable distribution of congestion charges, the appropriate lens is that of load. LEI is not in a position to provide a recommendation of what is the "right" way to allocate congestion charges. It is up to PJM and its stakeholders to develop principles on equitable congestion charge allocations between LSEs. However, LEI can suggest a starting point for discussion and potential allocation principles for stakeholder consideration. For example,

- Given overpayment by load is related to LMP differences, it will be important for PJM to be able to identify who has paid congestion charges and how that relates to the use of the transmission system and congestion on the system. This information may be useful in developing alternative ARR allocation procedures.

- Furthermore, since load pays for the transmission network through regulated tariffs, surplus remaining after ARRs and FTRs are fully funded could be allocated to load based on pro-rata transmission revenue requirement paid.

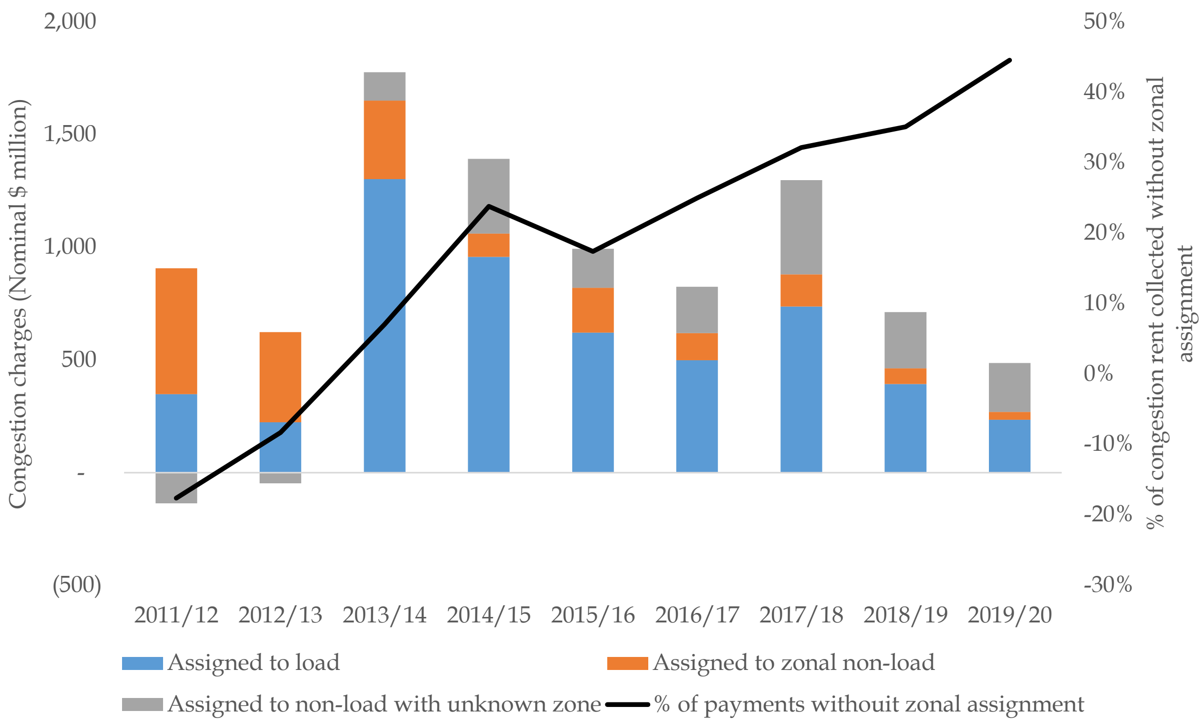
- Alternatively, in ERCOT, CRRs are allocated based on load share. In PJM, each transmission zone has a different transmission tariff and therefore contributes to the upkeep of the transmission system in a manner that is not strictly based on the size of its load. Therefore, allocation of ARRs on the basis of load shares would not be advisable. However, allocation of surplus congestion – if it arises due to greater overall use of the transmission network - could be allocated based on a simpler load share metric.

8.3.2 PJM should examine in detail past settlements to identify sources of congestion charges

One observation arising from LEI's analysis of congestion charges is that all market participants, including entities that only trade virtual transactions, have a CLMP component on their invoices. As such, both load and non-load customers have congestion credits or charges associated with their invoiced amounts. During this study's data collection phase, PJM provided LEI a zonal breakdown of congestion payments collected, grouped into a "load" and "non-load" classification. While all congestion payments collected by PJM assigned as "paid by load" had a zonal designation, the locational characteristic (zonal assignment) of the "paid by non-load" congestion payments were unspecified for a significant portion of congestion charges, as presented in Figure 50.

LEI recommends that PJM enhance its processing of the settlements to track the locational characteristics for congestion payments in more detail. This will allow easier application of equity principles around the distribution of congestion payments between LSEs and between load and non-load entities.

Figure 50. Day-ahead and balancing congestion collected by PJM with and without zonal assignment



Source: LEI analysis based on data provided by PJM staff.

8.3.3 Increasing network capacity allocated in ARRs should be a priority

In Section 6, LEI identified two main observations in the existing ARR/FTR mechanism that raised equity issues regarding the allocation of congestion charges between LSEs.

First, not all congestion charges collected by PJM have been returned to load. In fact, a significant portion of congestion charges are not allocated to load through the ARR allocation process and rely on other channels to be paid to load (such as surplus allocation). This is evidenced by the findings that even if all load self-scheduled their ARRs, load would have only received 72% of day-ahead congestion charges PJM collected in recent years (68% if we look back over six planning years, before PJM allocated ARRs less conservatively after the market rule change).

Second, surplus allocation does indeed contribute to a material share of congestion returned to load. In the past two planning periods (2018/19 and 2019/20), surplus allocation contributes 18% and 21% respectively of total congestion charges returned to load. This is an issue because surplus allocation is based on the pro-rata positive value ARR target allocation, and some LSEs may have been allocated more positive-valued ARRs than others because of the available ARR paths in their zone (therefore, they may get a larger share of the surplus congestion). This creates an equity issue between LSEs.

To improve the ARR/FTR mechanism's equity, LEI recommends increasing the nodes available to load to nominate during the ARR allocation process. This could be achieved by:

- allowing load to nominate outside-its-zone source points at earlier stages of the allocation process based on updated source-to-sink path menu (further discussed in the next sub-section); and,

- allowing load to nominate non-traditional ARR paths, such as gen-to-gen paths or gen-to-hub paths, or hub-to-hub paths.

Some may question the wisdom of this approach, and specifically why LEI is seeking to increase ARR paths (rather than reduce FTR paths). LEI's preference for allowing for more paths in the ARR process is based on expected efficiency benefits from leveraging market mechanisms instead of rules-based allocation method. Once load has been awarded a set of ARR paths, load has the ability to trade these ARRs in the FTR auction. Market mechanisms are more dynamic and adaptable to changes in market conditions, and results from the market-based allocation (i.e., FTR auction) will yield efficient price signals, supporting Purpose #2 of the ARR/FTR mechanism.

As concluded in Section 6, the current suite of FTR auctions appear to be functioning reasonably well. The auctions are efficient and there is a wide span of evidence that the auctions support forward market activity. Experience from CAISO shows that when the choice of FTR paths is reduced, FTR auction revenues may be negatively impacted - this is an undesired effect as it pushes more of the congestion charges into the surplus allocation process.

It should be emphasized again that regardless of how the ARR and FTR mechanisms are structured, the amount of congestion charges that PJM collects (and should distribute out to load) does not change. This size is purely driven by spot (day-ahead and real-time) energy market operations and network conditions. Reducing available FTR paths without increasing ARR path choices would only exacerbate equity issues among load as this approach increases the share of surplus to be allocated relative to congestion charges returned to load, or in other words, increases reliance on rule-based allocation. In contrast, increasing choice of ARR path may reduce leakages by allowing load to take greater risks (and therefore retain more of the net profits from the FTR auctions). It may also reduce the share of surplus allocated.

In summary, while increasing ARR path choices and reducing available FTR paths may both increase the share of total congestion returned to load, the first option achieves this by allowing more of the under-allocated network capacity, auction revenue, and congestion charges (these three items are inter-linked) to be distributed to load through market mechanisms. In contrast, the second option aims to achieve the same goal by reducing non-load's participation in the FTR market and therefore reduce the opportunity for profits. This may cause cascading problems in the forward market (loss of liquidity) and would increase reliance on the rules-based allocation of surplus to load.

8.3.4 Alternatives to allocating ARRs should be based on equity principles and actual system use as much as possible

In theory, self-scheduling ARRs would be the preferred option for load create a "perfect" hedge against congestion risk, if they were assigned an ARR that matches their bilateral contract.

However, we observe that over the past six years, only approximately 30% of the ARR capacity has been converted to FTRs through self-scheduling.[156] This implies that load has been more willing to take a fixed payment in exchange for foregoing rights to uncertain congestion charges in the day-ahead energy market, based on the ARRs allocated. Another implication is that historical gen-to-load paths allocated to load are not as relevant to LSEs (vis-a-vis its bilateral arrangements).

PJM should conduct a periodic review of actual system use to identify meaningful and relevant ARR paths for load. It is important that the ARR allocation mechanism allow LSEs to nominate paths that are aligned with their needs in earlier stages of the ARR nomination process. Alternatively, or in conjunction with this periodic review, load can also voluntarily provide bilateral contract information to PJM so that contractual arrangements are factored into the initial menu of ARR paths available to each LSE.

While it would not be sensible to force load to self-schedule the ARRs, we can expect load to self-schedule more of its ARR capacity, if the ARR paths are better aligned to actual energy flow and the bilateral contracts they are holding. An increase in self-scheduling, coupled with increasing the choice of ARR paths that load can nominate, would likely result in more network capacity being valued through the FTR auctions, and more of the congestion charges being returned to load would flow through the FTR target allocation instead of through ARR target allocation. The combined impact is less "leakage," and fewer congestion charges returned to load being distributed through surplus allocation.

8.4 ARR holders should have more flexibility in self-scheduling

As discussed in Section 8.3.4, the share of ARR paths that are self-scheduled is small. On top of the reasons related to the mismatch between current awarded ARR paths and actual system usage, another potential reason for observed low levels of self-scheduling is that the current self-scheduling opportunity is too restrictive.

Under the current market rule, ARR holders can only choose to self-schedule during the annual FTR auction, and for the most part they are limited to being a price taker in the FTR auction when they self-schedule. ARR holders have no option to only self-schedule for part of the planning period, nor can they effectively rationalize between the decision to hold onto an ARR or self-schedule (a limit order feature in the FTR auctions can address this concern).

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[156] More details presented in Appendix E (Section 13.5).

As our statistical analysis on annual and monthly FTR auction has shown, monthly FTR auctions may have better predictive power on prompt month congestion than annual auctions. At the same time, the level of congestion (and uncertainty on the level of congestion) differs by month. The same applies for on-peak and off-peak time periods.[157] Since the risk appetite of load in taking a fixed or variable congestion charge is not necessarily binary, some load may want to only hedge their congestion risk in specific months or time periods through self-scheduling and choose to receive a fixed payment (associated with holding onto ARRs) in other months. Therefore, LEI recommends exploring changes to the ARR process that would allow ARR holders to self-schedule during monthly auctions and/or allow ARR holders to self-schedule only in particular months during the annual FTR auction.[158]

The current self-scheduling process is also restrictive to load as the only decision ARR holders can make during the annual ARR process is how many MW of ARR they would like to self-schedule. In other words, load has to decide to self-schedule before they know the FTR auction results. In theory, load can artificially create a "limit order" equivalent trade by submitting a counterflow bid in the FTR auction and at the same time self-schedule their ARR. In this case, if the counterflow bid clears, it will offset the self-scheduled path, effectively creating the same effect as a limit order. However, according to PJM staff, load rarely carries out such trades, possibly because this option is not well known to ARR holders or such a strategy is considered costly (due to additional trading fees/credit costs) or too risky in case the counterflow trade cannot be cleared for all four rounds of the auction. Therefore, LEI recommends PJM add an explicit "limit order" feature for ARR holders to enter during the self-scheduling process. Load can benefit from a limit order enhancement by having more certainty over the tradeoff they are making when deciding to the hold ARR versus self-schedule. This enhancement, combined with allowing more granular self-scheduling of ARRs and opening up more nodes for load to nominate during the ARR allocation process, could result in a more active ARR allocation process.

8.5 FTR auctions should be retained, including the long-term FTR auction

Based on our findings in Section 6.7, LEI recommends the current set of FTR auctions be retained, and rules regarding participation and biddable points remain unchanged.

LEI also suggests PJM and the IMM continue monitoring the FTR auctions' competitiveness. If there is evidence suggesting that load is systemically disadvantaged in FTR auctions or any

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[157] For detailed statistical analysis on FTR auction's predictive power on congestion over different timeframe, refer to Appendix E (Section 13).

[158] Allowing ARR holders to self-schedule specific months during the annual FTR auction may also require changes in the products available in the annual FTR auction and enhancements to the market-clearing engine. This is because for months where the ARR holder did not self-schedule in the annual auction, they require corresponding FTR auction clearing prices to determine their ARR target allocations. However, if there is no corresponding monthly FTR auction clearing prices because there are no monthly FTR products being auctioned during the annual FTR auction, the mechanism would not be functional. Therefore, changes to ARR self-scheduling flexibility would also require changes to the FTR auction design.

specific types of paths, PJM and the IMM should identify the root cause of such disadvantages, be it a market rule issue, a competition issue, or information asymmetries.

8.6 FTR auction clearing engine should be enhanced to prevent underpriced FTR options

In Section 6.11, LEI identified over 10,000 MW of FTR options sold in the past six planning periods that can be deemed as underpriced.

The reason underpriced FTR options cleared is that the FTR auction engine employed by PJM has not required a specific premium for clearing FTR options. Based on PJM's Manual 06, the only two rules the auction engine follows when clearing FTR options are that the options clearing price cannot be below $0/MW, and it cannot be below the clearing price of the obligation in the same path.[159]

LEI recommends PJM enhance the clearing engine rule to require options clearing at a minimum premium over $0/MW as well as minimum premium above the price of the FTR obligation for the same path. The minimum premium could be as simple as a fixed $/MW based on historical observation of the expected congestion charges earned on the traded path or using a more sophisticated options pricing approach such as a modified Black-Scholes model tailored for FTR options to calculate the fair option premium on each path.

8.7 Study whether forfeiture rule can be relaxed

Since the implementation of the current FTR forfeiture, $22 million of FTR target allocations have been "forfeited" or "clawed back." On average, 43 forfeiture events have happened per month, and more than 1,400 FTR market participants (i.e., entities) have been affected by the FTR forfeiture rule.[160] This means that over 80% of FTR market participants have been impacted.[161]

FGD participants, including both load and non-load entities, had expressed concerns that the forfeiture rule has been overly mitigative. This rule has forced market participants to choose between FTRs or virtual transactions in the energy market. One stakeholder explained the illogical outcomes that the current FTR forfeiture rule by noting in the FGD session that virtual transaction in a distant part of PJM affected the FTR target allocation of an FTR path in a different part of PJM. Market participants may not have visibility into network dynamics that trigger such a claw back. Therefore, they cannot adjust their offer behavior to prevent a claw back. The deterrent effect of the FTR forfeiture rule is therefore not practical. Consequently, some market participants have had to leave either the virtual market or the FTR market to avoid being affected

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[159] PJM Manual 06 Section 6.2.

[160] Based on data provided by the IMM.

[161] Based on data provided by the IMM, there are around 1,650 unique market participants (entities) in the FTR market.

by the claw backs. Over time, this may undermine liquidity in the FTR auction or the virtuals. Such anecdotal evidence indicates the FTR forfeiture rule may not be accomplishing what it was intended to do.

In our review of case studies in other RTOs, LEI found that ERCOT and MISO do not have any forfeiture rule while CAISO has something similar to PJM, called the CRR Settlement Rule or Claw Back Rule. However, there are differences between CAISO's and PJM's forfeiture rule. For instance, PJM has the $0.01 threshold impact on the transaction to the target allocation, in addition to the capacity threshold (greater of 0.1 MW or 10% or more).[162] CAISO does not have this; CAISO only has the capacity threshold. Moreover, in conjunction with the CRR Settlement Rule, CAISO provides market participants with crucial information to monitor their own behavior.[163] These materials include the DFAX for each constraint that binds in the day-ahead and real-time market and transmission limits for all constraints in the day-ahead and real-time markets, both within three calendar days of the market day.[164] The availability of this data is important so that market participants can rectify their trading decisions appropriately.[165]

In summary, LEI recommends that the current FTR forfeiture rule is re-evaluated.

8.8 PJM should enhance its network model transparency

To improve satisfaction with the ARR allocation process and auction outcomes, LEI proposes several improvements to the publicly released details and the network model's description. For instance, MISO provides a network model manual that has a detailed description of the purpose, data considered, and maintenance process, to name a few.

Also, LEI recommends that PJM provide more detailed documentation of changes made to the network model since the last public release, as well as document business practices and the extent of manual adjustments that staff can make to the network model. Moreover, PJM may want to consider retaining an independent transmission expert to independently review the network model periodically (e.g., every 3 or 5 years). These will address the concerns of several stakeholders with regard to the transparency of the network model. The network model is used to conduct SFTs in both the ARR process and in the FTR auctions. Therefore, the additional transparency will assist with achieving both purposes.

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162 In PJM, the forfeiture rule is triggered when a participant's net virtual portfolio affects a constraint by greater of 0.1 MW or 10% or more of the limit, and that constraint impacts an individual's FTR's target allocation by $0.01.

163 XO Energy LLC. "Complaint of XO Energy LLC." Filling under FERC Docket Number EL-20-41-000. April 8, 2020. p. 50.

164 Ibid.

165 Ibid. p. 4.

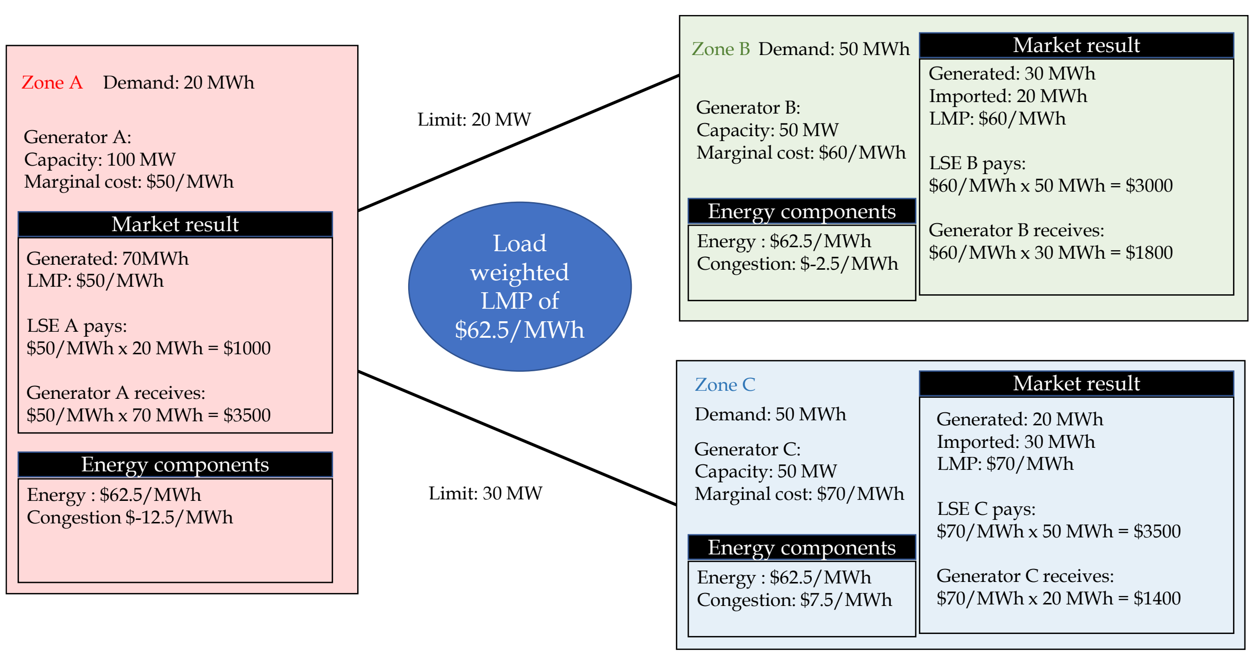
9 Appendix A: Numerical example of how congestion charges arise

This numerical example is intended to show how congestion charges arise. In this simple example, we have three load zones: zone A, B, and C, with LSEs and generators located in each zone.

The fact pattern for this example includes the following:

- The demand for Zone B and Zone C is 50 MWh each, while the demand in Zone A is 20 MWh.
- Generators A, B, and C have different capacities (100 MW, 50 MW, and 50 MW, respectively) and different short-run marginal costs ($50/MWh, $60/MWh, and $70/MWh, respectively).
- There are two transmission lines, one between zone A and B, and another between Zone A and C. The A-B line has a 20 MW transmission limit, and the A-C line has a 30 MW limit. For simplicity, we assumed there are no marginal losses.

Figure 51. Illustration of a 3-zone system with congestion



System operations, based on the least cost principles, results in the following outcomes:

- Generator A, as the lowest cost generator, is dispatched to meet the demand for all three zones, subject to transmission limit – which means it generates 20 MWh to meet demand in Zone A, 20 MWh delivered to Zone B, and 30 MWh delivered to Zone C, totaling 70 MWh.

- Generator B and Generator C are also dispatched to meet the amount of residual load in their local zone as the transmission from Zone A is not enough to meet Zone B and Zone C's local demand – i.e., Zone B and C are import constrained.
- Therefore, Zone A, B, and C all have different locational marginal prices of $50/MWh, $60/MWh, and $70/MWh, respectively.

Figure 52. Funds ISO collected and disbursed in the 3-zone example

ISO collected from load:		**ISO paid to generators**:	
Load A:	$1,000	Gen A:	$3,500
Load B:	$3,000	Gen B:	$1,800
Load C:	$3,500	Gen C:	$1,400
Total:	$7,500	Total:	$6,700

ISO collected from load – ISO paid to generators = Congestion charge

$7,500 - $6,700 = $800

During settlement, load pays their demand times the LMP, and the generator gets paid the amount they generated times the LMP. As shown in the figure, the ISO collects more from load than they paid to generators, resulting in an overpayment of $800. Overpayment is the difference between what load pays to the ISO and what the ISO pays to the generators due to the LMP construct with congestion. This difference is the congestion charge.

Now we move on to what customers see in the bill they receive from the ISO's settlement system, as illustrated in Figure 53. The reference bus price, defined as the weighted average LMP of all three zones,[166] is $62.5/MWh. Since the congestion component of the LMP (i.e., CLMP) is defined as the difference between the LMP and the reference bus price, the CLMP of zones A, B, and C are $-12.5/MWh, $-2.5/MWh, and $7.5/MWh, respectively.

In the bill, a customer will see the LMP broken down by the energy component and the congestion component (and a marginal loss component, which is assumed to be zero in this illustration). The energy component would be the same for all zones because it is defined by the reference bus price. The congestion component in each zone would be different as the LMP for each zone is different. Each customers' bill will identify the energy consumed or generated; these volumes drive the calculation of the energy charges and congestion charges (energy consumed/generated x energy price, and energy consumed/generated x congestion component), as shown in the tables

166 There are multiple ways to define a reference bus – it is an arbitrary construct for the purpose of dissecting the LMP into multiple components.

below. If the congestion charge component for all loads and generators is added up, it totals $800 – precisely the amount of "overpayment" of congestion charges.

Figure 53. Illustration of individual customer's bills in the 3-zone example

Load A bill	Generator A bill
Energy : $62.5/MWh Congestion: $-12.5/MWh Energy consumed: 20 MWh Energy charge: $1,250 Congestion charge: $-250 Total: $1,000	Energy : $62.5/MWh Congestion: $-12.5/MWh Energy consumed: -70 MWh Energy charge: $-4,375 Congestion charge: $875 Total: $-3,500
Load B bill	**Generator B bill**
Energy : $62.5/MWh Congestion: $-2.5/MWh Energy consumed: 50 MWh Energy charge: $3,125 Congestion charge: $-125 Total: $3,000	Energy : $62.5/MWh Congestion: $-2.5/MWh Energy consumed: -30 MWh Energy charge: $-1,875 Congestion charge: $75 Total: $-1,800
Load C bill	**Generator C bill**
Energy : $62.5/MWh Congestion: $7.5/MWh Energy consumed: 50 MWh Energy charge: $3,125 Congestion charge: $375 Total: $3,500	Energy : $62.5/MWh Congestion: $7.5/MWh Energy consumed: -20 MWh Energy charge: $-1,250 Congestion charge: $-150 Total: $-1,400

10 Appendix B: Overview of the ARR/FTR evolution

PJM's FTR and ARR mechanisms were established in 1998 and 2003, respectively. Rules changes over the years have evolved the mechanisms, specifically as it relates to settlement rules and arrangements for allocating ARRs and trading FTRs. However, original conceptual basis for the ARR/FTR design has remained unchanged. To evaluate the current mechanisms, LEI researched the ARR/FTR market design evolution. This Appendix details the critical changes in ARRs and FTRs since inception. Figure 54 and Figure 55 highlight the key milestones in the development of PJM's ARRs and FTRs from the late 1990s to 2020.

Figure 54. Key changes to the FTR mechanism

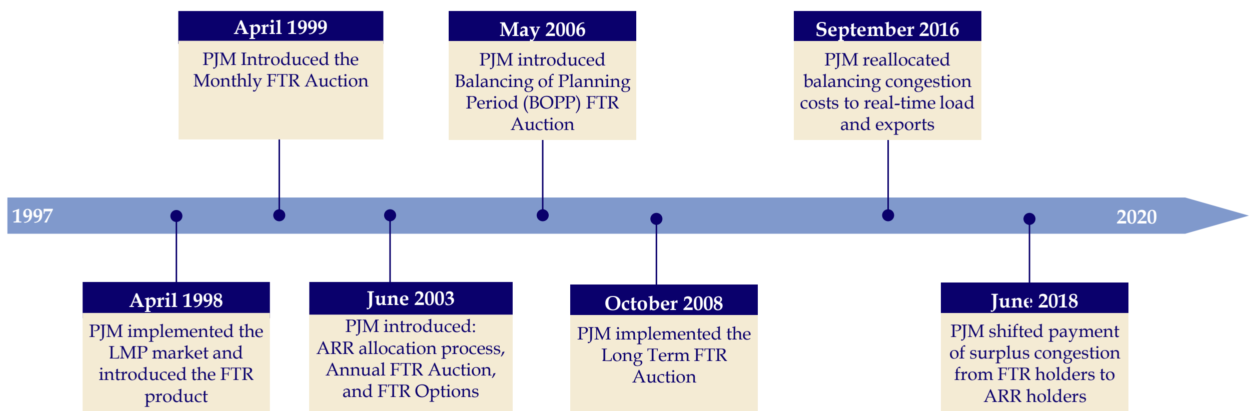
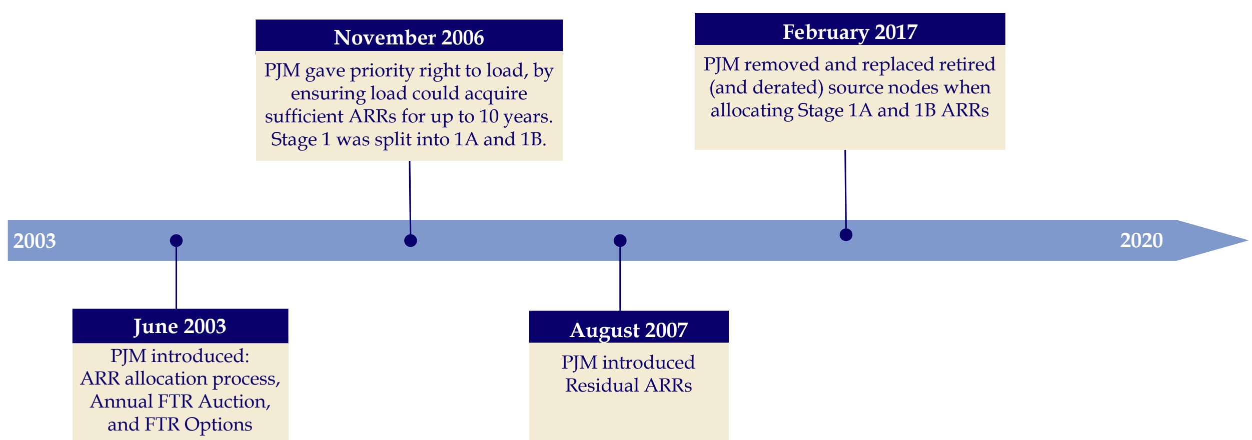


Figure 55. Key changes to the ARR mechanism



Source: FERC Orders, 1997-2018.

10.1 Initial years

On April 1, 1998, PJM implemented the LMP spot market system and introduced FTRs. At that time, FTRs settled against the real-time energy market, as the day-ahead energy market was not introduced until 2000. Initially, FTRs were directly allocated to firm transmission service customers based on their specific reserved source and sink points of energy delivery.[167]

As discussed in Section 3, the need for FTRs arose out of the decision to move to LMP-based spot markets and the FERC mandate to open access to the transmission system. Market designers selected the LMP design for spot markets because it ensured efficient use of the transmission system and therefore created efficient production and consumption decisions in the spot market. However, market designers and regulators recognized that LMP markets would not replace existing commercial arrangements. Bilateral trading and forward markets would continue, and the LMP system would need to be able to work collaboratively with those commercial arrangements. For that reason, a path-based (or point-to-point) system was selected for FTRs.

On April 13, 1999, PJM implemented a monthly auction for FTRs. The purpose of the auction was to allow market participants (even non-LSEs) the opportunity to acquire residual FTRs, and also provide an opportunity for firm transmission service customers to sell their FTRs (that they had been directly allocated).[168] In summary, the monthly auction provided an easy way for LSEs to reconfigure their portfolio of FTRs.[169] This change recognized the theoretical importance of trading property rights.[170]

The following year, on June 1, 2000, PJM introduced the day-ahead energy market.[171] The day-ahead energy market allowed participants to enter financially-binding purchase or sale of energy one day ahead of the real-time market. Day-ahead energy markets also used the same LMP system as was already in use in the real-time energy market. Any differences between the day-ahead and real-time prices would now be settled through energy imbalances.[172] The FTR product definition was revised to settle on the congestion components from both the day-ahead and real-time energy prices to complement this new system.[173]

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[167] FERC. Federal Energy Regulatory Commission. 81 FERC ¶61,257. Washington D.C., 2001. p. 35.

[168] FERC. Federal Energy Regulatory Commission. 87 FERC ¶61,054. Washington DC, 1999. p. 2.

[169] Ibid.

[170] According to the Coase Theorem, the trading of property rights (with minimal transaction costs) can ensure an efficient equilibrium, regardless of the initial allocation of property rights. Transaction costs and barriers to trading can obstruct efficient outcomes. *See* Robson, Alex. S. Skaperdas. "Costly enforcement of property rights and the Coase Theorem." Economic Theory, July 2008, Vol. 36, No. 1. pp. 109-128.

[171] PJM Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM," 2000. June 2001.

[172] Ibid.

[173] Ibid.

10.2 Addition of ARRs

On January 10, 2003, PJM submitted a filing to FERC, proposing to create a new property right – namely ARRs. In this filing, PJM also proposed implementation of an ARR allocation process, introduction of an annual FTR auction and addition of FTR options to the current FTR obligation product.[174] PJM noted that these changes were requested by PJM customers. There were three goals for introducing ARRs: (1) provide greater liquidity for the FTR market, (2) improve on the efficient allocation of scarce FTRs, and (3) create additional options for customers to hedge congestion risk.[175]

On March 12, 2003, FERC officially accepted PJM's filing, and on June 1, 2003, PJM introduced ARRs, which replaced the original FTR allocation process. Unlike FTRs, whose value is linked to the realized congestion in the day-ahead energy market, ARRs derived their basic value from the FTR auctions, which reflects market *expectations* about congestion in the day-ahead energy market. The ARR mechanism is further described in Appendix C (Section 11.1).

10.2.1 Long-Term Transmission Rights and the revision to the ARR Stage 1 Allocation (2006)

In 2005, the Federal Power Act was amended to grant FERC the power to require public utility transmission organizations to provide long-term transmission rights to LSEs.[176] FERC provided a set of guidelines to meet the long-term transmission rights, which are described in the textbox below. In response to the FERC guidance, PJM revised the ARR construct to comply with the FERC's ten-year transmission right requirement. As such, PJM gave priority rights to load to network capacity by ensuring that all load could acquire sufficient ARRs for up to 10 years.[177]

To accommodate this guarantee, Stage 1 ARR allocation was split into Stage 1A and 1B, where Stage 1A would allow PJM to determine if the ten-year ARRs would be feasible alongside all other Stage 1A ARRs for the subsequent years.[178] LSEs could request up to 50% of their baseload levels in the prior year in Stage 1A, as described further in Appendix C (Section 11.1).

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174 Note that Incremental ARRs (IARRs) were previously known as Incremental FTRs and were allocated directly to load. With the introduction of ARRs, Incremental FTRs were automatically reconfigured as IARRs in the 2003 FERC Order.

175 PJM. PJM Interconnection LLC. Filing: ER06-1218-000., Washington D.C., 2006.

176 FERC. 116 F.E.R.C. P61,077. Washington D.C., 2006.

177 PJM. PJM Interconnection LLC. Filing: ER06-1218-000., Washington D.C., 2006.

178 Ibid.

FERC guidelines to meet long-term transmission rights, est. 2005

1. Specify source, sink and quantity of the long-term transmission rights;
2. Provide long-term hedges against LMP congestion charges for a specified quantity and period, which could not be modified;
3. Allow for the paying parties of transmission upgrades or expansions to receive long-term transmission rights for their developments (subject to feasibility);
4. Provide long-term transmission rights that would match or meet LSE's need for hedging their long-term power supply;
5. Grant LSE priority over non-LSEs for long-term transmission rights allocation;
6. Allow for reassignment of long-term transmission rights between loads; and
7. No need for recipients to participant in the auction to receive long-term transmission rights.
8. Allocation of long-term transmission rights should balance the adverse economic impact of participants receiving, and not receiving, the rights.

10.2.2 Residual ARRs (2007)

On August 13, 2007, FERC approved PJM's request to add a Residual ARR product. Residual ARRs are directly allocated to load when new transmission capacity developed during the Planning Period becomes available.[179,180] However, it should be noted that Residual ARRs cannot be converted to FTRs, unlike regular ARRs, as they are allocated after the annual FTR auction. The purpose of creating the Residual ARR was to remedy the ARR pathways that were prorated during Stage 1 of the annual allocation process, because of SFT constraints.[181]

Furthermore, potential transmission outages may also cause requested ARRs to not pass the SFT. As such, LSEs may instead receive a prorated amount of their ARR request in the annual allocation. The addition of Residual ARRs, once transmission outage constraints are ameliorated,

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[179] PJM. PJM Interconnection LLC. Filing: ER07-1053-000., Washington D.C., 2007.

[180] Once Residual ARRs have been allocated, they would be available as regular ARRs in the following annual ARR allocation process since the new transmission system would be included in the subsequent versions of PJM's network model. *See* PJM Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM, 2007." March 8, 2008.

[181] SFT is further discussed in Section 11.1.

is consistent with and enhances Purpose #1 of FTRs, by providing load with a priority right to the network.[182]

10.2.3 Reflecting retired generation in the ARR allocation process (2007)

On January 31, 2017, FERC accepted PJM's proposed change to remove and replace retired (and derated) source nodes when allocating Stage 1A and 1B ARRs.[183] This change would ensure that Stage 1 ARR allocations are reflective of the actual resources that would impact energy flows on the transmission system. Specifically, PJM replaced source points associated with retired generators or generators that have reduced their installed capacity with an equivalent number of MWs for operating generators, defined as Qualified Replacement Resources ("QRRs").[184] QRRs are identified on an annual basis (prior to the relevant planning period) and has to meet the criteria of: a generation resource that has a determined installed capacity value for the delivery year and is not presently identified as an ARR historical resource, pass a SFT, and to maximize the economic value of ARRs.[185] Additionally, the QRRs should not increase the MW flow to facilities in the current ARR allocation or future Stage 1A allocation.[186]

This adjustment mechanism to the historical paths used in the ARR process was necessary because PJM started to experience a wave of retirements in 2015 (as shown in Figure 56 on the next page),[187] and therefore the historical generation to load paths previously used for ARR allocation were getting outdated and inaccurate of the actual transmission usage within PJM.[188, 189] This discrepancy between PJM's Stage 1 ARR allocation modeling and actual system usage created several problems. First, the use of retired generation sources led to inaccurate results in the SFT for Stage 1 ARRs. For example, a historical path that contained a retired generation source could lead to the rejection of a new ARR request. However, in actuality, the transmission lines were not overloaded, and the new ARR request could have been feasible. The change resolved a

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182 According to the State of the Market Report, 2019, PJM allocated a total of 26,262.6 MW of residual ARRs, down from 31,554.6 MW in 2018. This amounted to an ARR target allocation of $11.7 million for 2019, and $15.3 million for 2018, respectively.

183 FERC. 156 F.E.R.C. P61,180. Washington D.C., 2016.

184 FERC. 158 F.E.R.C. P61,093. Washington D.C., 2017. p. 33.

185 FERC. 158 F.E.R.C. P61,093. Washington D.C., 2017. p. 34.

186 Ibid.

187 In 2015, there was four times more generation source retirements in comparison to the previous year. The uptick of generation source retirements made it a necessity to revise the historical generation to load paths for ARR allocations.

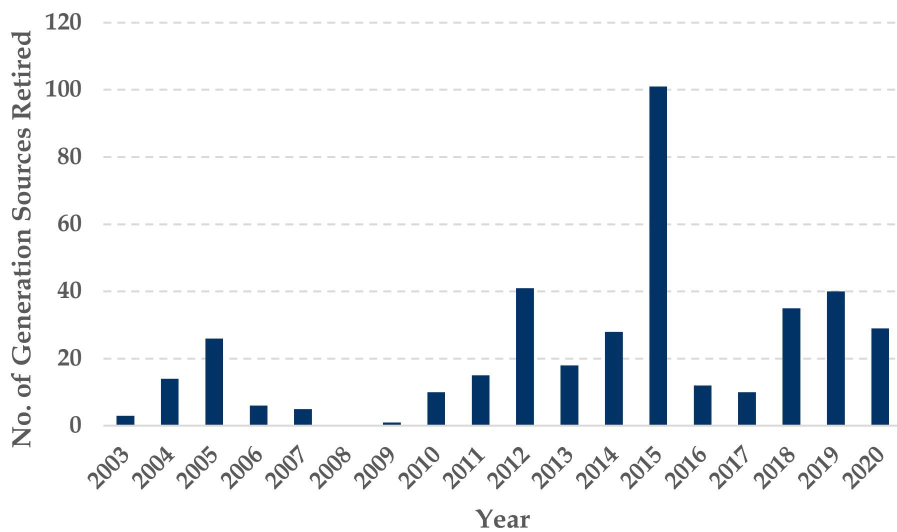
188 The historical reference year dates to 1999 or depending on when the transmission zone joined PJM.

189 FERC. 156 F.E.R.C. P61,180. Washington D.C., 2016.

potential fairness issue for LSEs, since requests for nominating ARRs (that could have been feasible) would have erroneously been rejected.

A disconnect between the historical source generation and actual system usage could also lead to an improper investment signal. For example, a market participant may invest in transmission to relieve congestion; however, this investment may be unnecessary, as the retired generation may have relieved network congestion and created headroom on the system. Ultimately, allowing for more up-to-date ARR source points also improved the investment signal, supporting the objectives covered by Purpose #2.

Figure 56. Total retirement of generation sources in PJM, on an annual basis



Source: PJM. Generation Deactivations. https://www.pjm.com/planning/services-requests/gen-deactivations.aspx

10.3 Key changes in FTRs since 2003

After the introduction of ARRs in 2003, various developments continued to occur in the FTR market, including the addition of more FTR paths, addition of more FTR auctions, and changes in settlement of FTRs. In the aggregate, these developments improved the efficiency of the FTR auctions, which improvement the ability to achieve both Purpose #1 and Purpose #2.

10.3.1 Introduction of annual FTR auction and FTR options (2003)

In 2003, in conjunction with the introduction of ARRs, FERC accepted PJM's proposed tariff changes adding an annual FTR auction and an FTR option product. The annual FTR auction allowed LSEs to monetize the value of ARRs. The annual FTR auction also enabled participants to buy or sell year-long FTRs to meet their needs for hedging congestion and obtain information on the value of their FTRs. The combination of self-scheduling and an annual (planning period) tenure resulted in increased competition and liquidity.[190]

The addition of FTR options also provided an insurance-like approach for hedging congestion risk, where load may not necessarily have a matching bilateral contract for the source and sink points. FTR options are described in Appendix C (Section 11.2).

10.3.2 Monthly Balance of Planning Period FTR auctions and long-term (3-year forward) FTR auctions (2006)

On November 2, 2005, PJM proposed two new intermediate-term FTR products in response to market participants' request for FTRs that cover terms longer than one month but shorter than one year. The two new products were:[191]

- the Balance of Planning Period ("BoPP") FTR product class, which covered a multi-month period extending through the remaining months of a planning period. The BOPP auctions were held at the beginning of each month after the monthly FTR auction; and

- the Planning Period Quarter FTR product, which covered the remaining quarterly periods within the planning period.[192]

10.3.3 Long term FTR auctions (2008)

In 2008, PJM introduced the Long Term FTR ("LT FTR") auctions to provide a platform for market participants to trade FTRs products that are (i) longer than one planning period, and (ii) single planning period FTRs that could be used in subsequent planning periods.[193] The LT FTR auctions afforded market participants (including LSEs and non-load entities) the ability to lock in congestion costs on a specific path for a future period, up to four years from the date of the auction. Participants could buy any source and sink points for 24-hour, on-peak, or off-peak blocks, based on the "residual system capability" (based on ARR paths), as discussed in Appendix

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[190] FERC. "Federal Energy Regulatory Commission. 102 FERC ¶ 61,276. Washington DC, 2003. p. 7.

[191] PJM. PJM Interconnection LLC. Filing: ER06-150-000., Washington D.C., 2005. p. 2.

[192] Since the 2018/2019 planning period, the Planning Period Quarter FTR product is no longer available. But participants are able to continue to bid for any single calendar month remaining in the planning period. *See* PJM. "PJM Manual 6: Financial Transmission Rights." p. 41.

[193] PJM. PJM Interconnection LLC. Filing: ER06-150-000., Washington D.C., 2006.

C (Section 11.2.1).[194] LT FTR auctions only provide for the sale of FTR obligations, because FTR options would be difficult to model and account for in the long-term.[195]

10.3.4 Balancing congestion (2016-2017)

> *"The Commission found that, under these circumstances, the continued inclusion of balancing congestion in the definition of FTRs would result in either the chronic under-funding of FTRs, or the unrealized value of ARRs for certain load serving entities, to the detriment of both participants in PJM's real-time markets and, under certain circumstances, the holders of the underlying transmission rights."*
>
> - FERC Order, 158 FERC ¶ 61,093 (January 31, 2017)

On September 15, 2016, FERC ruled to remove balancing congestion (see the textbox to the left) from the FTR settlement. This meant that FTRs would only settle using day-ahead energy market outcomes. The liabilities associated with balancing congestion costs would be borne by real-time load and exports, because the change in real-time load and exports from the day-ahead market schedule typically causes balancing congestion.[196]

Until this time, balancing congestion charges had been paid by FTR holders. PJM found that the allocation of these charges to FTR holders distorted the FTR auction outcomes. Since balancing congestion is typically a liability (rather than a benefit), market participants had to account for expected charges in their offer price. The risk of having to pay for balancing congestion led to lower FTR auction revenues, hurting ARR holders.[197] PJM also concluded that associating balancing congestion with FTRs led to the underfunding of FTRs, and FERC agreed.[198]

This change to the FTR definition is consistent with Purpose #1 of returning congestion payment from LMPs back to load (because of the improvement in ARR value). It also supports Purpose #2, by removing discounts that were previously embedded in FTR auction offers due to underfunding, this change made FTR auction outcomes more reflective of expected congestion in the day-ahead energy market, which improved the price discovery provided by FTR auctions.

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194 Simultaneous Feasibility Test are further discussed in Section 3.2.1.

195 Additionally, the inclusion of FTR options would significantly increase the number of scenarios that would have to be modeled in the SFT to assure revenue adequacy. See Parmeswaran, Vijay, and Kumar Muthurman. "FTR-Option Formulation and Pricing." Electric Powers System Research (March 26, 2009).

196 PJM. PJM Interconnection LLC. Filing: ER18-1245-000, March 30, 2018.

197 FERC. 158 FERC P61,093. Washington D.C., January 31, 2017. p. 21.

198 FERC. 156 F.E.R.C. P61,180. Washington D.C., 2015.

10.3.5 Surplus congestion (2018)

On June 1, 2018, FERC accepted PJM's request to shift payment of surplus congestion from FTR holders to ARR holders. Starting with the 2018/2019 planning period, surplus congestion has been paid out to load on a pro-rata basis to their positive ARR target allocations.[199] PJM requested this change to align the FTR and ARR mechanisms with Purpose #1. Surplus congestion occurs only because the network model used by PJM to allocate ARRs and to clear FTRs in the annual and monthly FTR auctions is under-forecasting the extent of network capacity that is available in the day-ahead energy market. So, the existence of surplus congestion can be traced to a problem of ARR under-allocation. Therefore, it is reasonable that load should be the recipient of this surplus congestion.[200,201]

This is a significant change in the amount of congestion charges now received by load. From 2014/15 to 2019/20, the annual surplus congestion averaged $89 million, ranging from the low end of $23 million to a high end of $142 million. In the 2018/19 and 2019/20 planning periods, when surplus congestion changes were implemented, these funds represented 18%, and 21% of the total congestion charges returned to load.

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[199] FERC. 163 F.E.R.C. P61,165. Washington D.C., 2018. p. 2.

[200] Ibid.

[201] Notably, in this decision, FERC also clarified that full funding of FTRs is not guaranteed and that FTR holders take on the potential risk of under-funded FTRs.

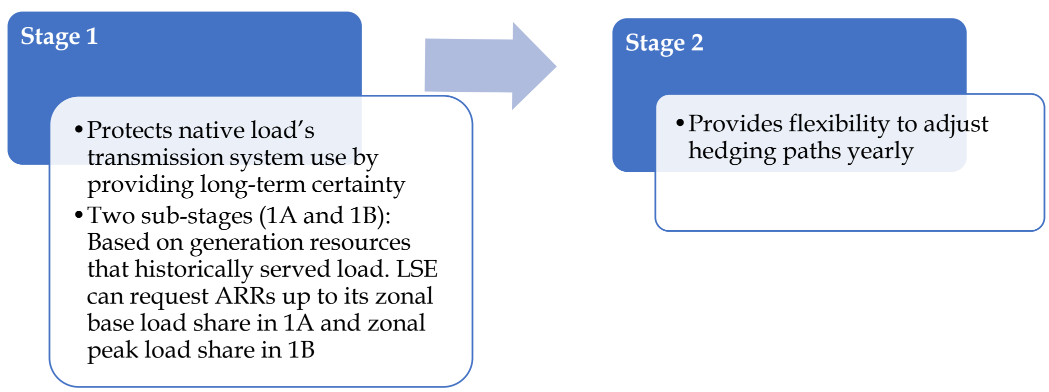
11 Appendix C: ARR/FTR mechanisms in PJM

This Appendix provides a more detailed description of the ARR and FTR mechanism currently in place in PJM. This is useful background information for understanding the detailed mechanics of the ARR allocation process, range of FTR products and timing of auctions, and settlement.

11.1 ARR allocation process

ARR allocation is done in three stages: Stage 1A, 1B, and Stage 2, as summarized in Figure 57. In both Stage 1A and 1B, PJM assigns ARR sources for each zone from resources historically designated to serve load[202] in the zone. Stage 2 involves three rounds that allow LSEs to request additional ARRs from various potential ARR source points (for example, hubs and generation nodes outside their zone).

Figure 57. Stages in the ARR allocation process



In Stage 1, PJM determines the set of eligible ARR sources for each transmission zone from resources historically constructed to serve load in that zone as of the reference year.[203] ARRs allocated in Stage 1A come from active historical generation resources or qualified replacement resources. [204] PJM will also assign each LSE a pro-rata amount of the MW capability from each generator designated[205] to the transmission zone, based on the LSE's percentage of the total peak

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[202] 1999 is the reference year for the original utilities that joined PJM back in 1997. The historical reference year for other PJM members varies with the date they joined PJM. For instance, for ATSI, the reference year for ARR allocation is 2010, the year that it joined PJM.

[203] This year depends on the date the transmission utility joined PJM.

[204] Starting in 2017/2018 Annual ARR, PJM replaced retired generators that were previously used as eligible ARR sources with new resources. *See* PJM. "PJM Manual 6: Financial Transmission Rights." p. 20.

[205] Designated means active generation resources that have historically served a particular transmission zone.

Baseload is defined as the minimum of daily peak loads for each transmission zone from the previous year, escalated by projected load growth

- Source: "Workshop on PJM ARR & FTR Market – Part 3"

load in the transmission zone.[206, 207] An LSE then submits ARR requests through PJM's web-based portal known as the *FTR Center* and chooses the set of ARRs that it wants based on pre-assigned generator sources up to its baseload in Stage 1A. The allotted ARRs in Stage 1A cannot go beyond the Network Services Customers' total **baseload** in that zone or load aggregation zone.[208,209]

Next, PJM conducts a simultaneous feasibility test (or SFT) using its network model (see textbox on page 129 for an explanation of the SFT), to confirm the feasibility of all sets of ARRs awarded to each LSE involved in the ARR process.[210] Once the SFT demonstrates the feasibility of all the ARRs, PJM notifies each LSE of the ARR awards resulting from the Stage 1A allocation process.

Stage 1A guarantees transmission capacity allocation for ten years, a requirement under EPAct 2005. More specifically, Stage 1A awards are guaranteed for each LSE at baseload levels. If the network model cannot ensure simultaneous feasibility of all Stage 1A requests, and therefore PJM is required to make awards on a pro-rata basis, then PJM's tariff requires that it work with transmission owners to ensure that the network upgrades to support ARR guarantee levels are attained. For example, in 2012, PJM found constraints in its network model on the amount of Stage 1A ARRs it could award to LSEs in the Commonwealth Edison Company zone. Therefore, PJM proposed a transmission upgrade as part of the Regional Transmission Expansion Plan

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[206] This can be done on a transmission zone basis or under a historic load aggregate zone. PJM's Manual 6 defines historic load aggregation as "a sub-region of a transmission zone that was served under a separate set of supply contracts and/or generation resources (i.e., by a municipal or cooperative utility) than the other non-municipal/cooperative load in the transmission zone." *See* PJM. "PJM Manual 6: Financial Transmission Rights." p. 23.

[207] PJM. "PJM Manual 6: Financial Transmission Rights." pp. 21-22.

[208] PJM. "PJM Manual 6: Financial Transmission Rights." p. 20.

[209] In slight contrast to LSEs, firm point-to-point customers may request up to 50% of their MWs of firm service provided between receipt and delivery points during the reference year. *See* PJM. "PJM Manual 6: Financial Transmission Rights." p. 20.

[210] The SFT ensures that all ARRs awarded relate to network capacity that is likely to exist in the spot market. In the FTR auctions, on the other hand, the SFT is needed to make sure there is adequate revenue to meet the FTR payment obligations.

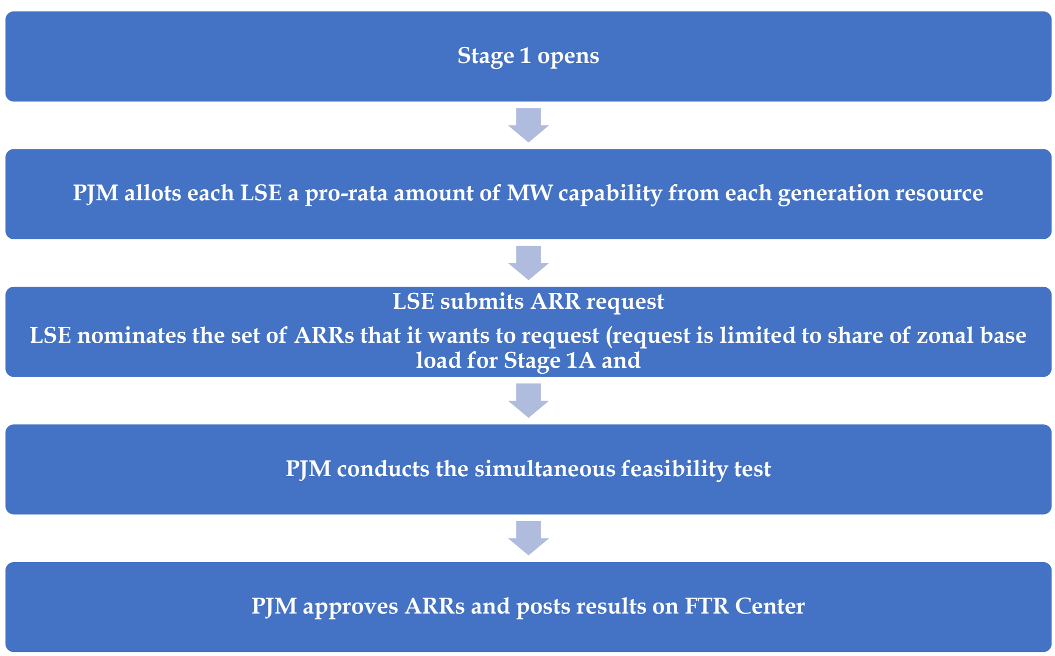
("RTEP") process to remedy this ARR allocation issue (e.g., the Grand Prairie Gateway project, which was completed in 2017).[211]

PJM's network model and the SFT

PJM does not know in advance how the power system will work in the spot market so it needs to model and predict network operations to quantify the amount of ARRs so the allocation may be reasonably undertaken, and the PJM auction cleared through the SFT.

To perform the SFT, PJM uses a DC power flow model (the "network model") that includes the following inputs: all newly-requested FTRs and ARRs for the modeling period, existing FTRs and ARRs, scheduled transmission outages, and estimated uncompensated power flow circulation into the PJM control area from outside control areas. If requested ARRs or bids to buy FTRs are determined to be simultaneously feasible in the network model, then PJM can move with the award of ARRs/FTRs. However, if the ARR allocation round or the FTR auction rounds fails the SFT, PJM would need to pro-rate the ARRs/FTRs.

Figure 58. Annual allocation process in Stage 1



Source: PJM training materials and PJM Manual 06: Financial Transmission Rights.

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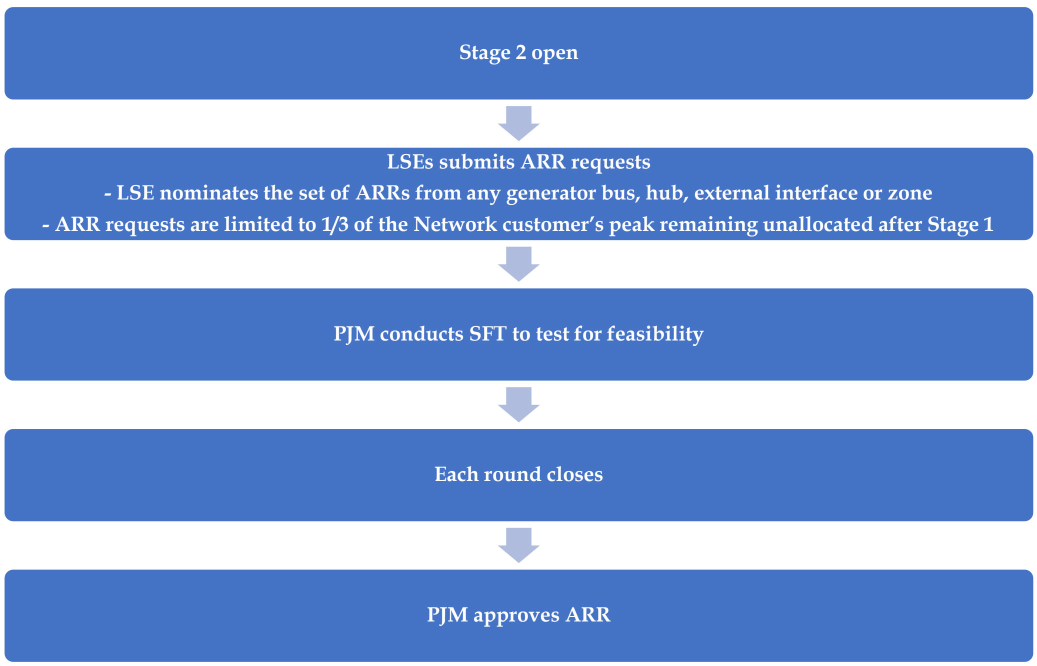
211 ComEd. "ComEd's Grand Prairie Gateway Project Is Complete." https://www.comed.com/SmartEnergy/InnovationTechnology/Pages/GrandPrairieGatewayProject.aspx

In Stage 1B, firm transmission customers may request ARRs up to the remainder of the MW of firm service not awarded in Stage 1A. More specifically, the ARR amount allocated to a transmission zone or load aggregate zone cannot go over the Network Services Customers' total network peak load in that zone (or load aggregation zone) less than the awarded ARRs from Stage 1A. PJM also conducts an SFT to confirm the Stage 1B requests. Figure 58 shows the allocation process in Stage 1.

According to PJM, 95% of the network capacity is allocated in Stage 1.[212] It is important to note that this does not imply that all LSEs received ARR capacity equivalent to their peak load. For example, in planning periods 2017/18 and 2018/19, ARRs allocated cover approximately 62% of the peak load of all LSEs on a combined RTO-wide basis.[213]

Figure 59. Annual allocation process in Stage 2



Sources: PJM training materials and PJM Manual 06: Financial Transmission Rights.

PJM also hosts a Stage 2 allocation process for ARRs. Figure 59 shows the Stage 2 allocation process. LSEs are allowed to request ARRs that can cover the rest of the network peak load (or MWs of firm transmission service) in this stage. Similar to Stage 1, an ARR request is submitted via *FTR Center*. Unlike in Stage 1, however, there is no pre-assigned list of source points. In Stage 2, a request for ARRs may have a source point in any load zone and at any available generator

[212] Conference call with PJM Staff. September 9, 2020.

[213] LEI analysis based on data provided by PJM.

bus, hub, or external interface for which PJM calculates and posts a day-ahead congestion price value.[214] The sink point of each ARR request must be the LSE's transmission zone or load aggregation zone. PJM performs an iterative allocation process that entails three consecutive rounds in Stage 2, with each round allocating a third of the remaining system's ARR capability. In each round, network customers can only request up to one-third of their peak load that was unallocated after the Stage 1 process. PJM performs an SFT analysis after each round in Stage 2.

11.1.1 How is the economic value of the ARR measured?

ARRs are valued based on the expected CLMPs emerging from the annual FTR auction. The value of an ARR arising out of the Annual FTR auction is known as ARR target allocation and is equal to the ARR MW amount multiplied by the average LMP difference between the sink and source over the four rounds the annual FTR auctions (Figure 60). The ARR target allocation is supposed to represent the maximum payout that an ARR holder would receive for his ARRs.

Figure 60. ARR target allocation formula

$$\text{ARR Target Allocation} = (\text{ARR MW}) \times (\text{LMP}_{\text{ARR Sink}} - \text{LMP}_{\text{ARR Source}})$$

11.1.2 How are ARRs settled?

As detailed in PJM Manual 06,[215] the daily ARR settlement value is calculated based on the clearing prices resulting from each round of the Annual FTR auction. For each round, ARR holders will receive the revenues resulting from the price difference between ARR sink and source multiplied by the total MW amount of ARRs, divided by the number of rounds in the Annual FTR Auction. For example, if an LSE has been awarded 400 MW of ARRs on a specific path, then each 100 MW (derived by dividing the 400 MW by four rounds) will be assessed by the CLMPs emerging from each round the annual FTR auction. However, ARR holders' Credits[216] also depend on the funds collected from the Long-Term auctions and Monthly FTR auctions. ARR deficiencies from the annual FTR auction will be covered initially by the Long Term and Monthly auction revenues in proportion to the holder's deficiencies. The remaining revenues are accounted for as Excess Congestion Charges.

As illustrated in Figure 61, once the ARR target allocations are determined (Step 1), they are added and compared with FTR auctions' total revenues (Step 2). All ARR holders would get ARR

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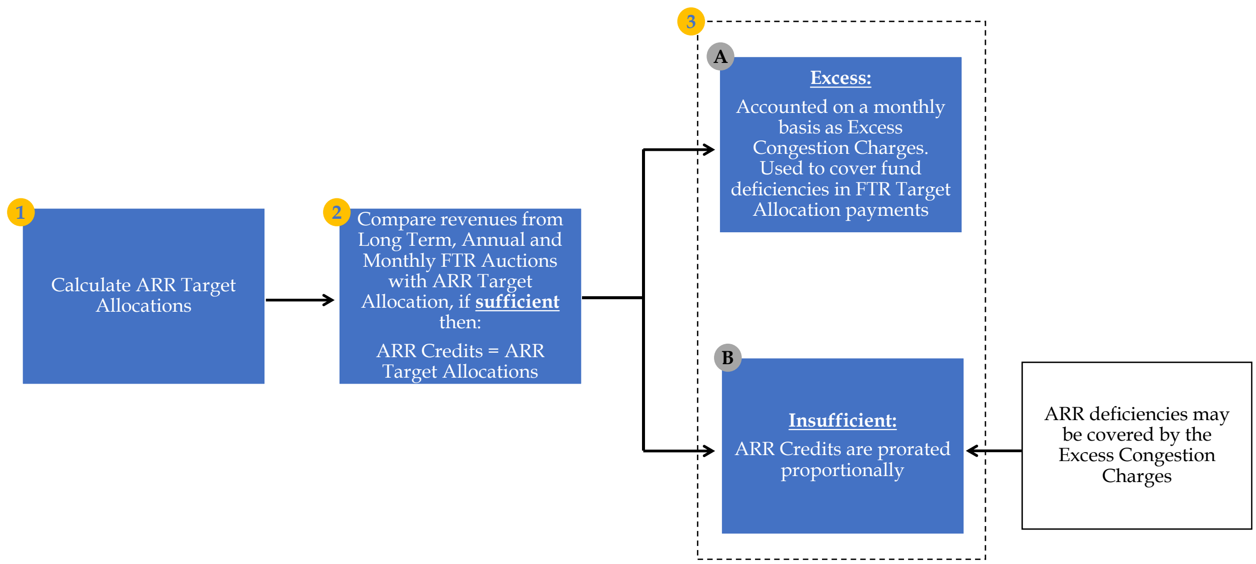
[214] PJM. "PJM Manual 6: Financial Transmission Rights." p. 28.

[215] PJM. "PJM Manual 6: Financial Transmission Rights." pp. 29-50.

[216] ARR credits are the actual revenue that the ARR holder will receive. They can be positive or negative, ranging from zero to the ARR target allocation.

Credits equal to their ARR target allocations if the funds accumulated are enough to satisfy all ARR target allocations. If there are excess funds (Step 3.A), ARR holders will also receive a payout equal to their ARR target allocations, but the remaining funds will be accounted for every month as Excess Congestion Charges. This surplus could be used to cover deficiencies in FTR target allocation payments. On the other hand, if the funds are insufficient (see Step 3.B)—as a result of all FTR auctions revenue being lower than the maximum payout for ARRs—the ARR Credits will be reduced proportionally. The Excess Transmission Congestion Charges may cover these ARR deficiencies.

Figure 61. ARR settlement process



Source: PJM training materials.

11.1.3 Incremental ARRs

IARRs were implemented in 2003 when PJM first introduced the ARR allocation process. IARRs were created for market participants who developed (and paid for) new network capacity, such as when the system expands to accommodate a generation interconnection project or a merchant transmission project.[217] The purpose of IARRs is to provide security for the participant investing in transmission, ensuring that they would receive ARR benefits that match their transmission capacity and prevent potential congestion charges.[218] The IARRs requests are not tied to a specific

[217] PJM Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM, 2007." March 8, 2008.

[218] Some stakeholders have argued that the current IARR mechanism is not working as intended. For example, generation interconnection upgrades are usually not feasible and RTEP projects are too strict to create new IARRs. Therefore, load is paying for network upgrades but not receiving the commensurate benefits. In addition, no IARRs were awarded since 2016, mainly due to their inability to pass the SFT. As such, requestors, would in theory, seek to upgrade transmission capability to ensure that the IARRs could pass the SFT. However, IARR requestors have also dropped their customer funded IARR request (where the customer

date or schedule (like the ARR allocation period). Instead, IARR requests are based on the date of a market participant's request. If approved, IARRs will be available and included in the annual ARR allocation before Stage 1A. The simultaneous feasibility of any requested IARRs is evaluated through PJM's IARR Market Models, which use the same network model used in the annual ARR allocation process, except that all transmission outages are not considered.[219, 220]

Awarded IARRs are effective for up to 30 years or equivalent to the life of the project. Should the market participant decide to replace the incremental ARR, they could do so at any point during the 30 years when the incremental ARR is effective. By doing so, they would be allocated an ARR with new values during the next annual ARR auction. This option exists so that an IARR holder can have the flexibility to acquire an alternative ARR path for its project in the future, in case the previously awarded IARR path becomes a liability.

11.2 FTR mechanisms

The conceptual definition of an FTR product has stayed the same since its inception, but the range of time-of-use FTR products and auctions has evolved (in fact, expanded) since 1998. The FTR characteristics that are currently supported are the following.

- ***obligations and options***: FTR obligations are defined by the source and sink points and are directionally specific, in that the settlement is based on the difference between the day-ahead energy market CLMP for the sink and the source. The value of an FTR obligation can be positive or negative. In contrast to FTR obligations, where the holder is liable for any negative congestion charges, the value of an FTR option to its holder can never be negative. FTR options would have a value of zero if their designated path is against the congested flow.[221] Because of this reduced risk profile, FTR buyers would typically pay a premium for the FTR options compared to an FTR obligation.[222] Additionally, FTR options are only available for a subset of the possible FTR transmission path because it is only offered to the extent that there is a residual network capability.

agrees to fund the upgrades necessary to support their request) when notified of the number violations they would have to resolve in order to attain approval.

[219] PJM. "PJM Incremental Auction Revenue Rights Model Development and Analysis." June 12, 2017.

[220] Since transmission outages change yearly, PJM removes all outages when determining requested IARRs to understand their impact on existing ARRs based on the full capability of the transmission system. As such, by removing the transmission outages, PJM would be able to determine if there needs to be an increase of system capability to grant the requested IARRs.

[221] FERC. 102 FERC ¶ 61,276. Washington DC, 2003. p. 14.

[222] PJM. PJM FTR Group. "Financial Transmission Rights Market Review." April 2020.

The source and sink points for FTRs are limited to available hubs, zones, aggregates, generators, and interface buses. Finally, FTR products are offered as on-Peak, off-Peak, and 24-hours (as described in Figure 62).

Figure 62. FTR products by time of use

Source: PJM. PJM Manual 06: Financial Transmission Rights. p. 41.

Note: PJM only allows a subset of paths to be eligible for FTR Options bids. A list of these valid option paths is available on PJM's website. See https://www.pjm.com/markets-and-operations/ftr.aspx

11.2.1 FTR Auctions

Currently, there are four pathways to acquire FTRs in PJM. Three pathways are through PJM-administered auctions: the long-term auction, annual FTR auction, monthly FTR auction (also known as the BOPP auctions). PJM also permits FTR holders to trade bilaterally so that an FTR can be acquired on the secondary market.

Annual FTR auctions are multi-round and offer multiple classes of FTRs. The capability sold in the annual FTR auctions is supposed to represent the entire system's capacity minus the approved long-term FTRs. There are four rounds in the annual auction, where 25% of the feasibility FTR capability of the PJM system is awarded in each round. FTRs that are acquired in one round may be re-offered for sale in later rounds. FTR products sold in the annual auctions include FTR obligations and FTR options,[223] and there are separate classes of products for on-peak, off-peak, and 24-hour FTRs (as described in the figure above).

Before the first round of the Annual FTR Auction occurs, LSEs have the option to convert one or more of their ARR obligations into annual FTR obligations (i.e., only 24-hour FTR obligation) on the same path as the awarded ARRs. This is called self-scheduling. For each round of the annual FTR auction, self-scheduled ARRs will clear 25% of the requested volume as price takers.

[223] Options are only available for selected paths.

Long term FTR auctions primarily aim to allow market participants to buy "residual system capability".[224] Like the annual auctions, LT FTR auctions are multi-round. The five rounds[225] for the LT FTR auction are spaced months apart, currently every March, June, August, October, and December. Like in the annual auction, LT FTRs bought in one round may be sold in successive rounds. Each LT FTR auction round sells FTR products for three consecutive planning periods after the planning period during which the Long-term FTR auction is conducted. The capacity allocated in the LT auction will be unavailable in the following annual FTR auctions. Only FTR obligations for on-peak, off-peak, and 24-hour FTRs are provided in the long-term FTR auction. Future transmission upgrades (i.e., for an increase in transmission capability) are determined only for SFT purposes in the long-term auction; the capacity is not sold to market participants in the LT FTR auction.

PJM also hosts monthly FTR auctions, where the remaining FTR capability is traded after the annual and LT FTR auctions are concluded. Market participants can also sell their previously acquired FTRs. Similar to the annual FTR auction, the monthly auctions offer both the FTR obligation and FTR options (for selected path) for on-peak, off-peak, and 24-hour FTRs. There is only one round in each monthly FTR auction.

The secondary market allows bilateral trading to increase liquidity in the market where firms can buy and sell their FTR products. However, the FTR products should be the same as the original FTR awarded (i.e., an FTR option can only be traded as an FTR option). PJM's FTR Center facilitates the trading of existing FTR between PJM members. In the secondary market, an FTR can be split into different FTRs in the same path with various MW amounts and different start and end dates.[226] However, the FTR cannot be changed to increase total MW value, set earlier start time or later end time, or use a different path.[227]

Like the ARRs, all FTRs sold need to be simultaneously feasible, so that PJM is reassured that they have not oversold capacity on the network. The SFT involves all concurrently requested FTRs and previously awarded FTRs. Therefore, newly requested FTRs are run through yearly and monthly period network models. If the newly-requested FTRs pass the model, they will be awarded to the highest bidder. All members of PJM can participate in any FTR auctions or secondary trading.

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[224] The residual system capacity is the difference between the ARR cleared in the previous year (with the ARR resulting from re-running the SFT assuming no outages), and the ARR requested in the last year.

[225] Prior to April 2020, there were only three rounds in the LT FTR auction.

[226] PJM. "PJM Manual 06: Financial Transmission Rights." p. 47.

[227] Ibid.

11.2.2 How is the economic value set for FTRs?

The economic value of FTRs is akin to the profit of holding the FTR. Profit is the difference between the price the FTR buyer has to pay PJM in the FTR auction[228] and the congestion charges it will earn once day-ahead LMPs (specifically, CLMPs) are determined. The FTR target allocation is the maximum amount of money that the FTR holder would receive if the congestion charge is positive for an FTR obligation or FTR option, or the amount it has to pay if the congestion charge is negative for an FTR obligation. Figure 63 shows how FTR target allocations are calculated. An uplift charge might affect this profitability[229] if there are any revenue deficiencies with ARRs or FTRs at the end of the planning period.

Figure 63. FTR target allocation

$$\text{FTR Target Allocation} = (\text{FTR MW}) \times (\text{Congestion Price}_{\text{FTR Sink}} - \text{Congestion Price}_{\text{FTR Source}})$$

11.2.3 How are FTRs settled?

The FTR settlement is calculated hourly based on the CLMPs determined in the day-ahead energy market.[230] CLMPs track the hourly congestion component of LMPs across the entire RTO footprint at a given moment, based on a selected reference bus. The CLMP at a specific node is meant to represent the economic impact of all binding transmission constraints on the delivery of energy to that specific location. Once the FTR target allocations are determined (Step 1), PJM compares them with the total congestion charges collected from the day-ahead energy market (Step 2) (Figure 64). If the amount of revenues (sum of Day-Ahead Congestion Charges) collected is sufficient, then the Day-Ahead Congestion Credits[231] for each FTR is equal to its own FTR target allocation. If the amount of revenues exceeds the FTR target allocation (Step 3.A), then the Day-Ahead Congestion Credits for each FTR (also known as FTR Credits) is equal to its own target

[228] Self-scheduled ARRs do not incur a charge for the acquired FTR. ARR holders are essentially "paying" for the FTR by giving up the FTR auction revenues for that path.

[229] An uplift charge is the charge to cover the net of the monthly deficiencies in the target allocations calculated for individual participants.

[230] PJM. "PJM Manual 6: Financial Transmission Rights." pp. 50-52.

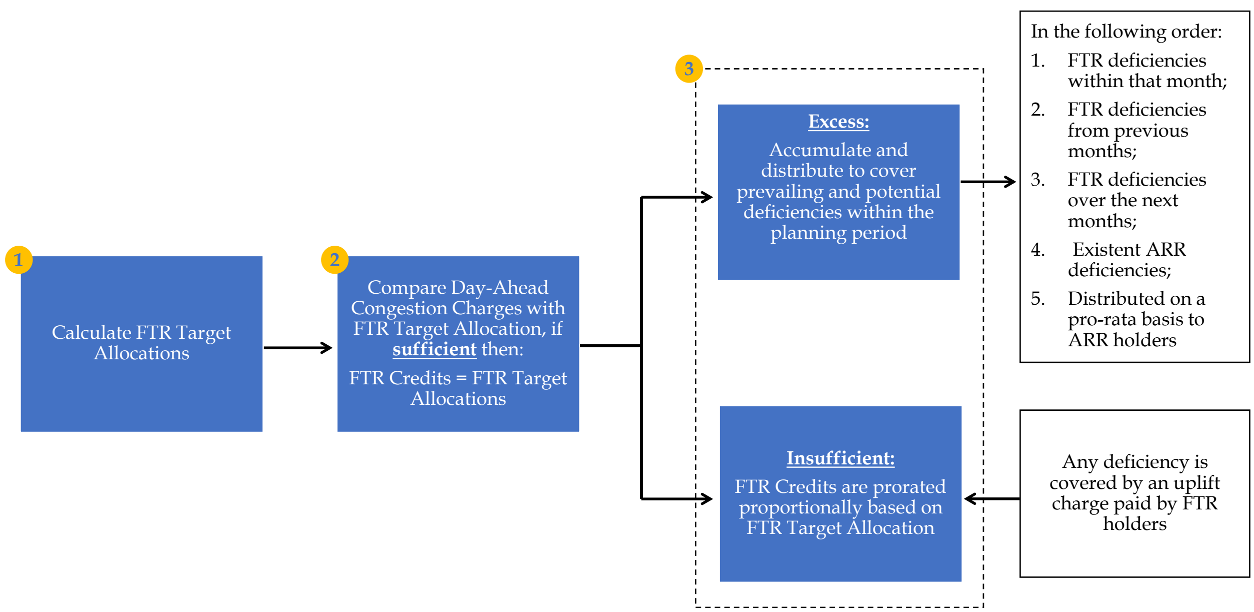
[231] Day-Ahead Congestion Credits are the actual revenue that the FTR holder will receive. They can be positive or negative, ranging from zero to the FTR target allocation.

> ***Why can FTR funding insufficiency occur?***
>
> FTR Funding may be insufficient due to various factors such as increased limits utilized in FTR model due to Stage 1A ARR infeasibilities, reduced transmission capability in day-ahead energy market due to transmission outages that were not represented in the network model used to do the SFT during the FTR auction, or due to loop flows or uncompensated flow impact and de-ratings.

allocation, and the excess is earmarked to cover the prevailing or potential deficiencies of other FTR paths within the planning period.

Initially, PJM uses the excess to cover deficits among FTR holders during the same month. If funds are remaining, then PJM proceeds to cover other shortfalls in the following order: FTR deficiencies from previous months, FTR deficiencies over the next months, and then any existing ARR deficiencies. Finally, if some funds remain, these excesses are rolled into surplus congestion and distributed on a pro-rata basis to ARR holders based on their relative positive ARR target allocation position.

Figure 64. FTR settlement process

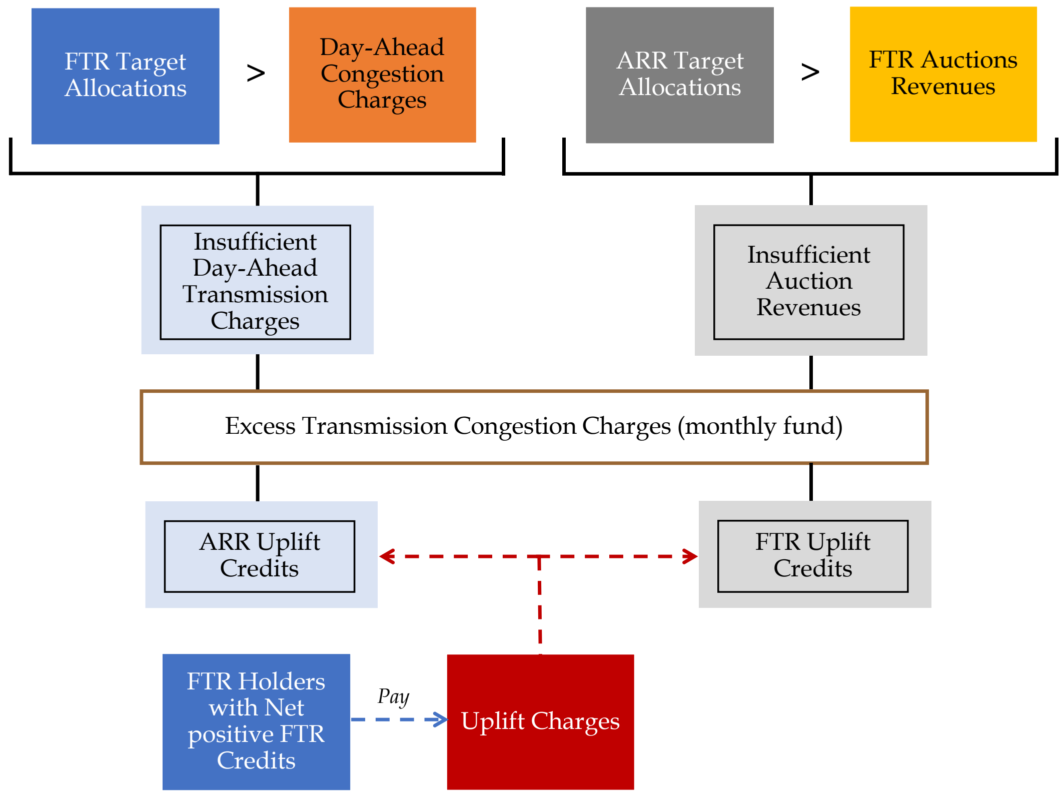


Source: PJM Workshop.

On the other hand, if the FTR funding is insufficient to cover the FTR target allocations (Step 3.B), only FTR holders with a total target allocation position that is a net negative for the hour receive Day-Ahead Congestion Credits equal to its own target allocation. FTR holders with a net positive total target allocation position for the hour receive a portion of the total Day-Ahead Transmission Congestion Charges and net negative target allocation positions. If there are insufficient funds to cover all FTRs, then an FTR holder with a net negative position (liability) will have to pay all his charges to PJM, while an FTR holder with a net positive position (credit) will receive only a share of the day-ahead congestion funds collected.

PJM covers any prevailing not fully funded ARR or FTR target allocation through an uplift charge socialized across all FTR holders with net positive positions at the end of the planning period. An illustration of the uplift mechanism is presented below.

Figure 65. Uplift mechanism



PJM allocates the Day-Ahead Transmission Congestion Charges to FTR holders based on their total FTR target allocations. If at the end of the planning year (i.e., May 31st), the congestion charges are not sufficient to fulfill all FTR target allocations, uplift credits (i.e., the dollar amount needed to get the total FTR target allocation) are awarded to cover these revenue deficiencies for FTR holders. Uplift credits will also be applied to any ARR holder which ARR target allocation has not been fully funded by the revenues collected from FTR auctions by the end of the planning year. It is worth mentioning that before PJM calculates the required uplift credits, it uses any Excess Congestion Charge remaining in its monthly fund to clear partially or totally these ARR and FTR deficiencies.

The uplift credits that act as a "make-whole" payment will be covered by an uplift charge only paid by FTR holders with net positive FTR target credits. In other words, the uplift charge required to balance out any ARR and FTR deficiency (i.e., uplift credit awarded) will be socialized among FTR holders with a net positive position.[232] Figure 65 illustrates the process of the uplift mechanism. The formula that determines how the cost of providing these uplift credits will be split among this specific set of FTR holders is shown in Figure 66 below.[233]

Figure 66. Uplift charge

Uplift Charge	=	(Positive FTR Target Credit / Total Positive FTR Target Credit)	X	Total FTR and ARR Uplift Credit

[232] According to Section 8.5 of the PJM Manual 6, "an entity with a net negative FTR target allocation position is not subject to transmission rights uplift allocation charges and are excluded from the uplift charge calculations." PJM. Guide to Billing. Website. Accessed on November 25, 2020.

[233] PJM. Guide to Billing. Website. Accessed on November 25, 2020.

12 Appendix D: Stakeholder engagement

To conduct a holistic assessment of PJM's ARR and FTR mechanism and to determine if load is receiving the optimal value of the transmission system, LEI engaged with PJM market participants to acquire a better understanding of the ARR and FTR products from their perspective. Furthermore, the discussions with stakeholders allowed LEI to analyze market participants' hands-on experience of the ARR and FTR market. The stakeholder process contributed to LEI's understanding of the current ARR/FTR design (Task 1) and provided conceptual ideas for enhancements that LEI analyzed (as part of Task 3). This Appendix provides an overview of the stakeholder engagement process as well as LEI's key observations.

From the stakeholder engagements, LEI observed that many ARR participants and FTR auction participants were generally satisfied with the current ARR/FTR design and would prefer to have minor improvements and enhancements rather than a complete overhaul.

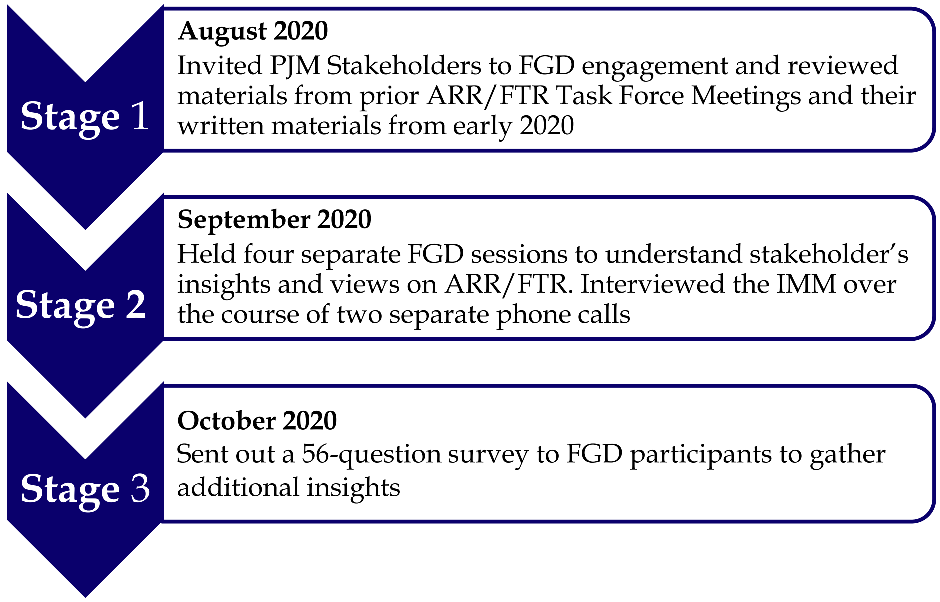
On the ARR allocation process, LSEs were appreciative of the recent changes made by PJM to prevent underfunding. Nevertheless, several LSEs and representatives of LSEs voiced a strong interest in seeing further improvements to the ARR allocation process. For example, some stakeholders suggested more frequent ARR allocations and nomination periods and more granular ARR products that are more closely aligned with the range of FTR products currently available.

With respect to the FTR design, most FTR buyers and traders were happy with the FTR products' granularity and the frequency of the auctions. Non-LSEs (or the financial participants) were generally satisfied with the FTR market and felt their commercial objectives were being met. The majority agreed that the FTR market provides sufficient price discovery for the forward market and superior hedging opportunities. When asked about the competitive nature of FTR auctions, there was consensus that the auction outcomes were competitive, although some concerns were raised regarding the overly mitigative nature of the existing forfeiture rule. LSEs and other stakeholders acquiring FTRs for hedging also suggested that the FTR products could evolve to better meet the needs of intermittent energy sources, which operate in periods that may not align with traditional peak and off-peak designations.

12.1 Overview of the stakeholder engagement process

LEI led a series of FGDs with stakeholders who participate in or are involved with ARR and FTR markets. The purpose of these FGD sessions was to understand various stakeholders' insights given the diverse roles they have in the markets (e.g., end-use customers or LSEs that get allocated ARRs, FTR buyers, to name a few). Additionally, LEI sent out a follow-up survey to the FGD participants and interested stakeholders with additional questions. The engagement process started in August 2020 and was split into three stages over several months, as shown in Figure 67 below.

Figure 67. Stages of LEI stakeholder engagement



PJM emailed a survey on August 31, 2020, gauging interest in a stakeholder engagement from members of the ARR/FTR Task Force and the Market Implementation Committee.[234] A total of 37 stakeholders (in addition to the IMM)[235] expressed interest and availability to join the focus group discussions (FGDs). The respondents self-identified as one of the four categories that most represented their activity or involvement in the ARR/FTR Market:

(i) FTR participants,
(ii) ARR Awardees,
(iii) mixed-use participants (ARRs and FTRs), and
(iv) others (entities who do not trade or interact directly with PJM's ARR process and FTR market).[236]

Using the groupings above, LEI scheduled four FGD sessions.[237] Although the participants were categorized based on their involvement in the ARR and FTR market, they represented many segments of the PJM stakeholder universe, including vertically integrated utilities, municipally-owned utilities, cooperatives, competitive LSEs, generation owner, power marketer, end-use

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[234] Email Correspondence with PJM on November 5, 2020. According to PJM, the email was sent to 1,098 stakeholders.

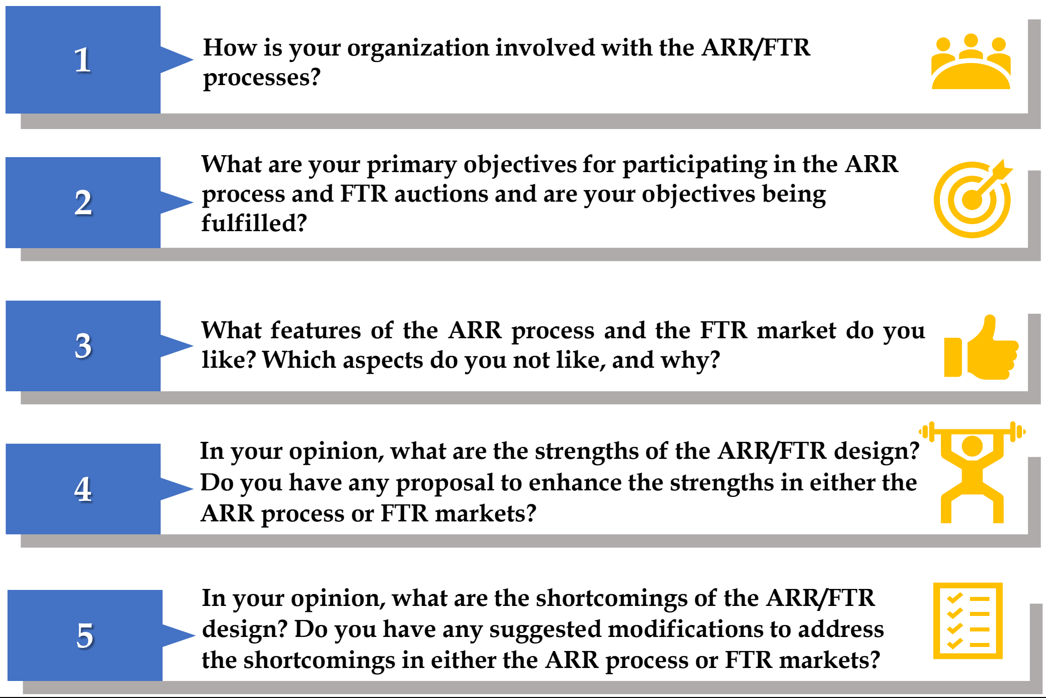
[235] LEI interviewed the IMM separately.

[236] Email Correspondence with PJM, August 31, 2020.

[237] Since there were only 2 entities that identified themselves as ARR awardees, they were included under the Mixed-Use Participants group.

consumers, power traders, consultants, and advocates. Each FGDs was scheduled for three hours. Five key topics, as shown in Figure 68, were discussed during these sessions.

Figure 68. Topics discussed in the FGD



To ensure that each participant has an equal opportunity to speak up and provide their insights on the five topics, LEI allocated a pre-set amount of time for each stakeholder representative to answer each question during the FGDs. LEI also invited additional commentary at the end of each FGD.

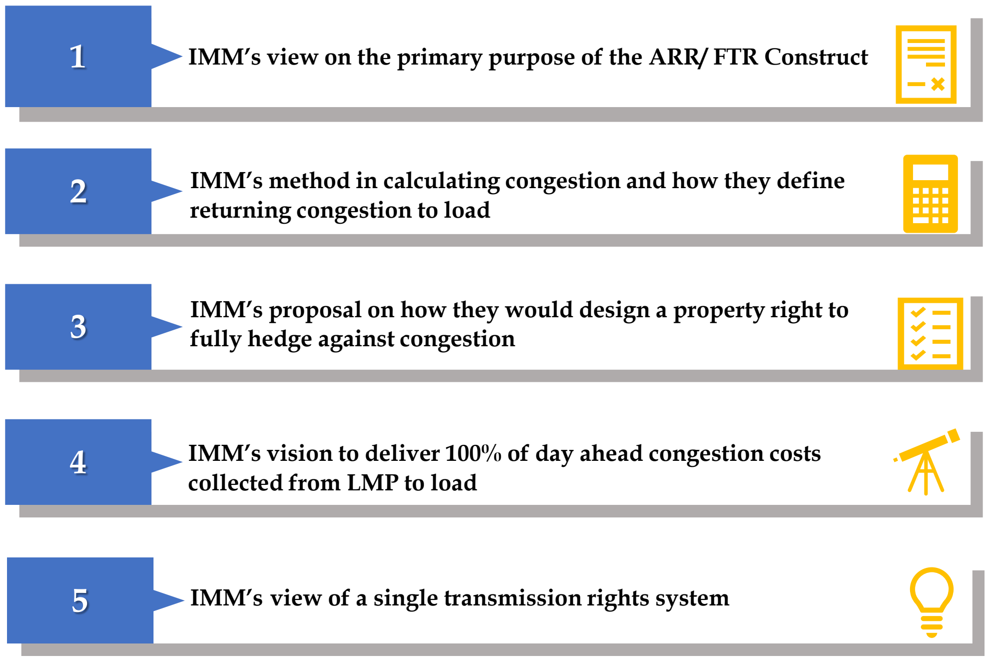
Following the FGDs, several stakeholders reached out to LEI through email to provide additional feedback. To ensure comprehensiveness of the stakeholder input process, LEI also accepted "out of time" feedback and commentary.[238]

Separately, LEI interviewed the IMM via several conference calls to gather the IMM's insight and perspective on the current ARR/FTR design and better understand the IMM's conceptual proposal. The major areas of discussion are shown in Figure 69. Also, LEI sent IMM a list of questions (19 questions) as a follow-up to the interviews.

In addition, LEI also met with ICE and Nodal Exchange to better understand how PJM's FTR markets affected the futures trading on their separate exchanges.

[238] LEI received written comments from several stakeholders in conjunction with the third stage.

Figure 69. Areas of discussion with IMM



In the third stage of the stakeholder engagement, LEI sent out a follow-up survey to FGD participants and other interested stakeholders[239] in early October 2020 to gather additional information and feedback on the ARR allocation process, FTR products and auctions, application of current rules (like the forfeiture rule), and identification of business decisions that were affected by ARRs and FTRs. The survey was voluntary, and participants were not required to answer all the questions. Nevertheless, LEI received significant cooperation with the completion of the survey by stakeholders, as discussed further in Sections 12.4 and 12.5.

12.2 Key takeaways from FGD sessions in September 2020

The majority of the participants were generally satisfied with the current ARR and FTR mechanisms in PJM. There was widespread recognition that the rules have continuously adapted over the past twenty years. Most participants welcomed the majority of rules changes; however, there was a level of concern expressed by the frequency of rules changes pertaining to ARRs and FTRs in PJM in recent years and ongoing disputes. Despite the general sense of fatigue with evolving market rules, participants did not shy away from suggesting enhancements and identifying areas of improvement.

[239] PJM sent an email to the stakeholders on September 30, 2020 to inform them about the survey.

12.2.1 FGD participant's primary objectives for participating in the ARRs and FTRs

- **Views of non-LSEs (Financial Participants):** The majority of non-LSE participants agreed that their objectives are being met with the current ARR and FTR structures, but they also stated that there are several areas that could benefit from improvement. As many of the Non-LSEs are commodity traders within the electricity market, they were particularly interested in changes that would increase liquidity and trading opportunities and improve the price discovery process originating in the FTR auctions. One specific stakeholder remarked that, while their objective to participate in the FTR auctions is find valuable FTRs, they often purchased FTRs for other reasons (for example, to hedge their basis trades on the exchanges).

- **Views of LSEs (Mixed Use Groups):** The LSEs widely agreed that their objective for using ARRs is to maximize the return of congestion costs. Additionally, they mentioned that their objectives for participating in the FTR auctions are to hedge congestion risk and mitigate price spikes. Some LSEs also utilized FTRs to manage basis risk. While many of the LSEs felt that their objectives are being fulfilled, they also indicated that the ARR mechanism could be further enhanced. Additionally, some LSEs stated that they felt that the value of ARRs allocated to them has decreased (with time), which detracted from the primary objective noted above.

- **Views from the Others Group**: Although the Others Group comprised stakeholders with various roles, they generally agreed that the primary objective for ARRs/FTRs is to maximize the transmission network's value and return congestion charges to load (final customers), who were also paying for transmission service through regulated rates. Among the Others Group, one participant also added that a secondary objective for utilizing FTRs is to support clean energy goals.

12.2.2 FGD Stakeholder's view on the strengths and weaknesses of ARR and FTR mechanism

- **Views of non-LSEs (Financial Participants):** Although financial participants mentioned that the ARR/FTR mechanism in PJM could benefit from further improvements, they favored the current mechanism for its ability to provide adequate price discovery, support liquidity and thereby facilitate competition in the forward markets, which increases the efficiency of the forward market price signal. Furthermore, they found the FTR mechanism useful for hedging. Non-LSEs also stated that they appreciate the increase of FTR granularity over the years. However, they believe that FTRs could be further enhanced.

  Non-LSEs also noted three weaknesses with the current ARR and FTR constructs. The first point of concern was the lack of transparency for FTR auction data and outage modeling. Secondly, they felt FTR activity had been unduly constrained by the FTR forfeiture rule. The current forfeiture rule (implemented in 2017) is not sufficiently parsimonious and therefore forces them to choose between trading in the FTRs and virtuals. Thirdly, they expressed an interest in seeing adjustments to credit rules so that the requirements do not become overly burdensome, inhibiting liquidity and price discovery. Finally, non-LSEs also mentioned that the constant rule changes and the contentious nature of the stakeholder process have made it difficult for them to plan in the long-run, as they are not confident that the current rules will remain. Overall, non-LSEs expressed a preference for the status quo and opposed significant changes to the conceptual design of FTRs.

- **Views of LSEs (Mixed Use Groups):** LSEs commented more on the ARR process than on the FTR auctions. During the engagement, LSEs stated that they appreciate the current FTR mechanism. There was also widespread recognition that Stage 1A of the ARR allocation process helped guarantee some level of "hedge" each planning year. Specifically, LSEs saw the certainty and predictability of Stage 1A and the consistent timeliness of how ARRs are allocated annually and auction revenues from FTR auctions paid out to ARR holders as strengths of the existing design. Furthermore, LSEs echoed non-LSEs' support for the increasing granularity of the FTR product and auction cycle, as well as the rule changes to combat underfunding. Nevertheless, LSEs believed that there could be further improvements – namely, greater product granularity for both ARRs and FTRs.

  Although LSEs expressed general satisfaction with the current mechanisms, some LSEs questioned whether they were receiving the full congestion value of the network. The first concern comes from the quantity of network capacity allocated. Some felt that ARR allocation using historical paths did not accurately capture the paths that they used and the flows on the current system, and that diminished the value of the ARRs they were allocated. Furthermore, LSEs felt that the availability of ARR products was limited in comparison to FTRs. For example, ARRs are only available as obligations, while FTRs can be acquired (for some paths) in option format. ARR allocation is only conducted once a year, while there are multiple opportunities to buy and sell FTRs throughout the year. In essence, some participants used these distinctions to conclude that there is an inconsistency between the two property rights, which reflects negatively on the ARRs given to load and other firm transmission customers. Also, LSEs felt that the current 24-hour nature of ARRs and the level of FTR granularity did not account for the increasing role of renewable generation.

  Secondly, several LSEs felt that the technology for uploading FTR bids to PJM's system is antiquated and inflexible. Currently, only xml format is allowed. Some LSEs suggested that PJM evaluate the use of csv files in the future. The third concern was the participants' lack of trust in PJM's network model, specifically because of the non-transparent nature of routine changes and updates.

  Like financial participants, LSEs also disliked the current credit rules and the FTR forfeiture rule. In terms of the current credit rule, some LSEs felt that it focused too heavily on collecting collateral rather than managing risk. LSEs also believed the stringent FTR forfeiture rule prevented some of them from engaging in virtuals.

- **Views from the Others Group**: The perspective on the ARR and FTR mechanism's strengths and weaknesses from the Others Group was more diverse than LSEs and non-LSEs. Even so, many of the participants in the Other Group agreed with LSEs and non-LSEs that FTRs have helped hedge congestion and manage risk.

  In terms of the ARR and FTR mechanism's weakness, participants in the Others Group articulated similar concerns as other stakeholders, such as the inconsistency between ARRs and FTRs, and network modeling transparency. Additionally, one participant noted that the current ARR structure does not let customers get the resource paths needed for the new generation, and therefore the theoretical strength of the ARR concept is undermined.[240] In addition, the Others Group also raised two points of weakness that were not previously mentioned in the non-LSEs and LSEs group. First, one of the stakeholders expressed a belief that the FTR auction did not allow load to earn the full value of the transmission system, because the revenues from the auction are below "value".[241] Second, another stakeholder suggested that in his view the FTR construct had become attractive to participants such as speculators, which increased the risk of default and detracted from the original purpose of FTRs.

12.2.3 Enhancements and modifications on the ARR and FTR mechanism, based on FGD Stakeholder's statements

In discussing the ARR and FTR mechanisms' strengths and weaknesses, as mentioned above, FGD stakeholders proposed a number of enhancements and modifications to the current ARR and FTR mechanisms. Proposed enhancements to the ARR/FTR design include:

- greater ARR allocation frequency, from an annual to a seasonal or monthly basis. Some participants also suggested that the ARR product be more granular on an hourly basis than the current 24-hour product;
- instituting reservation prices on FTRs; and
- increasing the granularity of FTR products, with the most commonly suggested change being the addition of off-peak weekday and off-peak weekend FTR products.

In addition, stakeholders also had three other suggested modifications:

- improvement in modeling outages within the network model;
- revision of the current credit rules;[242] and
- relaxation of the current FTR forfeiture rule.

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[240] FGD Stakeholder Engagement, September 22, 2020.

[241] Ibid.

[242] See footnote 2.

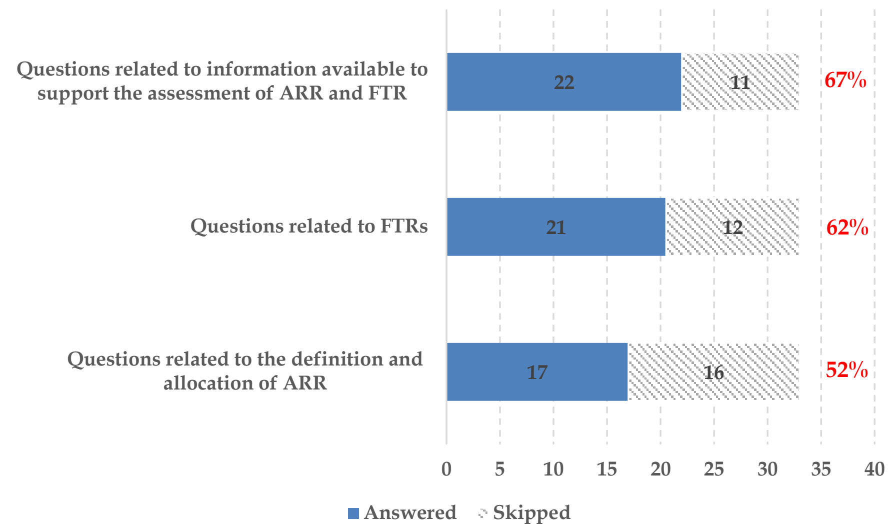
12.3 Insights from the questionnaire survey

Following the FGD sessions in September 2020, LEI sent out a questionnaire survey to gather additional data from stakeholders about their involvement and use of the current ARR/FTR mechanisms. In total, the questionnaire consisted of 56 questions that were categorized into three sections: ARR allocation process, FTR product and auction, and general assessment of ARR and FTR functions. The subsections below provide a summary of the results of the survey.

12.3.1 Response rate

LEI received 33 completed (or partially completed) surveys,[243] with an average response rate of 60% for all the questions, as seen in Figure 70.

Figure 70. Average response rate for each section of the survey



Source: FGD Questionnaire Survey.

Based on the survey, each respondent self-identified their company's role (in the context of PJM markets); respondents were allowed to select multiple entries from the following choices:

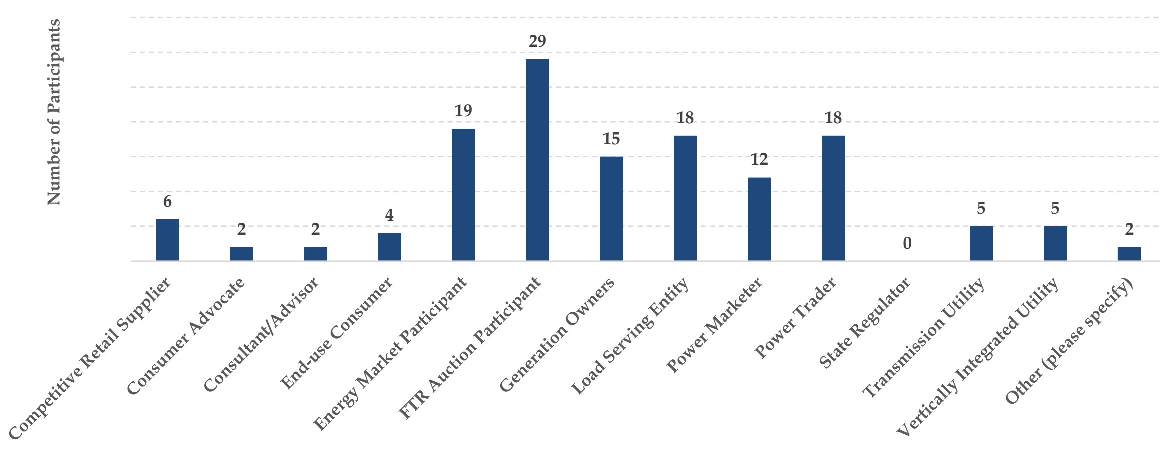
- competitive retail supplier
- consumer advocate
- consultant/advisor
- end-use consumer
- energy market participant

[243] Note that while there were 41 FGD participants, a few of them represented the same organizations, and as such, they consolidated their answers, resulting in 33 completed (or partially completed) questionnaire.

- FTR auction participant
- generation owners
- load servicing entities
- power marketer
- power trader
- state regulator
- transmission utility
- vertically integrated utility

Other than FTR auction participants, the four most common roles selected by survey respondents included: energy market participant, power trader, generation owners, and LSEs, as illustrated in Figure 71. Although there was a total of 33 respondents, only 29 identified themselves as FTR auction participants. Those who did not indicate the FTR auction participant roles were either consultants, consumer advocates, or generation owners who do not participate in FTR Auctions.

Figure 71. Breakdown of participants in the questionnaire survey

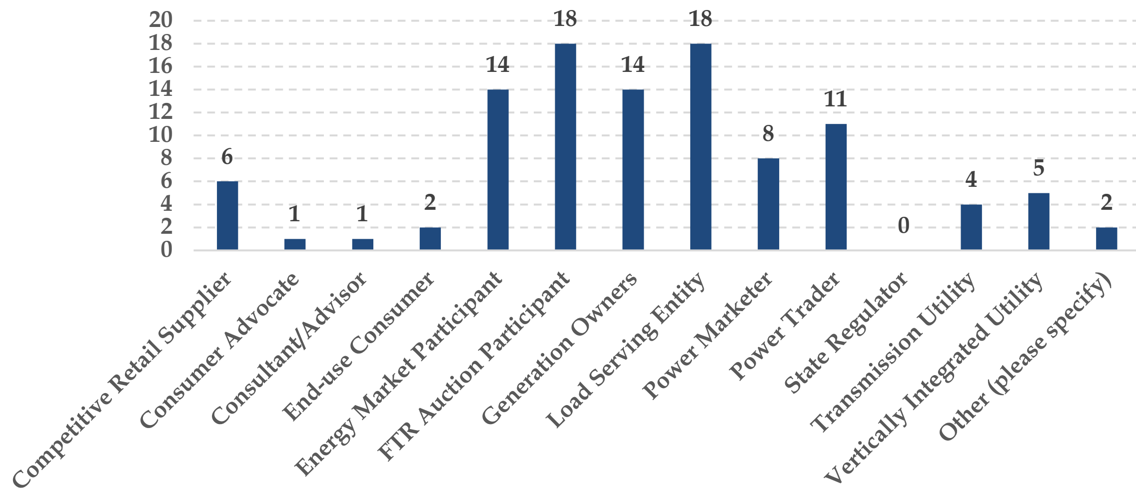


Source: FGD Questionnaire Survey, Question 5.

The 18 respondents who indicated that they are LSEs also self-selected other roles. As illustrated below, 14 of the LSE respondents indicated that they were also generation owners and energy market participants, 11 were power traders, and 8 were power marketers. Notably, less than one-third of the LSE respondents were also a transmission utility, vertically integrated utility, and competitive retail supplier. It is important to note that the four respondents who are LSEs, but not generation owners, are either competitive retail suppliers or solely power traders (financial participants).

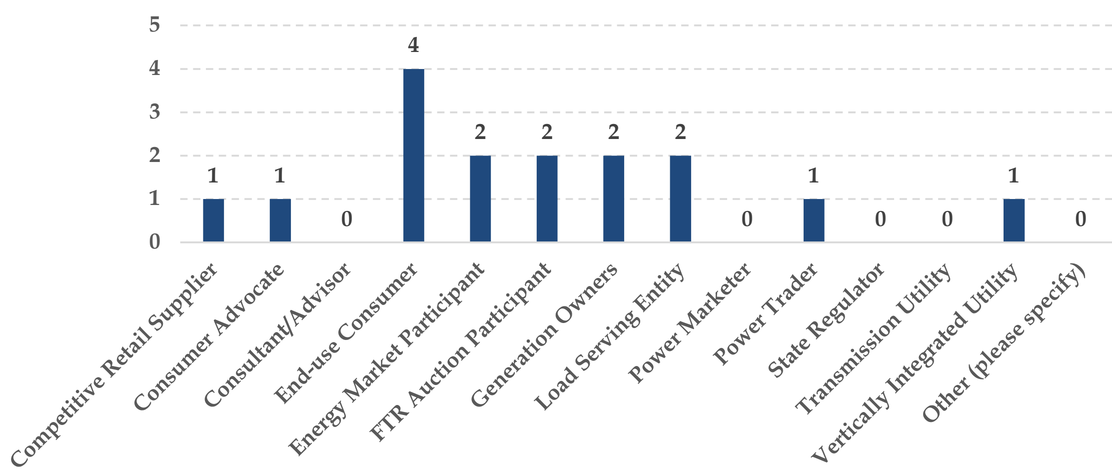
As shown in the figures below, all vertically integrated utilities were also LSEs. However, only 4 of the 5 respondents who identified themselves as transmission utility were also LSEs. The sole non-LSE transmission utility was also a generation owner and FTR auction participant.

Figure 72. LSEs self-identified in these other roles



Source: FGD Questionnaire Survey, Question 5.

Figure 73. End-use consumers self-identified in these other roles

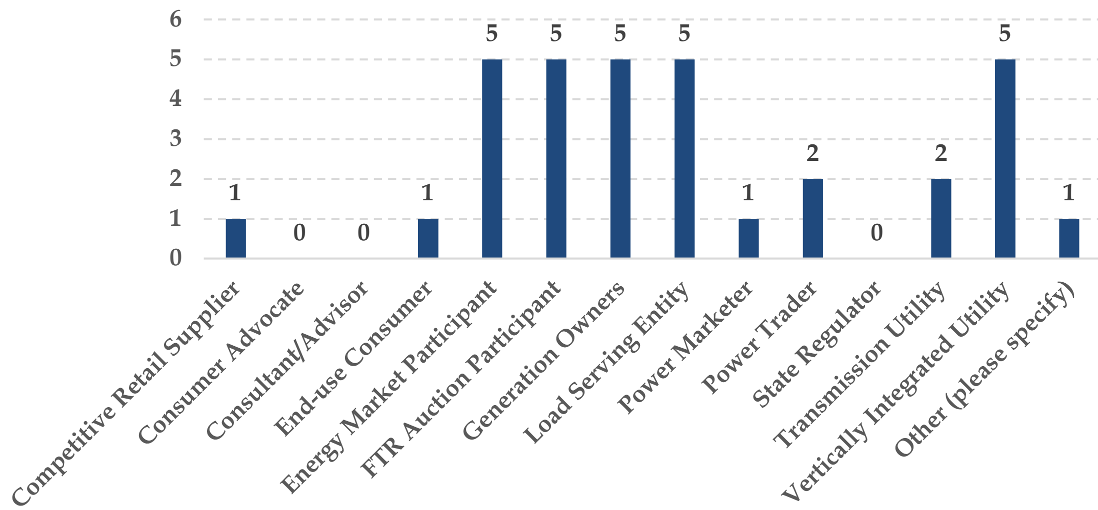


Source: FGD Questionnaire Survey, Question 5.

Of the four end-use consumers, two identified as generation owners, LSEs, FTR auction participants, and energy market participants. Among the two, only one identified as a vertically integrated utility and power trader. The remaining end-use consumers were consumer advocates.

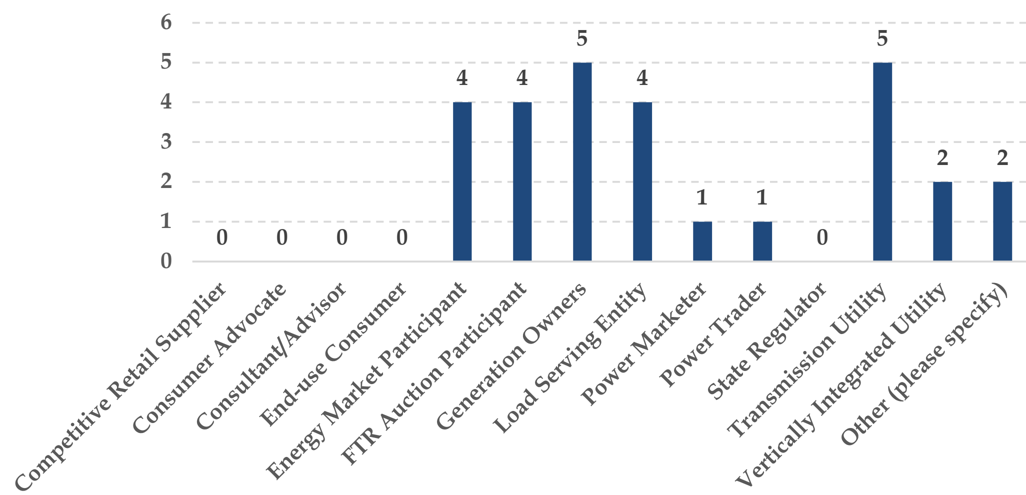
Among the 33 respondents, two also selected "Others" as their role within the ARR/FTR Market. One of the participants stated that they were also a generation and transmission cooperative. They also held the roles of transmission utility, power trader, LSE, FTR auction participant, generation owner, and energy market participant. The other participant was a power trader but stated that "their roles also varied depending on the outcomes of competitive wholesale load auctions, Request for Proposals ("RFPs"), and bilateral transactions," and as such, they decided to select "Others."

Figure 74. Vertically integrated utility self-identified in these other roles



Source: FGD Questionnaire Survey, Question 5.

Figure 75. Transmission utility self-identified in these other roles



Source: FGD Questionnaire Survey, Question 5.

12.4 Insights into the ARR allocation process

Less than half of the ARR holders were satisfied with the ARR allocation process, and only a minority felt that allocated ARRs were sufficient. In addition, although many FGD participants were interested in increased granularity with ARR products and allocation, the survey responses suggested interest only in the monthly allocation of ARR entitlements. Other potential ARR products, such as Longer-Term ARRs (in lieu of or in addition to 10-year Stage 1A) and ARRs differentiated by calendar periods, were not popular choices among survey respondents. Finally, the survey reflected that more than half of ARR holders felt that ARRs influenced their long-term strategic decisions.

12.4.1 Sufficiency vs. satisfaction with the ARR allocation process

In the survey, LEI asked that respondent comment on whether they were satisfied with the current ARR allocation process and if they felt they received sufficient ARRs. ARR sufficiency was defined as, but not limited to, the availability of allocated ARRs in terms of quantities, paths, value, and nomination frequencies. The data was collected from a multiple-choice option, where the stakeholders could choose between "sufficient and insufficient." Satisfaction was scored more simply – in terms of "yes and no" and was specific to the current ARR allocation process.

As shown in Figure 76, only four participants (19%) viewed the allocation of ARRs as sufficient, whereas seventeen (81%) felt that the ARR allocation process was insufficient. The four participants who responded that they thoughts\ that the allocation of ARRs was sufficient self-identified as LSEs, generation owners, power traders, and energy market participants. The remaining seventeen participants who viewed the ARR allocation process as insufficient were more diverse in their self-identification of roles. In the aggregate, they selected all of the fourteen roles available.

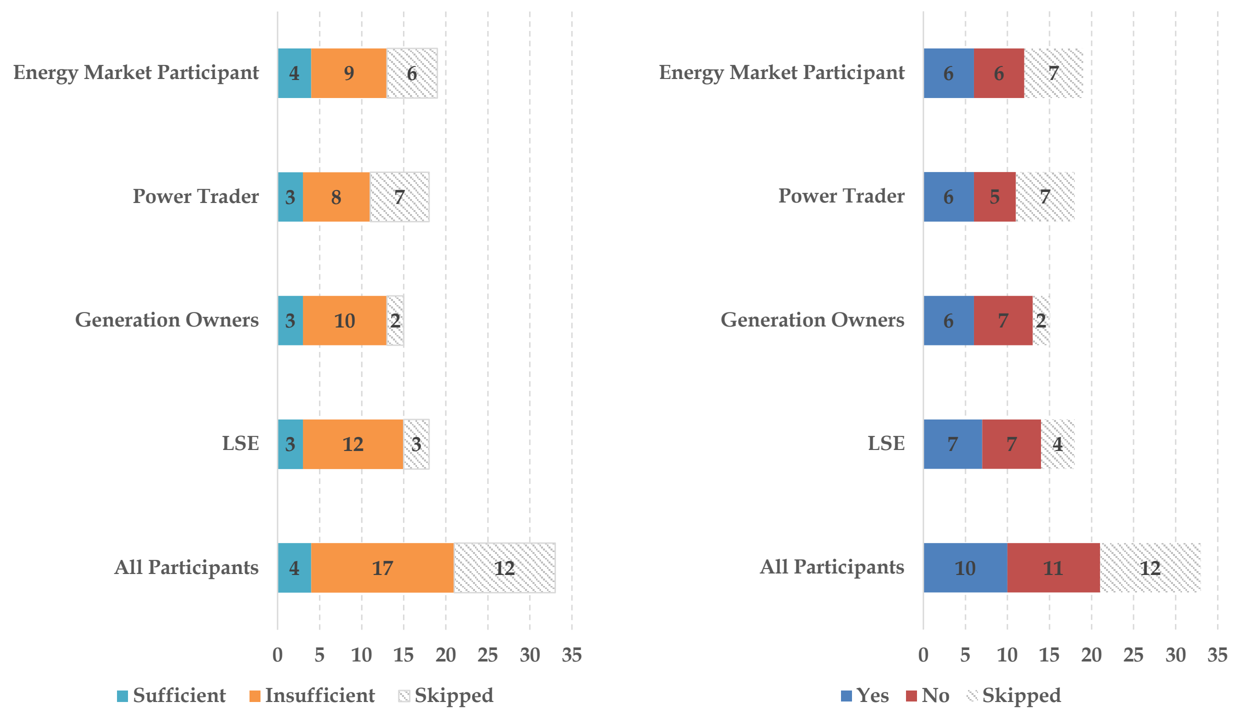
Respondents cited numerous reasons for the ARR insufficiency, with the top factors being lack of ARRs in terms of quantity, shortage of specific ARR paths, outdated allocations due to historical paths, and lack of nomination frequencies and ARR granularity. Although some respondents voiced an interest in greater ARR nomination frequency and granularity, a larger number of respondents supported having monthly ARR allocations (as further discussed in Section 12.4.2).

In total, 10 (48%) respondents felt satisfied with the current ARR mechanism, whereas 11 (52%) were dissatisfied. Some of the respondents who had said that they are "satisfied," supported their views by noting that (1) ARR allocation outcomes are predictable and well-understood, and (2) ARRs achieve the primary objective of providing hedging to load entities.[244] In contrast, the dissatisfied respondents commented that (1) the historical paths are outdated and (2) there is a zonal misalignment between congestion revenues and costs leading to under-allocation of ARRs.

[244] FGD Questionnaire Survey, Question 21.

Of the ten respondents who were satisfied with ARR allocation, only three felt that ARR allocation was sufficient. While the remaining seven were satisfied with the ARR mechanism, they felt that improvements could be done, including increasing ARR availability in terms of quantity, paths, and sub-annual tenure of ARRs. Two of the seven stakeholders thought that PJM modeling should be improved so that ARRs are not withheld.[245]

Figure 76. Stakeholder views on ARR sufficiency and ARR satisfaction



Note: Not all roles indicated in the figure are mutually exclusive. Stakeholders held several roles within PJM's ARR/FTR Market.

Source: FGD Questionnaire Survey, Questions 12 and 21.

The remaining eleven respondents who were dissatisfied with ARR allocation also indicated that they thought that ARRs were insufficient. They echoed that the ARRs lacked quantity and the ARR nomination frequency was suboptimal. Additionally, some of these respondents stated that there is a lack of value received by stakeholders.[246]

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[245] FGD Questionnaire Survey, Question 13.

[246] Ibid.

12.4.2 Views on ARR product types and granularity

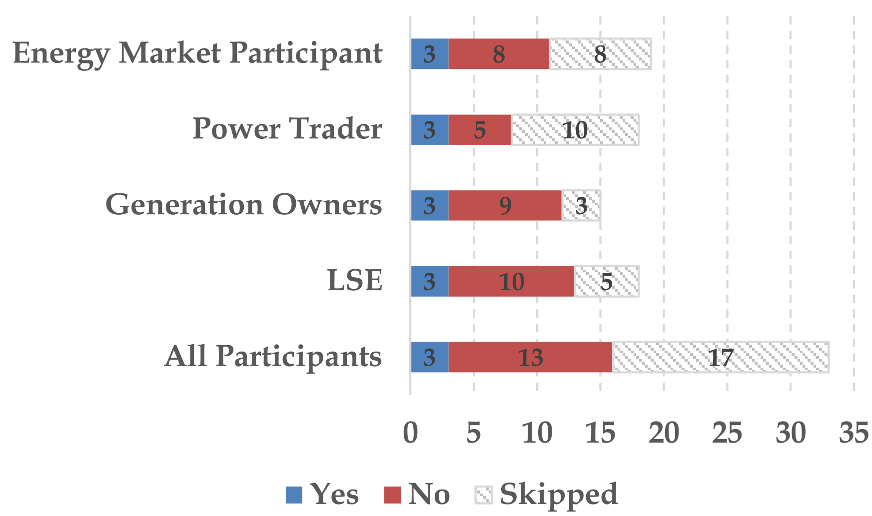
As mentioned in Section 12.2.2, during the FGDs, many stakeholders commented that they would like to see greater ARR granularity and more frequent allocation of ARRs (not just annual). However, the survey results reflected a somewhat different perspective.

Specifically, the survey gauged the interest of three potential and distinct changes to the current ARR entitlement, based on what LEI gathered initially from the FGDs. The survey elicited support for:

- issuance of long-Term ARRs;
- allocation of ARRs on a more granular basis than annual 7x24 (for example, peak versus off-peak) differentiated by time of use periods; and
- allocation of monthly ARR entitlements.

Of the three options for modifying existing ARR products, long-Term ARRs were the least popular, as only 3 (19%) of the respondents expressed positive interest, as seen in Figure 77. Based on Figure 78, more respondents preferred more granular ARRs differentiated by time of use periods (44%). Of those interested, they stated that peak and off-peak periods, as well as weekend and weekday ARRs, would help align hedges for renewable energy sources.

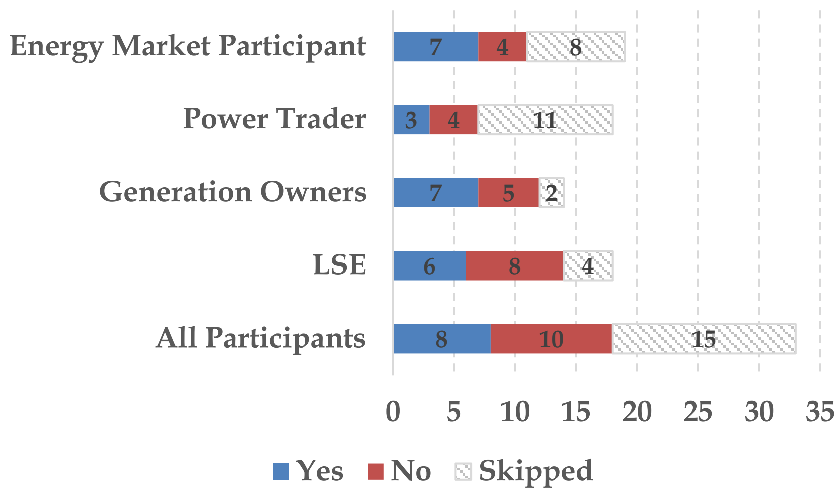
Figure 77. Interest in longer-term ARR in lieu of or in addition to 10-year Stage 1A



Source: FGD Questionnaire Survey, Question 14.

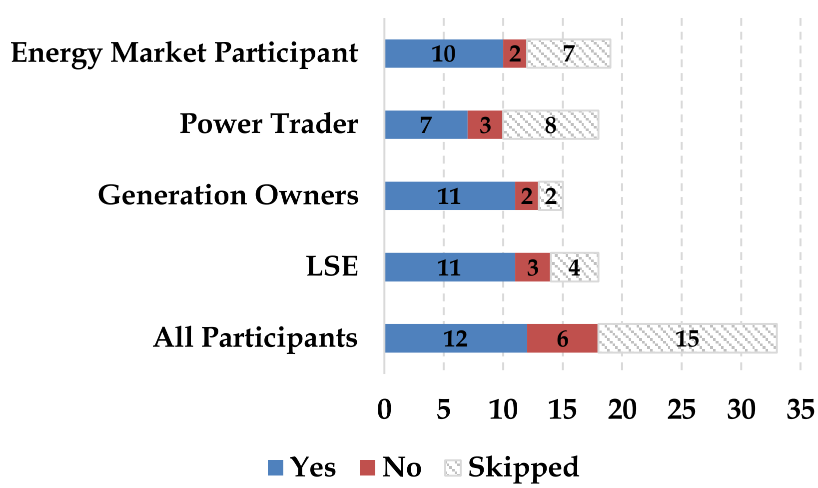
The monthly allocation of ARRs was the most popular potential change, as observed in Figure 79. In total, twelve of the respondents (66%) favored the monthly allocation of ARRs. However, there is recurring sentiment and fear that the ARRs would devalue if there were too many allocated. Several respondents that stated interest in the monthly allocation of ARRs, also noted that they would oppose it if there will be no increase in revenue from the FTR Auctions, and therefore the additional ARR products would only decrease the value of the ARRs allocated. In essence, these respondents were concerned about dilution effect, if increasing quantities of ARRs would be funded by the same amount of revenues from the FTR auctions.

Figure 78. Interest in ARR differentiated by calendar periods, such as on-peak, off-peak, weekend, 7x24



Source: FGD Questionnaire Survey, Question 17.

Figure 79. Interest in monthly allocation of ARR Entitlements

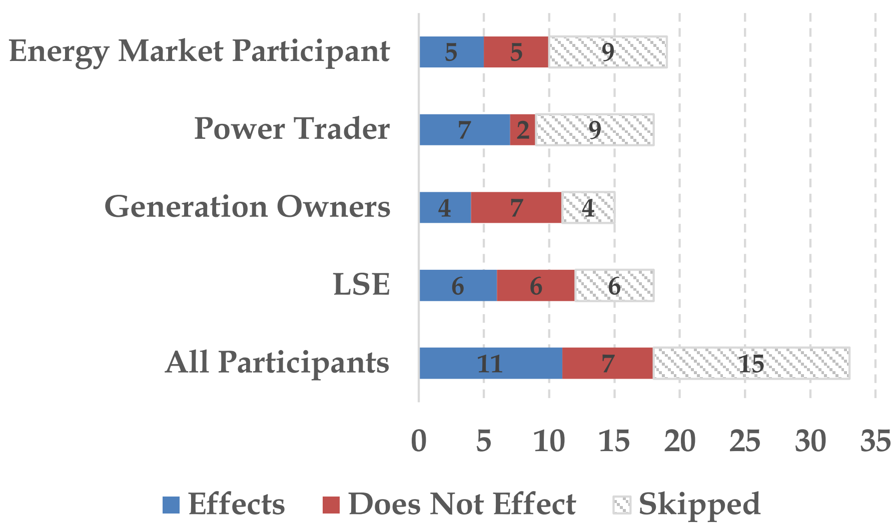


Source: FGD Questionnaire Survey, Question 16.

12.4.3 Effect of ARRs on consumption, production, and trading decisions

Eleven (61%) of the respondents stated that the availability of ARRs influences their business decisions in consuming, producing, and trading electricity; these respondents represented LSEs, generation owners, and traders, as seen below in Figure 80. Of the six LSEs who answered in this way, only five had identified themselves as power traders. Conversely, two of the seven power traders were not LSEs. LSEs and energy market participants' sentiments were divided evenly.

Figure 80. Effect of ARR allocations on stakeholder's business decisions



Source: FGD Questionnaire Survey, Question 20.

The stakeholders who viewed ARRs as influential for their business strategy, believed that the ARRs allocation process is integrally tied to the FTR auctions; therefore, any changes to the availability of ARRs would impact their trading decisions in the FTR auctions. Furthermore, they commented that the availability of ARRs helped them mitigate risk, essentially by reducing the need to purchase FTRs.

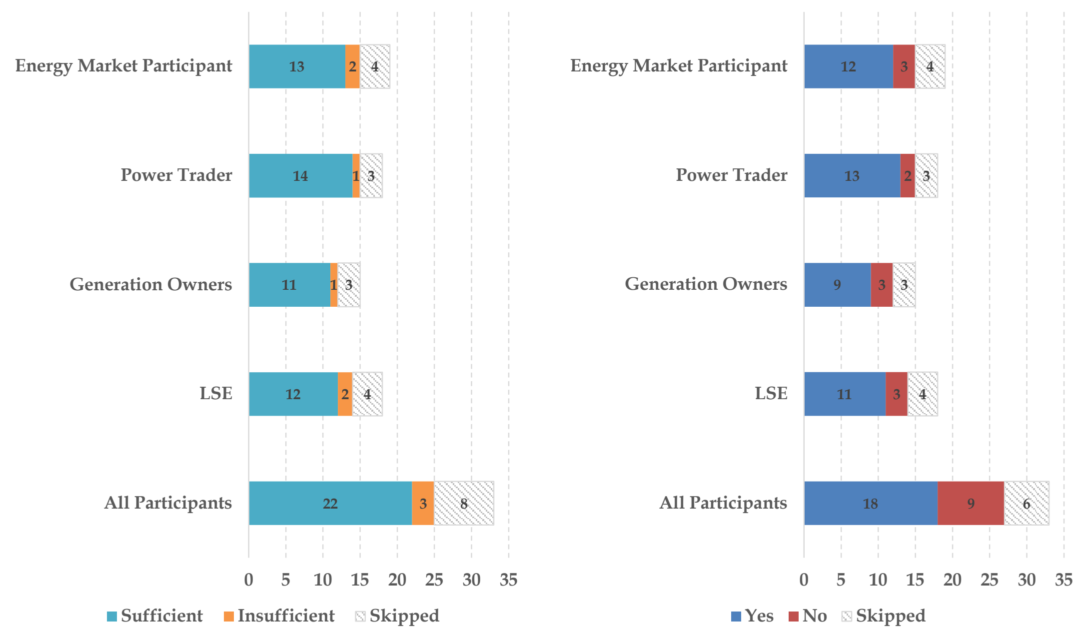
12.5 Insights into FTR products and auctions

The second part of the questionnaire focused on stakeholders' views on the FTR product and auctions. In contrast to the ARR allocation process, the number of respondents satisfied with the current FTR mechanism was greater: 67% of the respondents expressed satisfaction. Of those who self-identified as LSEs, 78.5% were satisfied. The respondents also echoed the sentiment observed in the FGDs, favoring an increase in FTR granularity. The survey responses indicated an interesting distinction between those identifying as load versus those identifying as generation owners with respect to the kind of impact FTRs had on their business decisions. There was also a division of opinion regarding Long-Term FTR auctions.

12.5.1 Sufficiency vs. Satisfaction

In contrast to ARRs, most stakeholders were satisfied with the FTR mechanism currently in place, and 88% of survey respondents indicated that current FTR auctions are sufficient, as shown in Figure 81. The survey respondents who approved of the current FTR auctions self-identified as LSEs, generation owners, power traders, end-use consumers. For example, 18 of the 27 entities (67%) responding to this question indicated that they were satisfied with the FTR auctions and felt that they met their needs.

Figure 81. Stakeholders' views on FTR auction, sufficiency vs. satisfaction



Source: FGD Questionnaire Survey, Question 42 and 43.

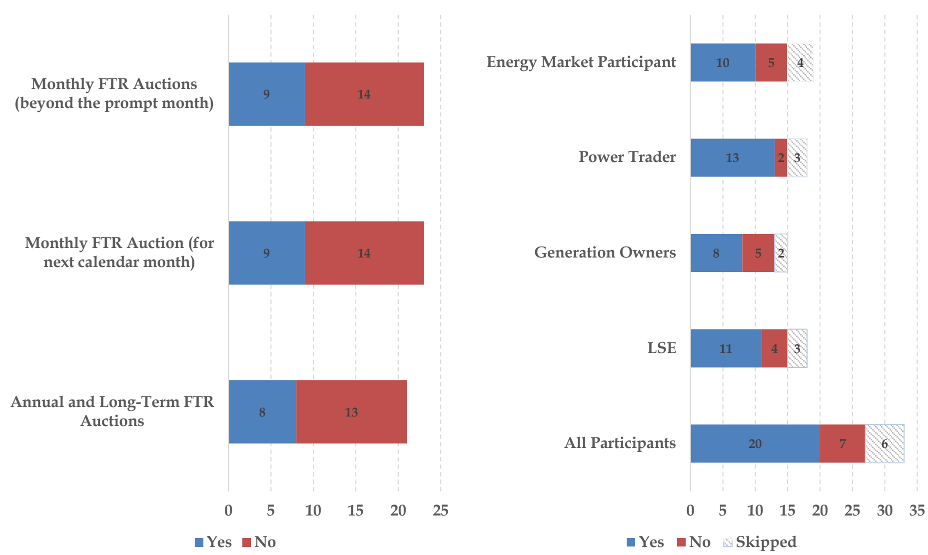
There were some differences in terms of the changes to the auctions. Some of the respondents stated that they felt the market would benefit from more FTR auctions, boosting their opportunity to hedge their load. However, other respondents also remarked that the current number of FTR auctions was adequate, and no additional auctions are needed. Other areas of FTR improvement mentioned in the survey include:

- provide greater granularity with FTR products; and
- create a stable market rule and update PJM's software technology to improve performance.

12.5.2 Views on granularity of FTR products

Throughout the FGDs sessions and in the responses to the survey questions, stakeholders expressed a keen interest in additional FTR granularity. As shown in Figure 82, approximately 75% of the respondents indicated their interest in greater FTR granularity, stating that it would help them achieve specific congestion profiles. Of the twenty-seven respondents, three were LSEs or end-use customers (and not generation owners or power traders). Two respondents noted that an increase in FTR granularity would better account for the impact of renewable energy on congestion during specific periods.[247] Additionally, three respondents also remarked that the increase of FTR granularity would improve liquidity and allow for more accurate price discovery. Those who were against more FTR granularity felt that consumers (load) would be forced take on additional risks due to the additional number of FTR products available (this concern was linked to increased possibility of underfunding).

Figure 82. Stakeholder views on biddable points and increase of FTR granularity



Source: FGD Questionnaire Survey, Questions 38, 39 40, and 41.

While most stakeholders supported more FTR granularity, there was less support for additional biddable points (new paths). Eight respondents (38%) preferred new paths. The main concern against adding new biddable points stemmed from the belief that such a change would increase the risk of FTR underfunding as there will be more source and sink points to account for. Many stakeholders, including financial participants such as power traders, also commented during the FGDs that they did not want to reduce the number of biddable points. In particular, two

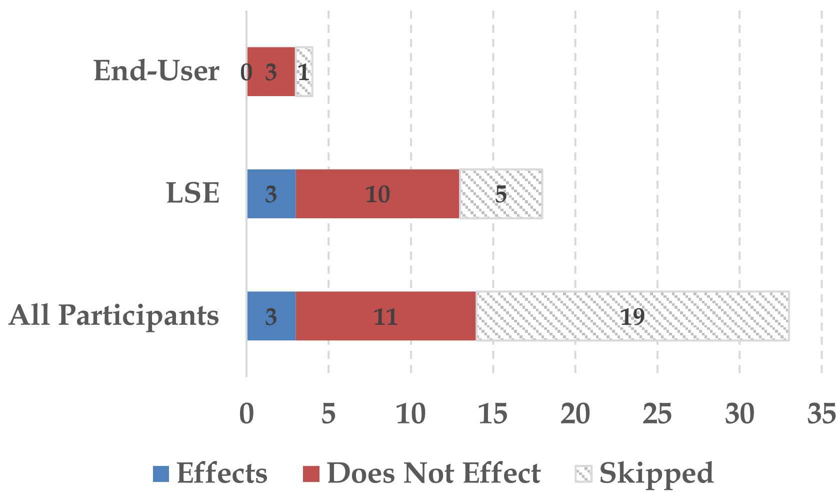
[247] FGD Questionnaire Survey, Question 39-41.

stakeholders stated that reduced biddable points might reduce liquidity in the market and negatively affect price discovery.[248]

12.5.3 Influence of FTRs on trading and other business decisions

As summarized in Figure 83, the availability of FTRs generally did not influence LSEs/end-use consumer's behavior in purchasing electricity. The figure shows that only three (21%) of the eleven respondents felt that FTRs influence their decision to buy or consume electricity. Likewise, the availability of FTRs did not influence the majority of respondents' decision to generate electricity. As shown in Figure 84 five (35%) of the respondents stated that FTRs affected their generation decision.

Figure 83. Effect of FTR products and auction on LSE and end-use consumer's electricity purchase decisions

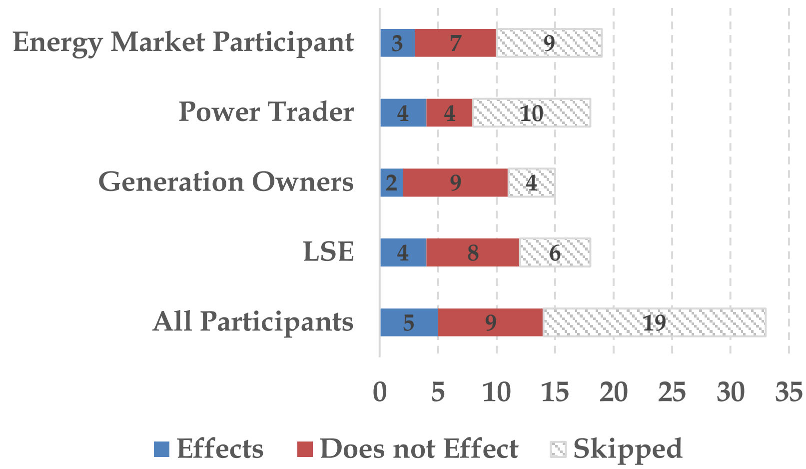


Source: FGD Questionnaire Survey, Question 35.

In contrast, seventeen (73%) of the respondents stated that FTRs affect their business decisions. This dichotomy lies in the distinction in the phrasing of the two questions and operational considerations. The spot market obligates LSEs, end-use consumers, and generators to either generate or consume electricity, regardless if the congestion cost was hedged or not. In other words, the existence of FTRs (and ARRs) does not change the efficient production and consumption decisions dictated by LMPs. However, to the extent that ARRs and FTRs support hedging and forward markets, we would expect that survey respondents would indicate that the presence of ARRs and FTRs does affect longer-term decisions.

[248] FGD FTR Group, September 15, 2020.

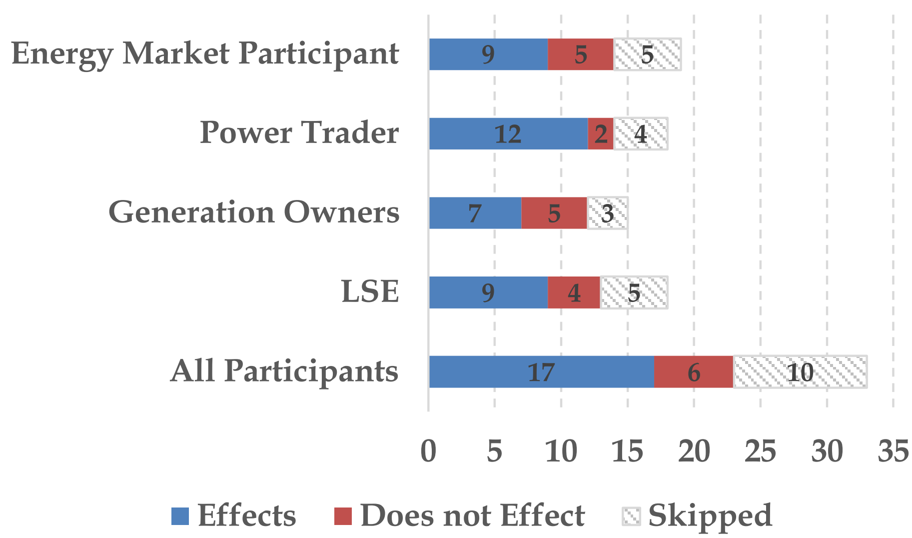
Figure 84. Effect of FTR products and auctions on stakeholders' (who own/develop/operate generation in PJM, or represent such an entity) decision electricity sale or production



Source: FGD Questionnaire Survey, Question 36.

LSEs and power traders were the entities that more frequently (in percentage terms) affirmed that FTRs did not affect their purchases and electricity sale decisions, as shown in Figure 83 and Figure 84, respectively.

Figure 85. Effect of the availability of FTR products and auctions on stakeholder's business decisions

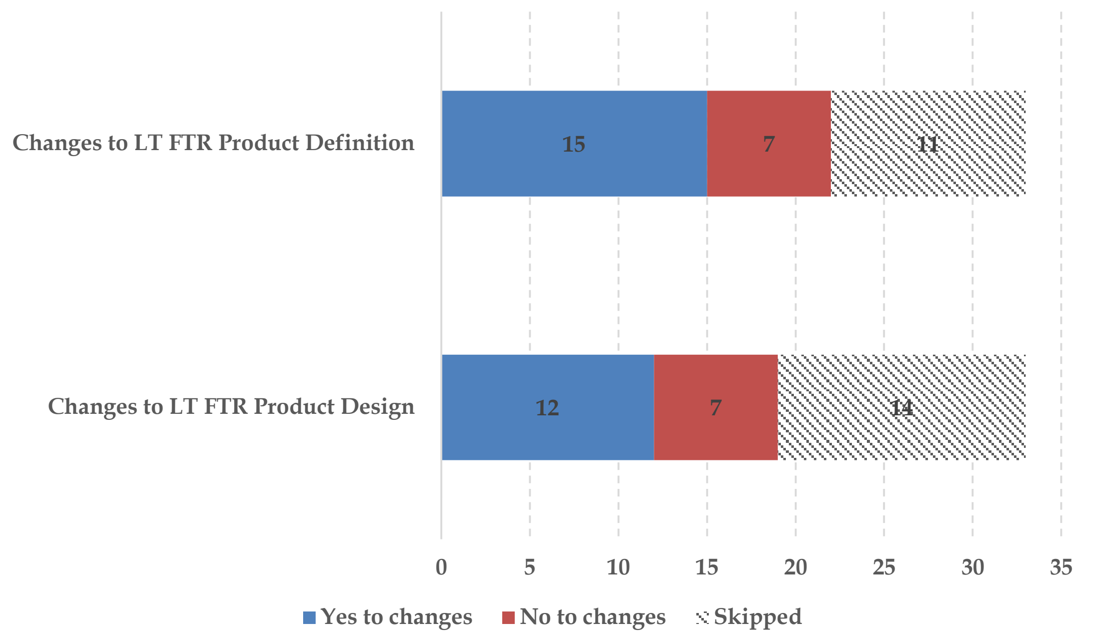


Source: FGD Questionnaire Survey, Question 37.

12.5.4 Views on long-term FTR product

The survey sought stakeholder feedback about the Long-Term FTR ("LT FTR") product. Two open-ended questions were asked: (1) how would you change the definition of LT FTR product, and (2) how would you change the design of the LT FTR auction. As illustrated in Figure 86, 63% of the respondents wanted to see a change in the auction design, and 68% preferred a change in the definition of the product. The "design" question refers to the structure of the LT FTR auction process. In contrast, the "definition" question refers to the details of the LT FTR product, such as its granularity, biddable points, and term length.

Figure 86. Many stakeholders expressed desire to change both the definition and design of LT FTR Auction.



Source: FGD Questionnaire Survey, Questions 46 and 47.

Among the respondents, one participant (identified as a generation owner, power marketer, and transmission utility) answered that they would like to see the LT FTR completely removed. The remaining respondents who sought to change the design and definition of the LT FTR auction asked for incremental changes.

While a slight majority of the stakeholders agreed that LT FTR products could be improved, the preferred path for accomplishing this was not unanimously supported. Only three stakeholders echoed each other's opinions, which included (i) introduction of LT FTR options and (ii) making LT FTR auctions monthly. Other proposals, each from different individual stakeholders, included:

- to add granular time-of-use LT FTR products, such as 7x8 (nighttime off-peak) or 2x16 (remaining (weekend daytime) off-peak hours);
- to allow bidding at generator nodes when a new entrant is building a project and scheduled to be in service;
- to allocate LT FTRs to LSEs and enable them to sell the products at auctions;
- to reduce LT FTR auctions to three rounds rather than its current five rounds; and
- to establish a price floor and reservation price for LT FTR products during auctions.

13 Appendix E: Additional details for analyses undertaken to support Task 3

This Appendix presents additional analysis supporting the discussion in Section 6 of this report. This includes details of statistical analysis on the predictive power of FTR auctions (Section 13.1), analysis on network capacity allocated during ARR allocation process (Section 13.2), details related to congestion charges returned to load, and impact of self-scheduling by transmission zone (Sections 13.3 to 13.6), details related to FTR pricing and profitability (Sections 13.7 and 13.8), and illustration on LEI's estimation on long-term benefits of non-load participation in FTR auctions (Section 13.9).

13.1 Statistical analyses of annual, monthly, and long-term FTR auctions

13.1.1 LEI's econometric methodology

Using regression techniques, LEI tested whether nodal prices from various FTR auctions had any predictive power over day-ahead CLMPs. Nodal prices from the auctions were used as independent (explanatory) variables, while day-ahead CLMPs were the dependent variable. The underlying data was cross-sectional in nature, representing individual nodes on the PJM system. Individual dummy variables were introduced to segment the data (a dummy variable of 1 was assigned to auction results with values of >=0) to address issues of autocorrelation and limited fixed effects. Nodes with auction prices with N/A were removed. To reduce the degree of potential heteroskedasticity[249] in the model, a robust standard error[250] technique was used. All work was performed using Stata.

13.1.2 Statistical inferences used to interpret the results of the tests

Based on the test results of running the panel regression in STATA, the following analysis was summarized for each auction type (annual auctions, monthly auctions, and long-term FTR auctions). LEI also ran a regression using simulated annual auction results to test the relative predictive power of the auctions if financial participants were removed.

F-Statistic (or "F-stat") documents the overall explanatory power of the model. In general, an F-Stat is a ratio of two quantities that are expected to be roughly equal under the null hypothesis (i.e., if the model explains none of the variations of the dependent variable, i.e., the auction clearing prices). Therefore, a larger F-Stat value confirms the regression model's overall

[249] Heteroskedasticity, or non-constant variance, refers to the dispersion of the residual in an econometric model. Data with large values may generate more widely-dispersed residuals. This can result in less statistical confidence in the resulting elasticity estimates. Heteroskedasticity can be tested for and corrected in an econometric model.

[250] Robust standard errors standard errors are a technique to obtain unbiased standard errors of OLS coefficients under heteroscedasticity. the presence of heteroscedasticity violates the Gauss Markov assumptions that are necessary to render OLS the best linear unbiased estimator Best Linear Unbiased Estimator.

significance and indicates strong fit and the predictive ability of the independent variable (in our case, auction prices) in explaining the dependent variable (in our case, CLMPs). The higher the F-stat, the better.

The **t-statistic or "T-value"** tests the hypothesis of statistical significance for the estimated coefficient on an independent variable, namely if the coefficient is different from 0 in a statistically significant way. In order to reject the null hypothesis, we need to see a t-value greater than the critical value of 1.96 (for 95% confidence levels). T-values show the importance of a variable in a regression model.

R-squared is the coefficient of correlation and it measures the dispersion of the data around the line-of-best fit. The R-squared value for any line-of-best-fit will range from 1 (if all the data points are exactly on the line-of-best-fit, i.e., a perfect correlation) to as low as 0 (if the data are so dispersed, or noisy, such that linear relationship is not a good fit). An R-squared of 0 implies that there is no correlation that can be explained by the line-of-best-fit. In this study, the R-squared shows the amount of variance in the CLMPs for each node (y variable) is explained by respective auction clearing prices (x variable). Goodness-of-fit measure for linear regression models are reported on a scale of 0 to 1; the higher R-squared, the better.

13.1.3 Statistical analysis of annual FTR auctions

LEI ran a multi-variate cross-sectional regression model based on the annual auction clearing price and respective annualized CLMPs for the 6,014 PJM nodes across three planning years ("PY") and three FTR product periods (24 H, on-peak and off-peak). The summary of the results is as follows:

1. F-Stat results are significant across auctions. This confirms the auction result's ability to predict actual congestions, and therefore the CLMPs more efficiently.

Planning Year (PY)	F-Stat		
	24H	On-peak	Off-peak
PY2017-18	2855.18	2536.56	2399.94
PY2018-19	4202.32	2153.99	14595.2
PY2019-20	4989.19	2408.63	9566.56

2. T-Statistics across the tests confirm that most of the indedent variables possess estimated coefficients are statistically significant. This confirms that the annual auction results explain or predict the dsitribution of realized CLMPs CLMPs.

3. R-squared is consistently high across the PYs and the various FTR products in the annual auctions. Though, as a principle, an R-squared may capture the noise in the cross-sectional data, it also indicates goodness of linear fit, in the relationship between auction prices and CLMPs. Off-peak FTR product has higher R-squared values because there is less likely to be less

Planning Year (PY)	R-Squared		
	24H	On-peak	Off-peak
PY2017-18	0.6767	0.5853	0.7267
PY2018-19	0.7138	0.6467	0.8333
PY2019-20	0.6543	0.5242	0.7475

(unexplained) variability in congestion during off-peak periods.

The results of the regression models show that annual auctions have statistically significant predictive power for actual CLMPs. This indicates the overall efficiency of the FTR auctions, the effectiveness of the FTR auctions to set the value of ARRs held by load, and the reasonableness of price discovery that market participants attain o studying annual FTR auction outcomes.

13.1.3.1 Summary of the econometric results of the Annual Auctions in PJM across TOUs (on-peak, off-peak, and 24h). Periods covered PY2017-18, PY2018-19, and PY2019-20

On-Peak

```
19 . regress CLMP1718_OnP AA1718_OnP 1AA1718_OnP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    2536.56
                                                Prob > F          =     0.0000
                                                R-squared         =     0.5853
                                                Root MSE          =     1.9427

------------------------------------------------------------------------------
             |               Robust
CLMP1718_OnP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1718_OnP |   1.911542    .107666    17.75   0.000     1.700479    2.122606
 1AA1718_OnP |   1.771758    .100788    17.58   0.000     1.574178    1.969339
       _cons |  -2.115892   .0477633   -44.30   0.000    -2.209525   -2.022259
------------------------------------------------------------------------------
```

```
27 . regress CLMP1819_OnP AA1819_OnP 1AA1819_OnP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    2153.99
                                                Prob > F          =     0.0000
                                                R-squared         =     0.6467
                                                Root MSE          =     1.5991

------------------------------------------------------------------------------
             |               Robust
CLMP1819_OnP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1819_OnP |   2.154539   .0705653    30.53   0.000     2.016206    2.292872
 1AA1819_OnP |  -.4847759   .1122313    -4.32   0.000    -.7047896   -.2647622
       _cons |  -1.551569   .0478448   -32.43   0.000    -1.645362   -1.457776
------------------------------------------------------------------------------
```

```
35 . regress CLMP1920_OnP AA1920_OnP 1AA1920_OnP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    2408.63
                                                Prob > F          =     0.0000
                                                R-squared         =     0.5242
                                                Root MSE          =     1.2381

------------------------------------------------------------------------------
             |               Robust
CLMP1920_OnP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1920_OnP |   1.261779   .0285407    44.21   0.000     1.205829    1.317729
 1AA1920_OnP |  -.2116692   .0818693    -2.59   0.010    -.3721623    -.051176
       _cons |   -1.07141    .051061   -20.98   0.000    -1.171508   -.9713123
------------------------------------------------------------------------------
```

Off-Peak

```
43 . regress CLMP1718_OffP AA1718_OffP 1AA1718_OffP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    2399.94
                                                Prob > F          =     0.0000
                                                R-squared         =     0.7267
                                                Root MSE          =     1.5798

------------------------------------------------------------------------------
             |               Robust
CLMP1718_~fP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 AA1718_OffP |   2.867568   .1285538    22.31   0.000     2.615556    3.119579
1AA1718_OffP |   1.553983   .1287194    12.07   0.000     1.301646    1.806319
       _cons |  -2.382768   .0821707   -29.00   0.000    -2.543852   -2.221684
------------------------------------------------------------------------------
```

```
51 . regress CLMP1819_OffP AA1819_OffP 1AA1819_OffP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =   14595.20
                                                Prob > F          =     0.0000
                                                R-squared         =     0.8333
                                                Root MSE          =     .51515

------------------------------------------------------------------------------
             |               Robust
CLMP1819_~fP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 AA1819_OffP |   1.026612   .0208833    49.16   0.000     .9856728     1.06755
1AA1819_OffP |   .2372918   .0398687     5.95   0.000     .1591349    .3154488
       _cons |  -.9903253   .0187134   -52.92   0.000     -1.02701   -.9536403
------------------------------------------------------------------------------
```

```
59 . regress CLMP1920_OffP AA1920_OffP 1AA1920_OffP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    9566.56
                                                Prob > F          =     0.0000
                                                R-squared         =     0.7475
                                                Root MSE          =     .61889

------------------------------------------------------------------------------
             |               Robust
CLMP1920_~fP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 AA1920_OffP |   .8710825   .0191774    45.42   0.000     .8334879    .9086772
1AA1920_OffP |   .5558362   .0457336    12.15   0.000      .466182    .6454904
       _cons |    -1.0722   .0251677   -42.60   0.000    -1.121538   -1.022863
------------------------------------------------------------------------------
```

24h

```
67 . regress CLMP1718_24H AA1718_24H 1AA1718_24H, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    2855.18
                                                Prob > F          =     0.0000
                                                R-squared         =     0.6767
                                                Root MSE          =     1.6688

------------------------------------------------------------------------------
             |               Robust
CLMP1718_24H |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1718_24H |   1.156888   .0585769    19.75   0.000     1.042056    1.271719
 1AA1718_24H |   1.802737   .1079487    16.70   0.000     1.591119    2.014355
       _cons |  -2.387367   .0602859   -39.60   0.000    -2.505549   -2.269185
------------------------------------------------------------------------------
```

```
75 . regress CLMP1819_24H AA1819_24H 1AA1819_24H, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    4202.32
                                                Prob > F          =     0.0000
                                                R-squared         =     0.7138
                                                Root MSE          =     1.0043

------------------------------------------------------------------------------
             |               Robust
CLMP1819_24H |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1819_24H |   .7752738   .0238921    32.45   0.000     .7284367    .8221108
 1AA1819_24H |  -.1203669    .081725    -1.47   0.141    -.2805772    .0398433
       _cons |  -1.197692   .0348765   -34.34   0.000    -1.266062   -1.129321
------------------------------------------------------------------------------
```

```
83 . regress CLMP1920_24H AA1920_24H 1AA1920_24H, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    4989.19
                                                Prob > F          =     0.0000
                                                R-squared         =     0.6543
                                                Root MSE          =     .81729

------------------------------------------------------------------------------
             |               Robust
CLMP1920_24H |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1920_24H |   .4888726   .0125244    39.03   0.000     .4643204    .5134248
 1AA1920_24H |   .7657701   .0531168    14.42   0.000      .661642    .8698982
       _cons |  -1.237001   .0297326   -41.60   0.000    -1.295288   -1.178714
------------------------------------------------------------------------------
```

13.1.4 Statistical analysis of simulated FTR auctions

PJM created a hypothetical case where it removed the offers of financial market players from FTR auctions in 2018/19 PY and simulated the auction outcomes. LEI ran a multi-variate cross-sectional regression model based on the simulated annual auction clearing price and respective annualized CLMPs for the 6,774 PJM nodes in the 2018/19 PY and three FTR product periods (24 H, on-peak and off-peak). LEI then compared the statistical inferences based on the simulated auction results against those using actual auction results (see Section 6.7). The summary of the comparative results is as follows:

1. F-Stat results are significant across both annual auctions and the simulated auctions. However, the F-Stat is higher in the regression model based on annual auctions, indirectly confirming that annual auctions are more efficient with financial participants and that the presence of financial participants further improves the predictive power of the annual auctions.

	F-Stat	
PY2018-19	Annual	Simulated
24H	4,202.3	3,277.4
On-peak	2,154.0	2,197.2
Off-peak	14,595.2	7,220.4

2. T-Statistics confirms that independent variables are statistically significant. However, as with the F-State, the T-Stats are higher when we used actual auction prices as compared to simulated auction prices.
3. R-squared is also higher in the models that used actual auction results as compared to simulated auction results. If we accept that the simulated auction results captured the unbiased impact of financial participants on auction dynamics, the comparative values of R-Squared indicates that presence of financial participants improves the linear fit of the regression model that explains the predictive power of auction results on CLMPs.[251]

	R-Squared	
PY2018-19	Annual	Simulated
24H	0.7138	0.5342
On-peak	0.6467	0.489
Off-peak	0.8333	0.6682

The results of the regression models show that annual auctions with financial participants are more efficient (given the higher explanatory power) and can better explain/predict CLMPs.

[251] It is important to remember that the R-squared captures noise in data and a low R-squared may reflect on omitted variable problem (possibly a factor that affected the simulation, which we could not control for in our regression analysis and comparison).

13.1.4.1 Summary of the econometric results of the simulated auction results and annual auction results (period covered PY2018-19)

Simulated Annual Auctions — On-Peak

```
27 . regress CLMP_201819_OnPeak Ann_Sim_NonF_OnPeak 1Ann_Sim_NonF_OnPeak, robust

Linear regression                               Number of obs     =      6,774
                                                F(2, 6771)        =    2197.21
                                                Prob > F          =     0.0000
                                                R-squared         =     0.4890
                                                Root MSE          =     1.8978

------------------------------------------------------------------------------------------
                     |               Robust
  CLMP_201819_OnPeak |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
---------------------+--------------------------------------------------------------------
 Ann_Sim_NonF_OnPeak |   2.045535    .1032885    19.80   0.000     1.843058    2.248013
1Ann_Sim_NonF_OnPeak |   .1189225    .1454565     0.82   0.414     -.166218     .404063
               _cons |  -1.541306    .0536713   -28.72   0.000    -1.646518   -1.436093
------------------------------------------------------------------------------------------
```

Simulated Annual Auctions — Off-Peak

```
34 . regress CLMP_201819_OffPeak Ann_Sim_NonF_OffPeak 1Ann_Sim_NonF_OffPeak, robust

Linear regression                               Number of obs     =      6,774
                                                F(2, 6771)        =    7220.35
                                                Prob > F          =     0.0000
                                                R-squared         =     0.6682
                                                Root MSE          =     .71291

-------------------------------------------------------------------------------------------
                      |               Robust
  CLMP_201819_OffPeak |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
----------------------+--------------------------------------------------------------------
 Ann_Sim_NonF_OffPeak |   .9298876    .0293812    31.65   0.000     .8722913    .9874839
1Ann_Sim_NonF_OffPeak |   .4733172    .0505356     9.37   0.000     .3742515     .572383
                _cons |  -.7901499    .0300301   -26.31   0.000    -.8490183   -.7312815
-------------------------------------------------------------------------------------------
```

Simulated Annual Auctions — 24h

```
19 . regress CLMP_201819_24H Ann_Sim_NonF_24H 1Ann_Sim_NonF_24H, robust

Linear regression                               Number of obs     =      6,774
                                                F(2, 6771)        =    3277.38
                                                Prob > F          =     0.0000
                                                R-squared         =     0.5342
                                                Root MSE          =     1.2614

---------------------------------------------------------------------------------------
                  |               Robust
  CLMP_201819_24H |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
------------------+--------------------------------------------------------------------
 Ann_Sim_NonF_24H |   .7024734     .032711    21.48   0.000     .6383496    .7665971
1Ann_Sim_NonF_24H |   .3034941    .1006111     3.02   0.003     .1062647    .5007235
            _cons |  -1.040367     .048228   -21.57   0.000    -1.134909   -.9458253
---------------------------------------------------------------------------------------
```

Annual Auctions (actual) — On-Peak

```
27 . regress CLMP1819_OnP AA1819_OnP 1AA1819_OnP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    2153.99
                                                Prob > F          =     0.0000
                                                R-squared         =     0.6467
                                                Root MSE          =     1.5991

------------------------------------------------------------------------------
             |               Robust
CLMP1819_OnP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1819_OnP |   2.154539    .0705653    30.53   0.000     2.016206    2.292872
 1AA1819_OnP |  -.4847759    .1122313    -4.32   0.000    -.7047896   -.2647622
       _cons |  -1.551569    .0478448   -32.43   0.000    -1.645362   -1.457776
------------------------------------------------------------------------------
```

Annual Auctions (actual) — Off-Peak

```
51 . regress CLMP1819_OffP AA1819_OffP 1AA1819_OffP, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =   14595.20
                                                Prob > F          =     0.0000
                                                R-squared         =     0.8333
                                                Root MSE          =     .51515

------------------------------------------------------------------------------
             |               Robust
CLMP1819_~fP |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 AA1819_OffP |   1.026612    .0208833    49.16   0.000     .9856728     1.06755
1AA1819_OffP |   .2372918    .0398687     5.95   0.000     .1591349    .3154488
       _cons |  -.9903253    .0187134   -52.92   0.000     -1.02701   -.9536403
------------------------------------------------------------------------------
```

Annual Auctions (actual) — 24h

```
75 . regress CLMP1819_24H AA1819_24H 1AA1819_24H, robust

Linear regression                               Number of obs     =      6,014
                                                F(2, 6011)        =    4202.32
                                                Prob > F          =     0.0000
                                                R-squared         =     0.7138
                                                Root MSE          =     1.0043

------------------------------------------------------------------------------
             |               Robust
CLMP1819_24H |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
  AA1819_24H |   .7752738    .0238921    32.45   0.000     .7284367    .8221108
 1AA1819_24H |  -.1203669     .081725    -1.47   0.141    -.2805772    .0398433
       _cons |  -1.197692    .0348765   -34.34   0.000    -1.266062   -1.129321
------------------------------------------------------------------------------
```

13.1.5 Statistical analyses of monthly FTR auctions

The monthly FTR auctions at PJM aim to provide residual FTRs available every month. These auctions give market participants, including the load, additional opportunities to hedge congestion with an FTR product that is more granular (for a specific month) than an annual product. To ascertain if the monthly auctions provide price discovery, LEI ran a multi-variate cross-sectional regression model based on the simulated monthly auction clearing prices and respective annualized CLMPs. LEI focused on the results from monthly auctions for the 2018-19 planning period and the 24-hour FTR obligation. The monthly auction clearing nodal prices and certain dummy variables (to identify the timeframe of the auction relative to settlement) were introduced as independent variables for each node, while the monthly CLMP was the dependent variable. The monthly CLMP prices were matched with the respective auction periods. For example the September 2018 CLMP was used to guage the efficiency of monthly auctions for September 2018 products. And in that model, LEI included September clearing nodal price reported in the August 2018 auction (i.e., the prompt month), and in the July 2018 auction (i.e., the month before the prompt month). Each month was tested individually. The number of nodes or observations varied by month.

The summary of the results is as follows:

1. F-Stat results are significant across most monthly models. This confirms the auction result's ability to predict actual congestions, and therefore the CLMPs more efficiently. With the exception of a few months (such as Dec-18 and Feb-19), which may have experienced some "difficult to predict" weather-driven congestion, we observe a high F-Stat for the monthly auctions.

Months of PY 2018-19	F-Stat 24H	Observations (nodes)
Jun-18	10,257.6	6,823
Jul-18	5,020.1	6,776
Aug-18	1,000.6	6,753
Sep-18	2,211.8	6,654
Oct-18	1,240.3	6,538
Nov-18	2,500.9	6,494
Dec-18	191.5	6,536
Jan-19	2,741.0	6,546
Feb-19	983.6	6,564
Mar-19	3,563.5	6,539
Apr-19	3,467.4	6,489
May-19	6,212.0	6,474

2. T-Statistics confirm that most of the independent variables have estiamted coefficeints that are statistically significant. This demonstrates that most of the monthly auction outcomes can contribute positively to predicting the pattern congestion.

3. With the exception of a few months (such as Aug-18, Dec-18, and Feb-19), in which other factors may have driven congestion (CLMPs), we observe reasonably high R-squared values for the monthly values.

Months of PY 2018-19	R-Squared 24H	Observations (nodes)
Jun-18	0.6984	6,823
Jul-18	0.7662	6,776
Aug-18	0.3525	6,753
Sep-18	0.8453	6,654
Oct-18	0.7852	6,538
Nov-18	0.9087	6,494
Dec-18	0.3156	6,536
Jan-19	0.6452	6,546
Feb-19	0.2785	6,564
Mar-19	0.8188	6,539
Apr-19	0.786	6,489
May-19	0.8592	6,474

To conclude, econometric analysis of monthly auctions suggests that monthly auctions prices are efficient and provide valuable information to the market about realized congestion in the day-ahead energy market, supporting price discovery.

13.1.5.1 Summary of the econometric results of the Monthly Auctions in PJM (24h FTR Obligations), PY2018-19

June 2018 to September 2018 *(top-down)*

15 . regress CLMP_June18 lJuneCurrent JuneCurrent, robust

Linear regression

Number of obs	=	6,823
F(2, 6820)	=	10257.61
Prob > F	=	0.0000
R-squared	=	0.6984
Root MSE	=	1.6345

CLMP_June18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
lJuneCurrent	.6711664	.0672342	9.98	0.000	.5393664	.8029664
JuneCurrent	1.018998	.0152034	67.02	0.000	.9891944	1.048801
_cons	-4.222477	.032059	-131.71	0.000	-4.285323	-4.159631

20 . regress CLMP_July18 JulyCurrent lJulyCurrent JulyPrompt lJulyPrompt, robust

Linear regression

Number of obs	=	6,776
F(4, 6771)	=	5020.05
Prob > F	=	0.0000
R-squared	=	0.7662
Root MSE	=	.86313

CLMP_July18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
JulyCurrent	1.173932	.0380953	30.82	0.000	1.099253	1.248611
lJulyCurrent	-.6480027	.0389688	-16.63	0.000	-.7243938	-.5716115
JulyPrompt	-.5541539	.0461794	-12.00	0.000	-.6446801	-.4636278
lJulyPrompt	.0095696	.0424512	0.23	0.822	-.0736482	.0927873
_cons	-1.701211	.0240132	-70.84	0.000	-1.748284	-1.654137

27 . regress CLMP_Aug18 AugCurrent lAugCurrent AugPrompt lAugPrompt AugPrompt2 lAugPr

Linear regression

Number of obs	=	6,753
F(6, 6746)	=	1000.55
Prob > F	=	0.0000
R-squared	=	0.3525
Root MSE	=	1.3838

CLMP_Aug18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
AugCurrent	.6953207	.0463122	15.01	0.000	.6045341	.7861072
lAugCurrent	-.1421966	.0912277	-1.56	0.119	-.3210318	.0366385
AugPrompt	-.5784603	.0768442	-7.53	0.000	-.7290992	-.4278214
lAugPrompt	1.338125	.0785999	17.02	0.000	1.184044	1.492206
AugPrompt2	.4158467	.0711321	5.85	0.000	.2764053	.5552881
lAugPrompt2	-.6294846	.0842204	-7.47	0.000	-.7945832	-.4643861
_cons	-1.382842	.0364353	-37.95	0.000	-1.454267	-1.311418

October 2018 to January 2019 *(top-down)*

43 . regress CLMP_Oct18 OctCurrent lOctCurrent OctPrompt lOctPrompt OctPrompt2 lOct

Linear regression

Number of obs	=	6,538
F(6, 6531)	=	1240.31
Prob > F	=	0.0000
R-squared	=	0.7852
Root MSE	=	2.4627

CLMP_Oct18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
OctCurrent	.295619	.5869758	0.50	0.615	-.8550456	1.446284
lOctCurrent	-2.689373	.4342235	-6.19	0.000	-3.540593	-1.838153
OctPrompt	3.691597	.4697409	7.86	0.000	2.770752	4.612443
lOctPrompt	-.1106288	.2886806	-0.38	0.702	-.6765373	.4552796
OctPrompt2	-2.25274	.394128	-5.72	0.000	-3.02536	-1.48012
lOctPrompt2	-.4260878	.2352146	-1.81	0.070	-.8871853	.0350097
_cons	-2.013113	.0954695	-21.09	0.000	-2.200265	-1.825962

51 . regress CLMP_Nov18 NovCurrent lNovCurrent NovPrompt lNovPrompt NovPrompt2 lNo

Linear regression

Number of obs	=	6,494
F(6, 6487)	=	2500.85
Prob > F	=	0.0000
R-squared	=	0.9087
Root MSE	=	1.5554

CLMP_Nov18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
NovCurrent	3.235636	.1143537	28.29	0.000	3.011465	3.459807
lNovCurrent	-.720932	.1839685	-3.92	0.000	-1.081571	-.360293
NovPrompt	.2338631	.1891205	1.24	0.216	-.1368755	.6046017
lNovPrompt	-.7265941	.1438994	-5.05	0.000	-1.008684	-.4445039
NovPrompt2	-2.399669	.1660193	-14.45	0.000	-2.725121	-2.074216
lNovPrompt2	1.834595	.1976936	9.28	0.000	1.44705	2.22214
_cons	-3.0912	.1078582	-28.66	0.000	-3.302638	-2.879763

59 . regress CLMP_Dec18 DecCurrent lDecCurrent DecPrompt lDecPrompt DecPrompt2 lDe

Linear regression

Number of obs	=	6,536
F(6, 6529)	=	191.52
Prob > F	=	0.0000
R-squared	=	0.3156
Root MSE	=	2.0567

CLMP_Dec18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
DecCurrent	.4891027	.0490447	9.97	0.000	.3929591	.5852463
lDecCurrent	-.9584919	.078073	-12.28	0.000	-1.111541	-.8054433
DecPrompt	.9262654	.1498573	6.18	0.000	.6324959	1.220035
lDecPrompt	-.4160683	.1290459	-3.22	0.001	-.6690405	-.1630961
DecPrompt2	-.7928803	.1251362	-6.34	0.000	-1.038188	-.5475723
lDecPrompt2	.0015002	.1356055	0.01	0.991	-.2643309	.2673313
_cons	1.479627	.1098906	13.46	0.000	1.264205	1.695048

February 2019 to May 2019 *(top-down)*

75 . regress CLMP_Feb19 FebCurrent lFebCurrent FebPrompt lFebPrompt FebPrompt2 lFebP

Linear regression

Number of obs	=	6,564
F(6, 6557)	=	983.62
Prob > F	=	0.0000
R-squared	=	0.2785
Root MSE	=	.87706

CLMP_Feb19	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
FebCurrent	.1635757	.0165005	9.91	0.000	.1312293	.1959221
lFebCurrent	-.7041447	.0435028	-16.19	0.000	-.7894243	-.6188651
FebPrompt	.2840246	.0393586	7.22	0.000	.206869	.3611802
lFebPrompt	-.4245897	.0754662	-5.63	0.000	-.572528	-.2766513
FebPrompt2	-.3337147	.0285547	-11.69	0.000	-.3896912	-.2777381
lFebPrompt2	1.748103	.0572864	30.52	0.000	1.635803	1.860403
_cons	-.3148106	.0417677	-7.54	0.000	-.396689	-.2329323

83 . regress CLMP_March19 MarCurrent lMarCurrent MarPrompt lMarPrompt MarPrompt2 lMa

Linear regression

Number of obs	=	6,539
F(6, 6532)	=	3563.49
Prob > F	=	0.0000
R-squared	=	0.8188
Root MSE	=	.53995

CLMP_March19	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
MarCurrent	.8205309	.0255646	32.10	0.000	.7704159	.8706458
lMarCurrent	.2822734	.0314421	8.98	0.000	.2206367	.3439102
MarPrompt	-.0809706	.033493	-2.42	0.016	-.1466279	-.0153134
lMarPrompt	-.2114266	.041788	-5.06	0.000	-.2933448	-.1295085
MarPrompt2	-.1735431	.0483845	-3.59	0.000	-.2683927	-.0786936
lMarPrompt2	.1417341	.0577209	2.46	0.014	.0285823	.2548858
_cons	-1.711245	.0522672	-32.74	0.000	-1.813706	-1.608785

91 . regress CLMP_April19 AprCurrent lAprCurrent AprPrompt lAprPrompt AprPrompt2 1A

Linear regression

Number of obs	=	6,489
F(6, 6482)	=	3467.38
Prob > F	=	0.0000
R-squared	=	0.7860
Root MSE	=	.4428

CLMP_April19	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
AprCurrent	.6290578	.0285913	22.00	0.000	.5730095	.6851062
lAprCurrent	.2417186	.0240339	10.06	0.000	.1946043	.2888329
AprPrompt	.2584312	.0375775	6.88	0.000	.184767	.3320954
lAprPrompt	-.2239024	.055494	-4.03	0.000	-.3326889	-.1151159
AprPrompt2	-.4264614	.0190894	-22.34	0.000	-.463883	-.3890399
lAprPrompt2	.066886	.0555192	1.20	0.228	-.0419501	.175722
_cons	-1.157454	.0179384	-64.52	0.000	-1.192619	-1.122289

June 2018 to September 2018 *(top-down)*

```
35 . regress CLMP_Sept18 SeptCurrent lSeptCurrent SeptPrompt lSeptPrompt SeptPrompt

Linear regression                               Number of obs     =      6,654
                                                F(6, 6647)        =    2211.83
                                                Prob > F          =     0.0000
                                                R-squared         =     0.8453
                                                Root MSE          =     1.3175
```

CLMP_Sept18	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
SeptCurrent	1.134087	.0833202	13.61	0.000	.9707521	1.297421
lSeptCurrent	-1.520938	.0857087	-17.75	0.000	-1.688955	-1.352922
SeptPrompt	-.7428177	.1493983	-4.97	0.000	-1.035686	-.449949
lSeptPrompt	.9607348	.1060493	9.06	0.000	.7528441	1.168625
SeptPrompt2	.6139946	.1036443	5.92	0.000	.4108185	.8171708
lSeptPrompt2	1.111345	.1718009	6.47	0.000	.7745599	1.44813
_cons	-4.499788	.0816588	-55.10	0.000	-4.659866	-4.339711

October 2018 to January 2019 *(top-down)*

```
67 . regress CLMP_Jan19 JanCurrent lJanCurrent JanPrompt lJanPrompt JanPrompt2 lJanPro

Linear regression                               Number of obs     =      6,546
                                                F(6, 6539)        =    2740.96
                                                Prob > F          =     0.0000
                                                R-squared         =     0.6452
                                                Root MSE          =       1.57
```

CLMP_Jan19	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
JanCurrent	.9285561	.044167	21.02	0.000	.8419743	1.015138
lJanCurrent	.0006824	.0780575	0.01	0.993	-.1523359	.1537007
JanPrompt	.2579236	.0726701	3.55	0.000	.1154665	.4003806
lJanPrompt	.9182655	.4598129	2.00	0.046	.016882	1.819649
JanPrompt2	-.8973585	.0930789	-9.64	0.000	-1.079823	-.7148935
lJanPrompt2	.3751879	.4711111	0.80	0.426	-.5483439	1.29872
_cons	1.118083	.0545729	20.49	0.000	1.011102	1.225064

February 2019 to May 2019 *(top-down)*

```
99 . regress CLMP_May19 MayCurrent lMayCurrent MayPrompt lMayPrompt MayPrompt2 lMay

Linear regression                               Number of obs     =      6,474
                                                F(6, 6467)        =    6212.00
                                                Prob > F          =     0.0000
                                                R-squared         =     0.8592
                                                Root MSE          =     .72581
```

CLMP_May19	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
MayCurrent	.609643	.0631475	9.65	0.000	.485853	.733433
lMayCurrent	.7227792	.0804733	8.98	0.000	.5650249	.8805335
MayPrompt	.6280623	.1366053	4.60	0.000	.3602707	.895854
lMayPrompt	-.0527101	.0681565	-0.77	0.439	-.1863193	.0808991
MayPrompt2	-.2413441	.1142566	-2.11	0.035	-.4653248	-.0173634
lMayPrompt2	-.3585551	.0553029	-6.48	0.000	-.466967	-.2501432
_cons	-2.87418	.0260798	-110.21	0.000	-2.925305	-2.823055

13.1.6 Statistical analyses of long-term auctions

The Long-term FTR auctions at PJM aim to provide market participants with the ability to acquire a 3-year forward contract, with auctions held each year in June, September, and December prior to the start of the 2020-21 PY. To ascertain if the long-term FTR auctions can contribute to price discovery, LEI undertook n a multi-variate cross-sectional regression model based on the LT FTR auctions that produced FTR obligations (24 hour) for delivery in PY 2018-19. For each of the 5,694 nodes (CLMP) that could be matched against auction clearing prices in 2018-19, results from nine auctions were analyzed as independent (explanatory) variables. The LFT FTR auction clearing prices included results from 2016-2019 auction (round-1 year-3, round-2 year-3, round-3 year-3), 2017-2020 auction (round-1 year-2, round-2 year-2, round-3 year-2), and 2018-21 auction (round-1 year-1, round-2 year-1, round-3 year-1). LEI also introduced dummy variables that identified the number of months between the auction and start of delivery.

The summary of the results is as follows:

1. The F-Stat result is significant (F-value of 2,162.5), confirms the LT auction results' predictive power over actual congestion in the day-ahead energy market.
2. Most of the indepdent variables have stastically sinficiant T-values at the 95% confidene level. This demonstrates that most of the LT FTR auction results (and the dummy variables reflect the duration of time before delivery) contributed to predicting the pattern congestion.
3. The R-squared result is high (R-squared of 0.8667). Though the high R-squared confirms the goodness of the fit, i.e., the differences between the observed values (i.e., the auction prices) and model's predicted values (i.e., the CLMPs) are small and unbiased, yet given that the long-term auctions are at most 3-years ahead, the R-squared may contain much noise associated with congestion.

The test results indicate that long-term FTR auctions have some predictive power over CLMPs and therefore positively impact the price discovery process.

13.1.6.1 Summary of the econometric results of the long-term FTR auctions in PJM (24h) for PY2018-19

```
51 . regress HCLMP_201819 HPY1619Y3R1 ThirtySix_months HPY1619Y3R2 ThirtyThree_months HP
   > nths HPY1720Y2R2 TwentyOne_months HPY1720Y2R3 Eighteen_months HPY1821Y1R1 Twelve_mo
   > hs, robust

   Linear regression                                Number of obs     =      5,694
                                                    F(18, 5675)       =    2162.50
                                                    Prob > F          =     0.0000
                                                    R-squared         =     0.8677
                                                    Root MSE          =     .68405
```

HCLMP_201819	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
HPY1619Y3R1	-.1282491	.0214645	-5.97	0.000	-.1703277	-.0861705
ThirtySix_months	-1.039601	.0661408	-15.72	0.000	-1.169262	-.9099399
HPY1619Y3R2	-.7634947	.1025639	-7.44	0.000	-.9645591	-.5624304
ThirtyThree_months	-.3163568	.0607258	-5.21	0.000	-.4354026	-.197311
HPY1619Y3R3	1.472777	.0950386	15.50	0.000	1.286465	1.659089
Thirty_months	-.2377245	.0649715	-3.66	0.000	-.3650935	-.1103555
HPY1720Y2R1	-.0619301	.0214906	-2.88	0.004	-.1040599	-.0198002
TwentyFour_months	-.0434395	.0303164	-1.43	0.152	-.1028712	.0159921
HPY1720Y2R2	-.0398523	.0248844	-1.60	0.109	-.0886352	.0089305
TwentyOne_months	.1785094	.0451948	3.95	0.000	.0899103	.2671085
HPY1720Y2R3	.1376492	.0547113	2.52	0.012	.0303941	.2449043
Eighteen_months	.2268875	.0447856	5.07	0.000	.1390906	.3146845
HPY1821Y1R1	.214349	.0826177	2.59	0.009	.0523868	.3763112
Twelve_months	-.7840718	.0676717	-11.59	0.000	-.9167341	-.6514094
HPY1821Y1R2	.0910662	.1051575	0.87	0.387	-.1150827	.2972151
Nine_months	-.155734	.0560253	-2.78	0.005	-.2655649	-.045903
HPY1821Y1R3	.1693544	.0763174	2.22	0.027	.019743	.3189657
Six_months	-.0614797	.0358789	-1.71	0.087	-.131816	.0088566
_cons	1.117065	.148795	7.51	0.000	.8253699	1.40876

13.2 Analysis of network capacity allocated during ARR allocation process

To understand the extent of under-allocation of network capacity to load in the ARR/FTR process, LEI analyzed the share of network capacity being allocated to load during the ARR allocation process using two methods.

1. **ARR MW relative to net MW sold in the FTR annual auction**

   This analysis compares the MW allocated to load versus MW sold to all market participants. We wanted to understand the difference in the system capacity allocated in the ARR process versus the system capacity sold in the annual FTR auction.

   Net FTRs auctioned in an annual auction is defined as the amount of FTRs bought less the amount of FTRs sold over the four rounds of auctions. We used the net FTR auctioned as a metric because someone who bought an FTR path could sell it to another buyer, and in such a case, the total MW of FTR sold by PJM would not change.

   The result of the analysis is presented in Figure 87. Over the past six planning periods, total MWs of allocated ARRs, on average, only represent 21% of the Net FTR volume traded. This is a low number if we accept that the goal of ARR allocation process is to distribute as much network capacity as possible to load prior to the FTR auction.

Figure 87. MW of ARR allocated versus net FTR MW auctioned in annual FTR auction

	MW of ARR allocated	Net MW auctioned in FTR (buy trades - sell trades)	% of ARR MW vs Net MW traded
2014/15	73,504	324,630	23%
2015/16	78,360	314,346	25%
2016/17	83,075	350,747	24%
2017/18	97,126	475,273	20%
2018/19	105,851	566,709	19%
2019/20	105,557	578,921	18%
Total	**543,473**	**2,610,625**	**21%**

Source: LEI analysis of data provided by PJM.

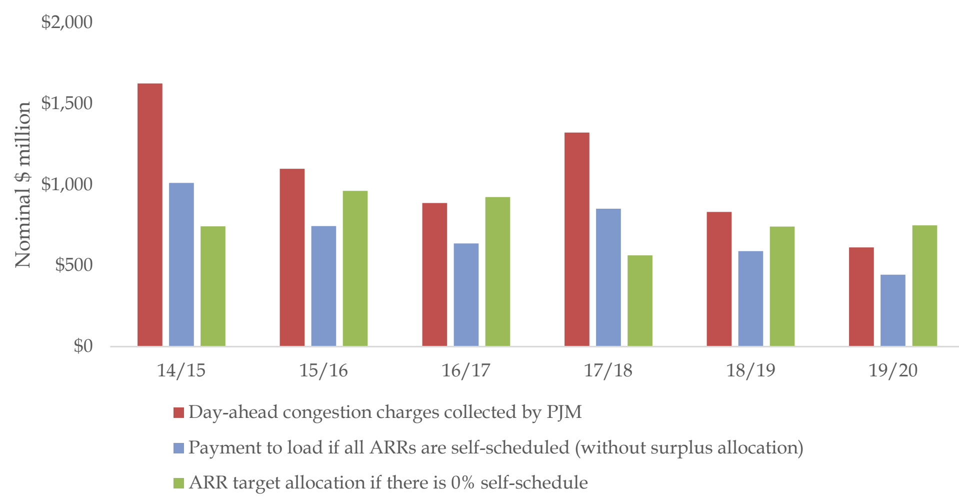
A drawback of this analysis is that two factors may inflate the MWs of net FTRs auctioned in the annual auction, which results in a lower % of ARR MW allocated. First, FTR paths sold in the FTR auction could be counter-flow trades, which should not be considered in an assessment such as this. Second, some of the FTR paths purchased could have source and sink points that are very close to each other from a network perspective and therefore should not be additive when considering the overall amount of transmission network capacity.

LEI cannot isolate these characteristics of the net FTR auctioned variable, as we do not have a full network model of the PJM system. Therefore, readers should note that the metric shown in Figure 88 likely overstates the magnitude of FTR network capacity sold relative to network capacity allocated to ARRs. This analysis shows the difficulty of ascertaining whether the same total network capacity is allocated in ARRs and sold in the annual FTR auctions.[252] Nevertheless, the analysis suggests that there may be a divergence in the quantity of system capacity allocated in ARRs versus what is sold in FTRs.

2. **Congestion charges load would have received if they self-scheduled all ARRs into FTRs, as compared to total congestion charges collected by PJM**

In Figure 88 below, LEI demonstrates the hypothetical results over the last six planning periods from two bookends for load: if all ARRs had been self-scheduled in the annual auction or if all ARRs are held by load. For this analysis, the surplus allocation is excluded because it is a number that is acting as a true-up mechanism that matches the residual congestion charges not yet returned to load after the ARR process. We also excluded balancing charges as we wanted to focus on day-ahead congestion charges and ARR/FTR target allocations, which are both calculated using day-ahead CLMPs.

Figure 88. Congestion returned to load under hypothetical bookends: if all ARRs are self-scheduled or if all ARRs are held by load (0% self-scheduled)



Source: LEI analysis based on data provided by PJM.

[252] LEI attempted to estimate the share of network capacity allocated in the ARR process by reviewing constraints data from the ARR SFT. In the data, LEI observed that there are many network branches that PJM does not monitor but these branches' transmission limit are being impacted by the ARR allocation process. This suggested to LEI that the constraints data would not be effective at measuring network capacity available in the ARR allocation process.

If all ARRs are self-scheduled (blue bar in the figure above), then the dollars received by load would be driven by the actual day-ahead congestion charges collected by PJM for the source and sink points of the ARR paths. The FTR auction price would not affect how much congestion charges load would receive. In contrast, if all ARRs are retained by load (green bar in the figure above), the congestion charges returned to load would be entirely based on the prices emerging from the FTR auction. Whether the eventual day-ahead congestion charges for such paths are higher or lower than the auction price would not matter.

This analysis provides an objective way to measure how much network capacity has been allocated to load in the ARR process. Self-scheduling all ARRs into FTRs would mean the network congestion collected through FTR target allocation would be entirely based on the quantity of ARR allocated. Suppose there is a significant gap between congestion charges collected by PJM and the FTR target allocation for a self-scheduled path. In that case, we can conclude that a material share of network capacity is not allocated to load in the ARR allocation process.

The result shows that in the past six planning periods if all ARRs were self-scheduled, load would have received only 68% of congestion charges PJM collected through the FTR target allocations generated by ARR paths. This means a material part of congestion charges collected by PJM is not allocated to load directly through the ARR mechanism but would have to rely on other allocation methods (e.g., surplus allocation).

If all ARRs are retained, load would have received 72% of congestion charges PJM collected. However, this higher average number (relative to the 68% under all ARRs self-scheduled) only means that the FTR auction on average over-priced ARR paths, this does not indicate how much network capacity was allocated load.

The drawback of this metric is that it is a dollar value-based metric, not an MW-based metric. Therefore, we cannot determine what physical percentage of the network capacity is allocated to load in the ARR allocation process.

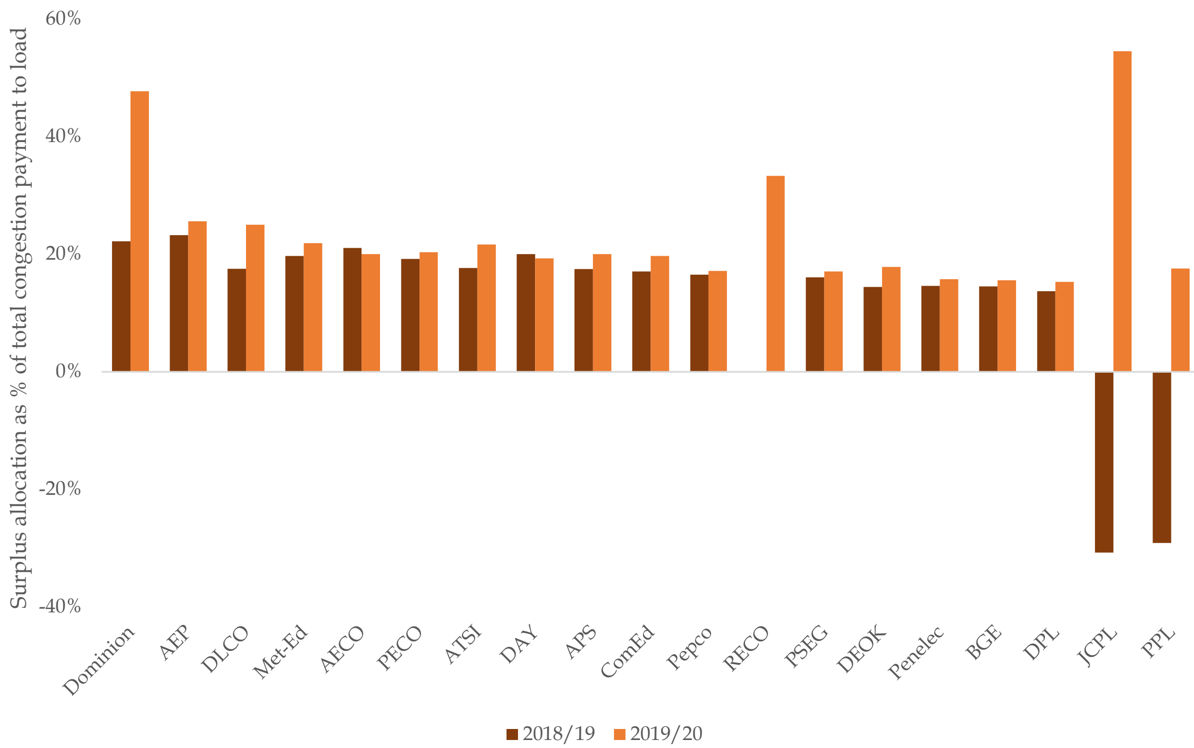
13.3 Surplus and balancing charges as a percentage of congestion charges returned to load

In Section 6.3.2, we stated that the surplus allocation had been a material share of congestion charges returned to load. In aggregate, across PJM, this ratio has been at 18% in the 2018/19 planning period and 20% in the 2019/20 planning period.

When looking into a more detailed allocation by transmission zone, as presented in Figure 89, the share of surplus allocated to each transmission zone compared to the zonal congestion charges returned to load bounces around. While surplus allocation is always a positive value, some zones have a negative ratio. This is because the zone itself has a net negative congestion charge returned to load. This is possible because ARR target allocation can be negative and balancing and M2M charges can also be negative. Therefore, when the net congestion charges paid to a transmission zone are negative, a positive surplus allocation to the transmission zone would result in a negative surplus allocation as a ratio to the congestion charges paid to the transmission zone.

The range of surplus ratios across the transmission zones is -31% to 23% in 2018/19, and 15% to 55% in 2019/20. Interestingly, the zone with the lowest ratio in 2018/19 becomes the zone with the highest ratio in 2019/20. The reason is that that zone has a minimal net congestion charges returned, to begin with. Therefore, a small positive surplus allocation would already contribute a large swing in its total congestion returned.

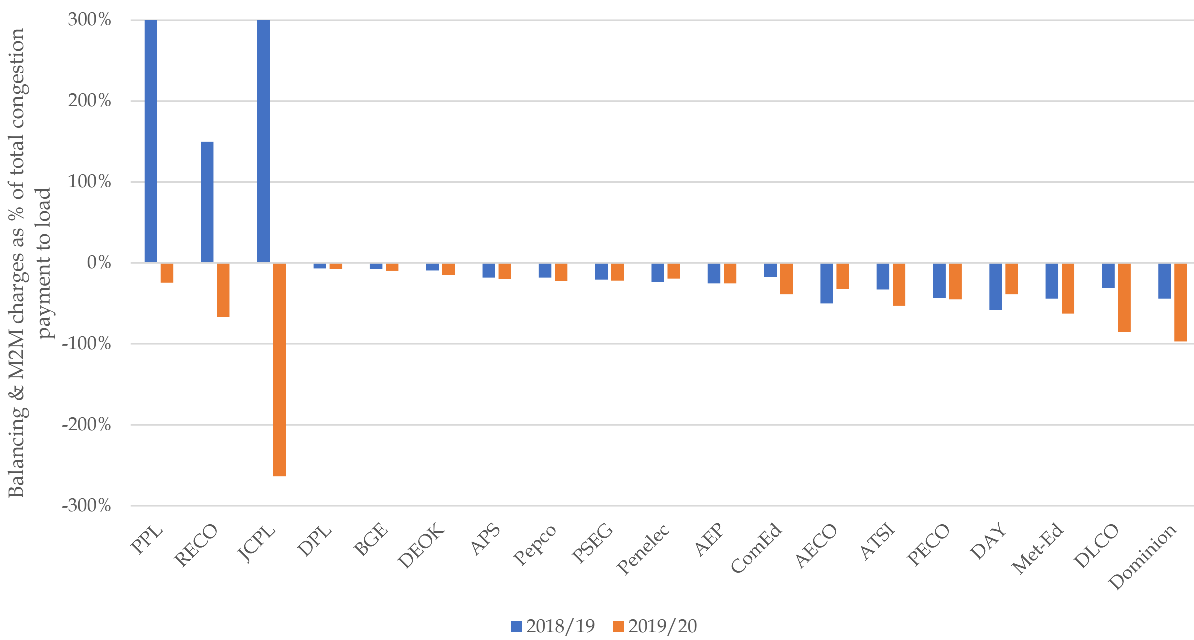
Figure 89. Share of surplus allocation in congestion charges returned to load



Source: LEI analysis of data provided by PJM.

We also analyzed another metric - M2M charges as a percentage of congestion charges returned to load by transmission zone. We looked into this ratio because balancing and M2M charges because of the allocation of those charges, Balancing and M2M charges are charged to load based on real time load and real time export. Although this allocation mechanism is based on the principle of cost causation and cannot be labeled as "socialized," it is still a congestion charge returned to load using a rules-based and non-ARR mechanism and therefore worth understanding how much it impacts total congestion returned to load on a zonal basis. The results are presented in Figure 90.

Figure 90. Balancing and M2M charges as a percentage of congestion charges returned to load



Source: LEI analysis of data provided by PJM.

The result exhibit extremes between zones. In all transmission zones (except for OVEC, which joined at the end of 2018 and is not shown in the figure), in both 2018/19 and 2019/20, the balancing and M2M charges have been negative. For some transmission zones that have a small ARR credit, to begin with, the balancing and M2M s can be larger than the ARR credits, resulting in a substantial positive or negative ratio. On average, balancing and M2M charges average -23%, and -28% of total congestion charges returned to load in 2018/19 and 2019/20, respectively.

13.4 Difference in day-ahead congestion returned to load if load retained ARRs vs. self-schedule, by zone

In Section 6.6 and in Section 13.2, we compared whether ARR holders would receive more congestion payments (excluding surplus allocation and balancing and M2M charges) under two hypothetical bookends: if they retained all the ARRs or self-schedule all ARRs into FTRs.

In this section, we dive deeper into this same analysis but on a transmission zone basis. The results are shown in Figure 94 in table format. For each transmission zone, we calculated how much ARR target allocation the zone would have received if all the ARRs are retained and compared it (subtracted) the FTR target allocation of the zone if all ARRs are self-scheduled. If the resulting calculation yields a positive number, then that zone would have received a higher congestion payment by retaining its ARRs. The result show that in years where load (on a PJM system-wide basis) would receive more target allocation by self-scheduling (2014/15 and 2017/18), more than a third of the zones would have been better doing the opposite – i.e., retaining their ARRs.

Figure 91. Congestion charges returned to load through holding all ARR vs. self-scheduling all ARRs, by transmission zone

Zone	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Average
AECO	(2,394,693)	(343,314)	4,256,346	4,444,888	(8,702,472)	4,888,102	358,143
AEP	(68,890,049)	96,009,060	54,182,351	(100,542,674)	56,832,212	103,750,272	23,556,862
APS	(33,398,291)	40,747,652	42,039,055	(43,133,188)	18,930,575	29,304,994	9,081,800
ATSI	(10,250,218)	38,629,935	14,028,303	(40,736,639)	(1,051,206)	8,796,515	1,569,448
BGE	(45,694,818)	(63,226,101)	44,640,476	(31,522,806)	20,980,525	12,348,949	(10,412,296)
COMED	(72,259,441)	(119,017,889)	(9,680,647)	26,454,858	57,024,885	24,399,546	(15,513,115)
DAY	(1,562,613)	(1,082,051)	2,550,764	(8,765,454)	(4,151,741)	5,679,192	(1,221,984)
DEOK	(7,062,454)	(5,990,104)	6,034,358	(60,404,640)	3,644,281	13,317,050	(8,410,251)
DUQ	(257,737)	805,949	1,664,681	(7,789,188)	1,820,931	(2,638,094)	(1,065,576)
DOM	9,163,608	43,361,622	51,893,928	14,982,987	12,387,652	34,569,120	27,726,486
DPL	(68,338,230)	7,078,656	8,812,697	(186,426)	(20,523,330)	19,621,869	(8,922,461)
EKPC	1,143,085	2,622,221	261,624	2,619,286	(1,494,076)	(1,562,538)	598,267
JCPL	1,043,881	20,289,790	4,869,251	1,417,729	445,409	3,891,903	5,326,327
METED	(263,127)	11,138,788	(683,207)	2,759,692	3,120,936	6,462,820	3,755,984
PECO	6,795,247	29,216,907	(45,396)	463,939	3,739,240	7,451,049	7,936,831
PENELEC	(1,542,775)	23,659,350	9,518,115	(7,360,355)	(7,376,015)	6,655,863	3,925,697
PEPCO	3,208,946	10,290,038	19,395,992	(10,093,865)	11,791,901	6,999,074	6,932,014
PPL	10,931,251	22,982,200	5,735,235	(13,571,674)	(1,027)	(1,767,193)	4,051,465
PSEG	21,607,669	64,808,327	27,731,379	(13,927,814)	5,585,943	24,087,617	21,648,854
RECO	[redacted]	[redacted]	91,361	23,303	(97,253)	254,363	45,296
Total	(258,020,760)	221,981,035	287,296,666	(284,868,040)	152,907,369	306,510,471	70,967,790
Positive zones	7	14	17	8	12	17	14
Zone count	19	19	20	20	20	20	20
% of positive zones	37%	74%	85%	40%	60%	85%	70%

Note: Positive number means paying to load higher if the transmission zone held on to their ARRs. This analysis excludes surplus allocation and balancing, and M2M charges.

Source: LEI analysis of data provided by PJM.

Another observation is that there are zones that would have been better off in all years examined by retaining all their awarded ARRs, such as the Dominion zone. In contrast, no zone would have been more profitable by self-scheduling in all years.

13.5 Percentage of ARRs (in MW) that load self-scheduled

In Section 8.3, we stated that, on average, only 30% of ARRs have been self-scheduled. In this analysis, we break down the self-scheduling trend on a transmission zone basis. Figure 92 presents a table that shows the MW of self-scheduled ARRs as a percentage of MWs of ARRs allocated to each transmission zone in the past six planning periods. The figure shows that the ratio of self-scheduled ARRs differs drastically between transmission zones. Some transmission zone consistently self-schedule most of their ARRs (e.g., Dominion), while some zones rarely self-schedule any ARRs (e.g., AECO and PSEG). There are also zones that started with a high self-schedule ratio but have self-scheduled less ARRs over time, such as ATSI and EKPC.

Figure 92. MW of self-scheduled ARR as % of MW of ARRs allocated by transmission zone

MW % SS						
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AECO	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%
AEP	65.2%	55.9%	52.0%	53.0%	50.6%	55.3%
APS	54.3%	31.4%	28.0%	22.0%	31.5%	34.1%
ATSI	52.7%	36.1%	21.0%	0.0%	0.1%	0.1%
BGE	6.2%	0.9%	8.3%	6.3%	1.9%	5.6%
COMED	6.9%	12.5%	9.9%	10.4%	9.1%	3.8%
DAY	0.0%	6.3%	8.7%	0.0%	0.0%	2.9%
DEOK	22.9%	16.4%	16.9%	13.5%	15.2%	12.9%
DUQ	2.7%	2.6%	3.4%	0.7%	0.7%	0.7%
DOM	89.2%	88.9%	91.2%	92.7%	85.8%	94.0%
DPL	3.6%	1.9%	2.5%	14.7%	10.6%	16.5%
EKPC	48.2%	43.0%	56.7%	29.1%	1.2%	3.8%
JCPL	0.4%	0.4%	0.3%	0.1%	0.0%	0.4%
METED	2.5%	3.2%	2.5%	3.2%	1.7%	3.9%
PECO	1.3%	0.1%	2.2%	0.4%	0.9%	1.4%
PENELEC	13.7%	17.3%	7.4%	7.0%	7.3%	11.3%
PEPCO	8.9%	2.0%	6.2%	3.0%	3.8%	5.4%
PPL	1.8%	0.2%	2.9%	0.8%	0.3%	3.8%
PSEG	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
RECO			0.0%	0.0%	0.0%	0.0%

Source: LEI analysis of data provided by PJM.

One additional observation is that the level of self-scheduling does not appear to correlate with whether load would have been receiving more or less the target allocation depending on whether they retain their awarded ARRs or self-schedule the ARRs. This observation suggests two further points:

1. It is challenging for load to predict whether the ARR target allocation or FTR target allocation would be high or low when load has to decide whether to retain their ARRs or self-schedule, due to the ex-ante nature of the settlement and the price taking requirement; and

2. Load may not be necessarily trying to profit-maximize through the ARR/FTR mechanism. Instead, their decisions to retain ARR or self-schedule are more likely driven by their hedging strategy and the composition of their load serving obligation and bilateral contracts. Therefore, some LSEs may want to self-schedule more if they are facing a variable congestion risk, while other LSEs may want to lock into a fixed price if their contracts are also based on a fixed price. An efficient market design should accommodate various legitimate business strategies.

13.6 Likelihood of obtaining a negative value ARRs versus having negative FTR target allocation when self-scheduling

As discussed in Section 6.5, the dual system of property rights provides load an opportunity to obtain a fixed credit[253] about a year in advance of the spot market instead of a variable congestion charge (which will be known only after the day-ahead energy market settles).

While in theory self-scheduling would provide load a better hedge if the ARR path matches the source and sink points of a bilateral contract (because the variable cash flow would match the cash flow of the bilateral contract), in practice only 30% of awarded ARRs have been self-scheduled. One possible reason for the relatively low level of self-scheduling may be that loads are "loss adverse" and holding a FTR path is perceived as risky. Therefore, LEI analyzed the frequency of a negative payout to load if ARR paths were held (Figure 93) versus self-scheduled (Figure 94). The results show that holding ARRs results in a lower frequency of negative target allocations as compared to self-scheduling. While this cannot directly prove that load tends to hold on to their ARRs instead of self-scheduling because of risk aversion, it does provide one possible explanation of the large share of ARRs not being self-scheduled, which in turn suggests that hedging may be an important element of the ARR/FTR construct for load.

Figure 93. Percentage of ARR MW that would have negative target allocation if they are held as ARRs

% MW	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AECO	5%	8%	1%	10%	1%	0%
AEP	0%	1%	1%	5%	2%	3%
APS	0%	0%	0%	0%	0%	0%
ATSI	3%	0%	2%	12%	0%	35%
BGE	1%	1%	1%	0%	0%	1%
COMED	2%	0%	0%	5%	2%	8%
DAY	6%	2%	1%	2%	0%	1%
DEOK	1%	0%	4%	0%	0%	6%
DUQ	7%	3%	2%	55%	1%	35%
DOM	0%	9%	4%	9%	14%	3%
DPL	0%	0%	2%	0%	5%	1%
EKPC	20%	0%	55%	59%	77%	0%
JCPL	4%	0%	5%	8%	3%	2%
METED	3%	6%	6%	8%	11%	1%
PECO	2%	0%	5%	6%	1%	2%
PENELE(	1%	3%	26%	12%	2%	2%
PEPCO	0%	47%	6%	15%	25%	5%
PPL	4%	10%	10%	39%	26%	9%
PSEG	0%	0%	4%	1%	7%	1%
RECO	[redacted]		0%	100%	69%	20%
Total	2%	5%	3%	10%	6%	6%

Source: LEI analysis of data provided by PJM

[253] Or fixed charge, if the ARR path turns out to be of negative value.

Figure 94. Percentage of ARR MW that would have negative target allocation if they are self-scheduled

% MW	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AECO	21%	47%	8%	17%	7%	18%
AEP	6%	9%	17%	7%	3%	21%
APS	0%	1%	0%	1%	3%	11%
ATSI	3%	26%	15%	28%	7%	33%
BGE	5%	4%	3%	2%	6%	17%
COMED	6%	1%	2%	7%	10%	37%
DAY	1%	7%	28%	5%	3%	11%
DEOK	6%	6%	9%	1%	7%	5%
DUQ	14%	14%	31%	27%	5%	5%
DOM	21%	6%	4%	76%	0%	25%
DPL	1%	3%	11%	1%	3%	22%
EKPC	100%	40%	27%	46%	3%	0%
JCPL	0%	74%	68%	30%	14%	20%
METED	7%	30%	22%	15%	17%	47%
PECO	61%	31%	4%	28%	9%	19%
PENELE(	2%	48%	13%	1%	11%	47%
PEPCO	56%	39%	18%	19%	4%	27%
PPL	76%	45%	36%	12%	33%	37%
PSEG	0%	35%	16%	6%	20%	51%
RECO	[redacted]		0%	96%	52%	10%
Total	12%	28%	17%	16%	9%	26%

Source: LEI analysis of data provided by PJM.

13.7 Profitability of gen-to-gen versus non-gen-to-gen paths

In Section 6.9, we presented the breakdown of net profits earned by non-load over the last six years, planning years 2014/15 to 2019/20. Separately, in Figure 38 in Section 6.10, we presented how load and non-load participate in gen-to-gen and non-gen-to-gen trades. In this section, we present additional details for these transactions.

For all transactions cleared in the annual FTR auctions from 2014/15 to 2019/20, LEI first categorized trades by load versus non-load (defined by whether the market participants are classified as an LSE or not). We also categorized these trades by path, gen-to-gen or non-gen-to-gen (defined by whether both the source and sink node of the FTR path is a generator bus based on the "pnode definition" list provided by PJM to LEI).

Therefore, each transaction can fall into one of the four categories: load gen-to-gen, non-load gen-to-gen, load non-gen-to-gen, and non-load non-gen-to-gen. For each of these categories, LEI aggregated FTR results and calculated an aggregate cost (i.e., auction revenue), an aggregate net profit, and based on the net profit divided by the costs, the profitability rate of these trades.

Note that the "cost" of an FTR path is defined as the clearing price of the FTR path times the MW cleared. This means the "costs" of non-gen-to-gen paths for load are not reflective of how much load actually paid to purchase the paths, because self-scheduled ARR paths would notionally have a "cost," but in reality, load would not pay any proceeds to purchase those FTR paths.

Instead, the "cost" to load for such paths is the foregone opportunity cost of ARR target allocation that it would have otherwise received if they held on to the ARRs. To better understand the scale of this opportunity cost, LEI also calculated the size of this component of "cost" for load non-gen-to-gen paths as a separate line item. The results of this analysis are presented in Figure 95 (for non-load trades) and Figure 96 (for load trades).

Figure 95. Costs and net profit for gen-to-gen and non-gen-2-gen trades done by non-load

	Gen2gen path non-load auction revenue	Gen2gen path non-load net profit	*Non-load profitability on Gen2gen paths*	Non-Gen2gen path non-load auction revenue	Non-Gen2gen path non-load net profit	*Non-load profitability on non-Gen2gen paths*
2014/15	60,849,064	251,835,855	*413.9%*	171,917,603	215,780,847	*125.5%*
2015/16	197,945,662	(29,818,432)	*-15.1%*	151,598,074	109,588,756	*72.3%*
2016/17	26,458,831	94,062,578	*355.5%*	266,611,338	(23,164,441)	*-8.7%*
2017/18	47,360,823	239,510,654	*505.7%*	152,860,946	242,147,923	*158.4%*
2018/19	91,335,486	129,818,270	*142.1%*	307,751,291	53,319,588	*17.3%*
2019/20	174,734,988	96,029,730	*55.0%*	267,163,851	(38,791,043)	*-14.5%*
Average	99,780,809	130,239,776	*130.5%*	219,650,517	93,146,938	*42.4%*

Source: LEI analysis of data provided by PJM.

Figure 96. Costs and net profit for gen-to-gen and non-gen-2-gen trades done by load

	Gen2gen path load auction revenue	Gen2gen path load net profit	*Load profitability on Gen2gen paths*	Non-Gen2gen path load auction revenue	Non-Gen2gen path load net profit	*Load profitability on non-Gen2gen paths*	Non-gen2gen path cost in form of opporunity cost to load
2014/15	6,795,238	10,722,046	*157.8%*	509,055,438	354,061,759	*69.6%*	278,739,718
2015/16	308,976,337	(268,247,295)	*-86.8%*	277,741,475	(3,247,533)	*-1.2%*	334,248,824
2016/17	(1,221,255)	(6,158,693)	*504.3%*	617,152,644	37,223,699	*6.0%*	301,090,667
2017/18	11,886,698	32,926,637	*277.0%*	330,112,104	241,680,474	*73.2%*	157,640,997
2018/19	7,852,391	12,724,064	*162.0%*	415,652,082	24,504,136	*5.9%*	195,899,454
2019/20	15,486,407	(194,411)	*-1.3%*	387,160,758	(91,934,511)	*-23.7%*	228,994,437
Average	58,295,969	(36,371,275)	*-62.4%*	422,812,417	93,714,671	*22.2%*	249,435,683

Source: LEI analysis of data provided by PJM.

Although load suffers from a net loss in gen-to-gen trades while non-load earns a net profit in gen-to-gen trades, LEI does not think it is appropriate to conclude that load is disadvantaged in gen-to-gen trades relative to non-load.

The reason is that almost all the losses for load in gen-to-gen trades occurred in 2015/16. Before 2015/16 (i.e., in 2014/15), load participation in gen-to-gen paths was small, and at the same time, 2014/15 is a highly profitable year for non-load in gen-to-gen paths (over 400% profit). Note that 2014/15 was the year with record hard winter peak demand in PJM, and such high demand results in higher-than-expected congestion (and therefore FTR profitability). One possible explanation of losses made by load in gen-to-gen trades is that seeing the high profit made by non-load in 2014/15, some load decided to increase its exposure in gen-to-gen paths and over-paid for such paths. 2015/16 turns out to be a year with lower levels of congestion, and therefore load may not have been able to fully recoup on its expectations. LEI views such potential events as regular market dynamics and is not reflective of a structural issue in FTR auction.

13.8 Details relating to pricing of FTR options

In Section 6.11, we identified that some FTR options sold at $0/MW or at no premium over the obligation product of the same FTR path. We believe these sales would reflect underpricing of FTR options. Therefore, in Section 8.6, we recommended that the FTR market-clearing engine should be enhanced to eliminate such underpricing.

In this section, we will discuss the magnitude of underpriced options in past FTR annual auctions and the options clearing logic of the current PJM FTR market-clearing engine.

In PJM Manual 06 Section 6.2, it is stated that "[t]he clearing price of an FTR Option Buy Bid will never be less than zero" and "[t]he clearing price of an FTR Option will always be greater than or equal to the clearing price of an FTR Obligation for the same path." Also, "[t]he clearing price of an FTR Option is a function of the shadow price of each binding constraint and cannot be computed directly from nodal prices."

LEI reviewed all options cleared in the annual FTR auction from 2014/15 to 2019/20 and tallied the number of options that cleared at $0, and options that cleared at the same price as the obligation on the same path (referred to as "no premium" options). LEI then calculated the net profits of these options. The results are presented in Figure 99.

Figure 97. Volume and net profit of underpriced options

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MW of $0/MW options cleared	607.10	21.30	32.50	-	183.70	52.00
Net profit from $0/MW options	-	-	-	-	-	-
MW of "no premium" options	954.40	1,782.50	1,141.50	1,171.90	3,488.40	1,640.70
Net profit "no premium" options ($)	173,626.88	7,054,045.44	(220,037.00)	(14,604.11)	99,569.32	(3,738.93)

Source: LEI analysis of data provided by PJM.

While all $0/MW options did not end up with positive net profits, "no premium" options have been profitable in the aggregate in three of the last six years. But it should be emphasized that the main concern should not be whether these options resulted in a net profit – the concern is that the existence of these options presents an arbitrage opportunity for participants to earn a risk-free profit that should not exist in a well-functioning market. Therefore, LEI recommends a review of the market-clearing engine and adjustments, to eliminate such opportunities from occurring, even though the size of net profit earned by these underpriced options has historically been small.

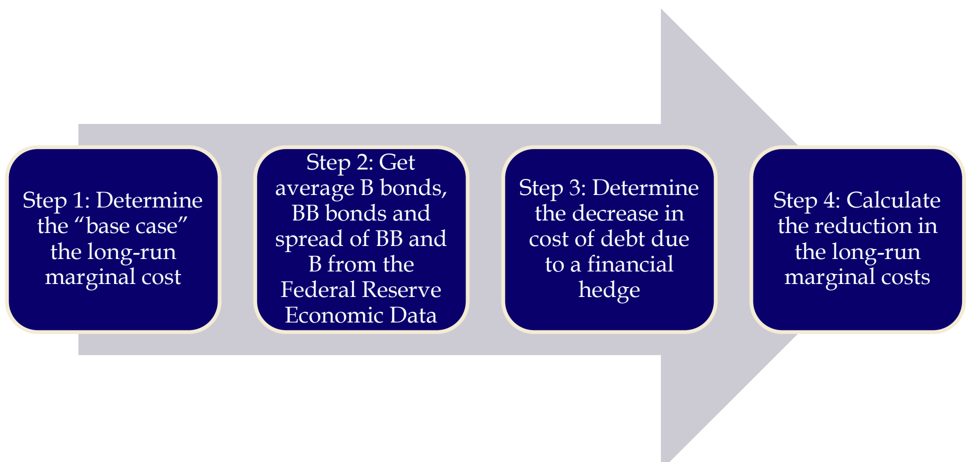
13.9 Illustrative estimates of longer-term benefits

As discussed in Section 6.13.2.3, LEI estimated the longer-term benefits of having a liquid forward market. This Appendix provides an explanation of how LEI calculated the benefits associated with having a lower run marginal cost of supply facilitated by hedging in the forward markets, the hypothetical "what if" benefits for retail providers from having liquid forward markets for hedging, and the impact of bid-ask spreads on transaction costs in the forward markets.

13.9.1 Illustrative analysis of the benefit associated with lower run marginal costs of supply in PJM

LEI calculated the reduction in the benefit of a reduced LRMC by following the steps in Figure 98. Using the assumptions based on the PJM's filing for the periodic review of variable resource requirement curve shape and parameters to FERC on October 12, 2018[254] ("PJM October 2018 filing") and the 2019 total load and percentage that gas plants were price setting were based on the 2019 SOM. LEI determined the "base case" long-run marginal costs. Figure 99 below shows the assumptions used for each variable.

Figure 98. Steps to calculate the reduction in the long-run marginal costs due to the lower cost of debt



Second, LEI looked at the B and BB US High Yield Index Effective Yield data from the Federal Reserve Economic Data.[255] This is also the data used in the PJM October 2018 filing.[256] PJM's October 2018 filing based the cost of debt of 6% on merchant generators that would have a credit rating somewhere between B and BB.[257] Using this approach, LEI looked at the 3-year average of

[254] PJM Interconnection LLC. Docket No. ER19-105-000. "Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters." October 12, 2018.

[255] Available online at: https://fred.stlouisfed.org/series/BAMLH0A1HYBBEY and ttps://fred.stlouisfed.org/series/BAMLH0A2HYBEY

[256] PJM Interconnection LLC. Docket No. ER19-105-000. "Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters." Attachment D, Affidavit of M. Gary Helm. October 12, 2018. p. 3.

[257] PJM Interconnection LLC. Docket No. ER19-105-000. "Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters." Attachment D, Affidavit of M. Gary Helm. October 12, 2018. Pp. 2-3.

B, BB, and the spread between B and BB. LEI used the average of the most recent years (2017 to 2019) , which is the 1.57% spread as shown in Figure 99.

Figure 99. Assumptions used for the cost of new entry for a combined cycle gas plant

Description	Formula	(i) Base Case	Assumptions/Notes
Cost of debt (%)	a	6.00%	PJM filing
Effective Charge Rate (%)	b	11.60%	Formula
Overnight costs ($/kW)	c	$ 785	PJM filing
Levelized capital costs ($/kW)	d = b x c	$ 91.0	Formula
Difference in levelized capital costs ($/kW)	e = Base Case (d) - Scenario (d)		Formula
Load factor	f	75%	LEI assumption
Levelized CONE ($/MWh)	g = e x f		Formula
Load in PJM (TWh)	h	772	2019 SOM
% Gas sets price (%)	i	69.4%	2019 SOM
Load of gas in PJM (TWh)	j = h x i	536	Formula
Annual Savings based on notional load in PJM ($ millions)	**k = (g x j)**		Formula

Note: Items (a) and (i) above are for the Base Case only. These will change in our "scenario cases" as discussed below.

Sources: PJM filing (October 12, 2018), 2019 State of the Market Report, and LEI.

Third, LEI estimated the decrease in cost of debt if a project has a financial hedge. Credit rating agencies assess the stability or volatility of a project's revenue stream by considering the degree of contractual support underpinning the revenues and the sources of revenues. According to Moody's, for example, generation projects with contractual support will receive a stronger score than projects with merchant exposure because cash flows are significantly less volatile for the former.[258] Also, S&P Ratings states that "a plant that has no contracts with off-takers or hedges could be assessed as having high market exposure."[259]

Credit ratings correlate negatively with the cost of debt. This means that cost usually increases as ratings decline. For this illustration, LEI conservatively assumed that cost of debt would be lower by a quarter-notch to half- notch for merchant generation projects with hedging. Therefore, using the 2017-2019 average spread between B and BB of 1.57% (as seen in the figure below), the change in the cost of debt for credit improvement of a quarter-notch would be equal to 0.39%, and an improvement of a half-notch would be equal to 0.78%.

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[258] Moody's. "Power Generation Projects Methodology." July 31, 2020.

[259] S&P "Project Finance Operations Methodology." <https://www.standardandpoors.com/en_US/web/guest/article/-/view/sourceId/8687748>

Figure 100. Three-year average of B, BB, and spread between B and BB

Average (in percentage)			
Year	BB	B	Spread
2015	6.17	8.64	2.47
2016	5.20	7.39	2.19
2017	4.33	5.70	1.37
2018	5.15	6.56	1.41
2019	4.45	6.38	1.92
2020	4.63	6.56	1.93
Avg. (2015-2017)	5.23	7.24	2.01
Avg (2016-2018)	4.89	6.55	1.65
Avg (2017-2019)	4.64	6.21	1.57

Source: Federal Reserve Economic Data.

Figure 101. Summary of the potential long run benefits to load from reduced LRMCs ($ million)

		Frequency with which new CCGTs are directly or indirectly price setting in the long run		
		CCGTs have a 69.4% price setting share	CCGTs have a 50% price setting share	CCGTs have an 80% price setting share
Change in the cost of debt for new CCGT due to hedging	0.39% change in cost of debt (quarter-notch improvement)	$ 138	$ 99	$ 159
	0.78% change in the cost of debt (half-notch improvement)	$ 276	$ 199	$ 318

Source: LEI analysis.

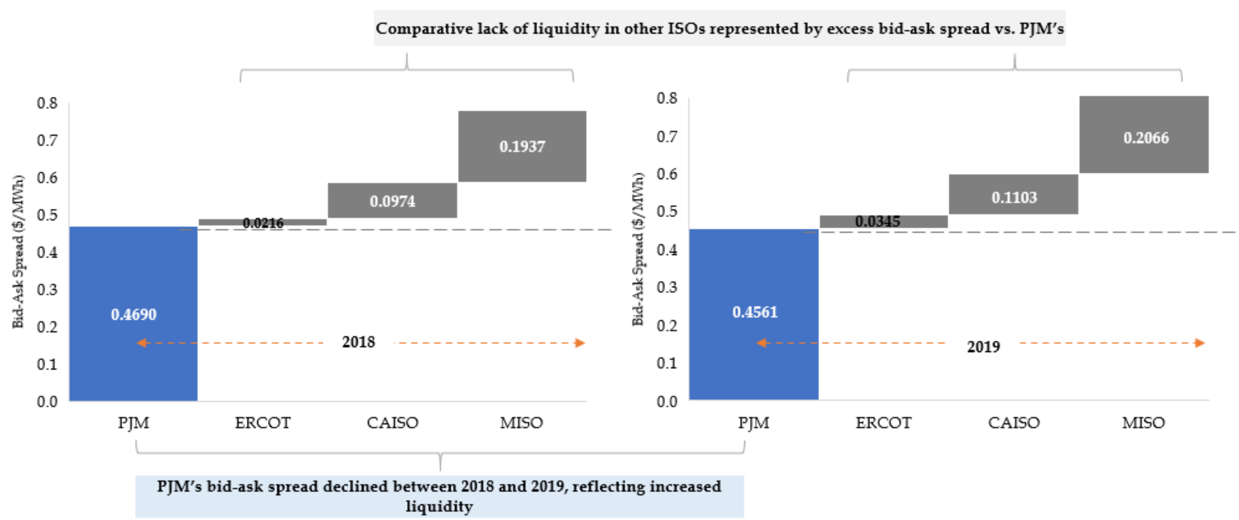
Lastly, LEI calculated the reduction in the LRMC of CCGTs using this lower cost of debt. Using the 2019 load of 772 TWh and the market share of gas setting prices in PJM of 69.4%, LEI estimated that the annual savings due to lower cost of debt ranges between $138 million and $276 million. In addition, using the 772 TWh load and the 50% and 80% gas share[260] in setting all-in market prices, LEI estimated the annual savings due to lower cost of debt ranges between $99 million and $318 million as shown in Figure 101.

[260] According to the 2020 Quarterly State of the Market Report for PJM (January to September 2020), natural gas units were 73.6% of marginal resources, which is higher than in 2019 where gas units were marginal units 69.4% of the time (See Monitoring Analytics, "2020 Quarterly State of the Market Report for PJM: January through September." November 12, 2020. p. 101). Because of this as well as the anticipated turnover in supply (retirements and new entry), LEI used 80%.

13.9.2 Illustrative analysis of the impact of bid-ask spreads on transaction costs in forward markets

As a measure of liquidity, the 'bid-ask spread' relates to market participants' costs when making a transaction. A typical proxy for liquidity is the bid-ask spread, which is the difference between the lowest price for which a seller is willing to sell a megawatt-hour of electricity (i.e., ask) and the highest price that a buyer is willing to pay for it (i.e., bid). As shown in Figure 102, In 2019, PJM's liquid forward markets averaged a bid-ask spread of $0.45/MWh. In comparison, other US RTOs/ISOs had a higher average bid-ask spread, reflecting lower liquidity.[261] This lower liquidity translates into a higher transaction cost for participants in the forward markets, ultimately impacting the overall cost of supply.

Figure 102. Futures bid-ask spreads across ISOs in 2018 – 2019



Source: OTC Global Holdings/SNL, LEI analysis.

To analyze the impact of the increasing cost of losing liquidity, LEI developed a what-if (counterfactual) analysis based on the bid-ask spreads. PJM has had an average bid-ask spread $0.45/MWh to $0.47/MWh in 2018-19, with a standard deviation of $0.21/MWh to $0.22/MWh. PJM's average bid-ask spread in 2018-19 has been $0.19/MWh to $0.21/MWh lower than that of MISO and $0.10/MWh to $0.11/MWh lower than that of CAISO. Based on various empirical

[261] J.P. Morgan Center for Commodities at the University of Colorado Denver Business School. Liquidity Issues in the U.S. Natural Gas Market. September 2019. p. 56.

studies[262,263,264] reviewed on liquidity assessments of commodity markets, one standard deviation in bid-ask spreads is a common metric of analysis. Therefore, LEI incorporated the impact of the observed 'one standard deviation' in PJM's actual bid-ask spreads as an illustrative computation of potential increase in transaction costs if the liquidity of the PJM market was compromised. This value of $0.21/MWh also aligns with the average difference in bid-ask spreads between PJM and MISO. We also tested $0.10/MWh for the lower range of potential changes; this is the observed average difference between the bid-ask spreads in PJM and CAISO.

To properly capture the size of the physical and financial forward markets, LEI adjusted the net load served to reflect current levels of bilateral activity (by deducting spot purchases and self-supply). Estimates of spot purchases were taken from the PJM ARR/FTR White Paper, while the adjustment for self-supply was based on 2019 reported generation for regulated power plants in PJM.[265]

Figure 103. Liquidity assessment on transaction costs in PJM

Liquidity Assessment on Transaction Costs					
Steps in computation		**Source**	**Unit**	**Illustrative Lower Range Change in Bid-Ask Spread**	**Illustrative Higher Range Change in Bid-Ask Spread**
Change in Bid/Ask Spread	(a)	*OTC Global Holdings/SNL*	*$/MWh*	$0.10	$0.21
Financial Futures	(b)	*Nodal Exchange and ICE*	*MWH*	3,843,626,994	3,843,626,994
Bilateral Trades	(c)	*Calculated*	*MWh*	391,822,143	391,822,143
Forward Market Load	(d) = (b) + (c)	-	*MWh*	4,235,449,137	4,235,449,137
Impact of forward market liquidity (change in transaction costs)	**(e) = (a)*(d)**	**-**	**$**	**$423,544,914**	**$889,444,319**

Source: OTC Global Holdings/SNL, ICE and Nodal Exchange, LEI analysis.

Figure 103 shows the impact of a one standard deviation change in the average bid-ask spread reported in PJM for 2019. Load in PJM is benefiting from lower bid-ask spreads, which have been facilitated by liquid and efficient forward markets. Price discovery arising from PJM's FTR auctions support forward market liquidity and efficiency. Illustratively, a $0.10/MWh to $0.21/MWh change in the bid-ask spread would increase transaction costs for forward market

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262 Bjonnes, Geir, Neophytos Kathitziotis and Carol Osler (2016). "Bid-Ask Spreads in OTC Markets", Brandeis University Working Paper Series, 2016-102. March 20, 2016.

263 Roll, Richard, Eduardo Schwartz and Avanidhar Subrahmanyam. "Liquidity and the Law of One Price: The Case of the Futures/Cash Basis." The Journal of Finance, Oct. 2007, Vol. 62, No. 5 (Oct. 2007).

264 Ibikunle, Gbenga, Andros Gregoriou , Andreas G.F. Hoepner, Mark Rhodes "Liquidity and Market efficiency: European Evidence from the World's Largest Carbon Market.". University of Edinburgh.

265 Using the S&P Global database, LEI identified the regulated generation plants in PJM. Based on the database, these plants produced approximately 166 TWh of energy in 2019. LEI assigned this production to load as "self-supply."

activity in the range of $424 million and $889 million a year in PJM. Load benefits from these avoided transaction costs.

14 Appendix F: Case studies

LEI reviewed the ARR/FTR mechanisms of three ISOs/RTOs, namely CAISO, ERCOT, and MISO. Section 7 provides a summary of the comparative analysis of the similarities and differences among these markets. This Appendix provides a more detailed discussion of each ISO/RTO's ARR/FTR auctions, products, and settlement. This Appendix is high level and is not meant to cover all the business rules of each ISO/RTO's ARR/FTR mechanisms.

14.1 CAISO

The CAISO operates the power grid and wholesale electricity market for approximately 80% of California and is overseen by the FERC. The remaining 20% of the state is operated by local balancing authorities and utilities, such as the Los Angeles Department of Water and Power ("LADWP"), and Sacramento Municipal Utility District.[266] SMUD and LADWP are part of CAISO's Energy Imbalance Market ("EIM"). LEI has analyzed the CAISO market as one of the case studies because of the CRR changes that CAISO has introduced in 2018, namely:

- increasing the number of constraints enforced by default in CRR models;
- introducing various reviews to the internal CRR processes, changes to business rules and operational guidance;
- limiting paths available in CRR auctions to only delivery paths (comprised of source and sink pairs that are associated with supply delivery to load);
- updating the reporting requirement for transmission outages to align reporting processes and CRR auction timeline; and
- decreasing the transmission capacity available in the annual CRR process.

14.1.1 Overview of the CAISO market

CAISO operates the DAM and real-time energy market, as well as various ancillary services markets. Following the 1996 FERC Orders Nos. 888[267] and 889[268], and State Legislation (AB 1890),[269] CAISO was incorporated as a non-profit public benefit corporation to play an ISO role.

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[266] California Energy Commission. Map of Balancing Authority Areas in California. February 26, 2015. http://www.energy.ca.gov/maps/serviceareas/balancing_authority.html

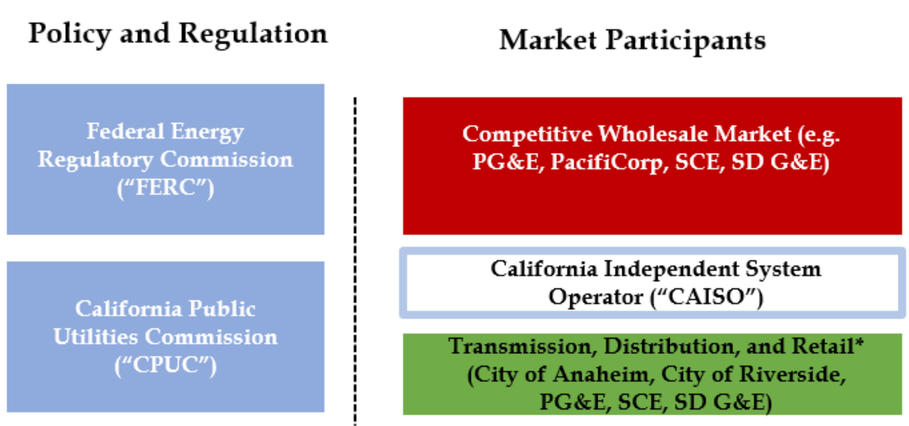
[267] Federal Energy Resource Commission. Order No. 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. April 24, 1996.

[268] Federal Energy Resource Commission. Order No. 889: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct. April 24, 1996.

[269] California 1996 Legislative Service. Assembly Bill 1890: Electricity Utility Industry Restructuring Act. September 23, 1996.

EIM was launched in October 2014[270] allowing CAISO to dispatch resources from generators located in balancing authority areas outside of its service area. The reliability of electric service in California is governed by the 2004 Resource Adequacy policy framework,[271] creating an in-state bilateral spot market for capacity, which is regulated by the California Public Utilities Commission ("CPUC"). CAISO's Department of Market Monitoring[272] ("DMM") reports on the efficiency and effectiveness of the CAISO markets. In addition, the Market Surveillance Committee ("MSC"), an independent body of retained experts, provides commentary and recommendations about the competitiveness of CAISO's administered markets (as described in the tariff) and, more broadly, market design to the CAISO leadership. The Department of Market Analysis and Forecasting tracks and reports the performance of the CRR market in CAISO. CAISO's market structure is depicted in Figure 104 below.

Figure 104. Electricity market structure in California



*Note: These utilities are often referred to as Utility Distribution Companies.

Source: LEI.

CAISO is a much smaller market compared to PJM (79,845 MW installed capacity as of March 2020, compared to PJM's installed generation capacity of 185,189 MW[273]). Figure 104 illustrates key descriptive statistics for CAISO wholesale electricity market. As of March 2020, over 50% of

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270 CAISO. ISO and PacifiCorp Outline EIM Implementation Plans for October 1. September 15, 2014. <https://www.westerneim.com/Documents/ISOandPacifiCorpOutlineEIMImplementationPlans-October1.htm >

271 CAISO. Resource Adequacy. Accessed on October 23, 2020. <https://www.cpuc.ca.gov/ra/>

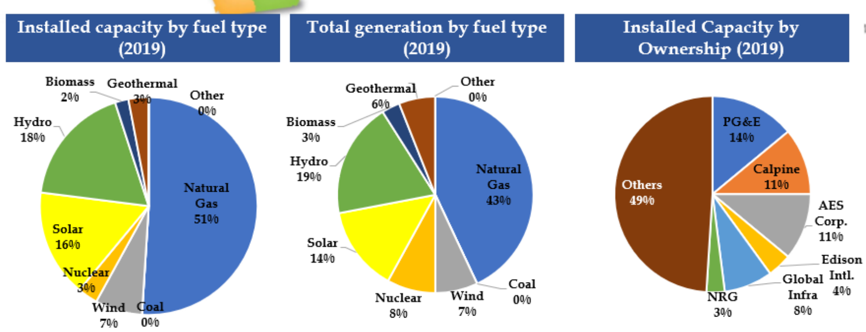
272 The DMM in CAISO can be considered equivalent of an IMM in other ISOs from FERC's point of view.

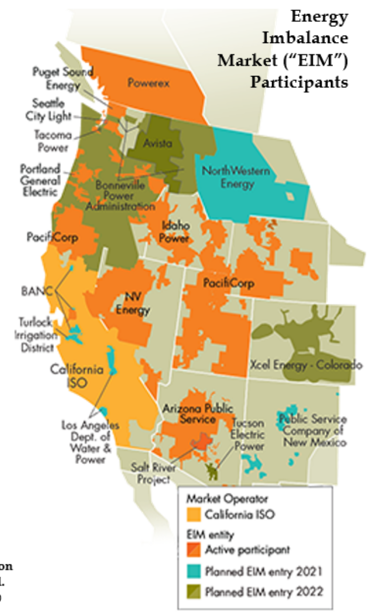
273 Potomac Economics. Monitoring Analytics, LLC. *Q1 State of the Market Report for PJM, 2020.* May 14, 2020., Table 1-1, p. 3.

California's installed capacity is natural gas, followed by hydroelectric generation at 18%, and other renewables (including wind, geothermal, solar, and biomass) at 28%[274] of installed capacity, respectively. However, it should be noted that this installed capacity does not include distributed generation, such as residential solar photovoltaic installations, which have grown significantly in recent years. In comparison to PJM, three Investor-Owned Utilities ("IOUs"), namely Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric participate in CAISO. Under the purview of the CPUC, these IOUs represent a total resource adequacy capacity of about 32,707 MW or 66% of the total average system resource adequacy capacity.[275] Further, any utility-scale solicitations or Requests for Offers ("RFOs"), which are competitive processes conducted by the IOUs, are largely overseen by the CPUC.[276] Therefore, this market design reflects that investment signals originate from a centrally planned decision than market forces. As a result, CAISO's CRR mechanism focuses only on Purpose #1.

Figure 105. Snapshot of the CAISO RTO, 2019

Key facts (2019)	
Installed capacity	79,845 MW
Peak demand	44,301 MW
Generation	200,475 GWh
Transmission lines	26,000 miles
People served	30 million
Area served	80% of land area





Note: Figures exclude out-of-state capacity and generation.

Source: CAISO, California Energy Commission.

[274] On a nameplate basis.

[275] CAISO. *2019 Annual Report on Market Issues and Performance*. June 2020. Table 10.2. p. 263.

[276] CPUC. Utility Scale Request for Offers (RFO). https://www.cpuc.ca.gov/Utility_Scale_RFO/

14.1.2 Overview of the CRR market in CAISO

Unlike PJM, CAISO does not have ARRs. CAISO's CRRs, like PJM's FTRs, are financial rights that are used to hedge forward market congestion costs in the DAM and manage the variability based on LMP. These forward contracts settle in the DAM energy market price as the price difference between two locations.

CRRs are available through the CRR allocation and auction processes facilitated by CAISO.[277] There is also a Secondary Registration System where CRR holders can trade and transfer ownership of CRRs through an electronic bulletin board; however, CAISO is not directly involved in these secondary trades of CRRs.[278] The key objectives[279] of the CRRs in CAISO include:

- to minimize transmission congestion cost uncertainty;
- to allow market participants to 'lock-in' price for transmission usage;
- to encourage competitive energy trading; and
- to enhance energy commerce in the CAISO region.

14.1.3 Evolution of CRRs in CAISO

California's wholesale energy market started with a zonal real-time energy market design (and the market was administered by an entity separate and distinct from the CAISO). In the aftermath of the California energy crisis, the Market Redesign and Technology Upgrade ("MRTU") initiative was launched. This initiative included switching the California wholesale market from the Radial Network Model (i.e., no intra-zonal constraints enforced) to a Full Network Model (all constraints enforced), introducing LMP at each node, creating a DAM, and launching CRRs from source to sink.[280]

Similar to other US RTOs/ISOs, the DAM LMP is composed of marginal cost of energy, marginal cost of congestion at each bus relative to the reference bus, and marginal cost of losses at each bus relative to the reference bus.[281]

In February 2006, CAISO filed the proposed MRTU Tariff that discussed seasonal and monthly transmission rights, under the category of short-term CRRs. In September 2006, the proposal on

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[277] CAISO. *Congestion Revenue Rights*. 2020. <http://www.caiso.com/market/Pages/ProductsServices/CongestionRevenueRights/Default.aspx>

[278] CAISO. *Overview of Congestion Revenue Rights in the New California Energy Market.* March 21, 2006.

[279] CAISO. *Overview of Congestion Revenue Rights in the New California Energy Market.* March 21, 2006. p. 4.

[280] CAISO. *Overview of Congestion Revenue Rights in the New California Energy Market.* March 21, 2006. <https://www.caiso.com/Documents/CRROverviewPresentation.pdf>

[281] CAISO. Fifth Replacement Electronic Tariff. Appendix C. March 01, 2019.

the short-term CRRs was given conditional approval by FERC, and in April 2007 the proposal underwent another re-hearing that resulted in further modifications. MTRU's initial proposal included provisions for long-term CRRs.[282]

Currently, CAISO releases the seasonal available CRR capacity as 75% for annual process and 60% in Tier LT process, respectively, alongside 100% of monthly available CRR capacity in monthly processes.[283] Since October 2019, CAISO is considering extending the CRR market design to EIM entities.[284]

Between 2009 and 2018, CAISO has experienced CRR revenue insufficiency.[285] This prompted the launch of a stakeholder process in 2017 to identify fixes. Following the approval of the FERC, these were introduced starting the 2019 settlement year.[286] These enhancements included modeling improvements, outage practice improvements, and reduction of capacity released in the annual CRR process:

- ***Track 0*** (modeling improvements): discussed the CRR auction enhancements implemented without introducing tariff changes. The proposal includes internal process improvements, changes to business rules, and operational guidance.[287] CAISO implemented the changes in the first half of 2018.[288]

- ***Track 1A:*** discussed CRR auction enhancements implemented with tariff changes. These enhancements included limiting the paths available through the CRR auction to only delivery paths (comprised of source and sink pairs associated with supply delivery to load) and updating the reporting requirement for transmission outages for better

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282 The purpose of LTTRs was to allow flexibility LSEs to accommodate possible future changes, such as engaging in long-term contracts with new renewable energy resources that would be in remote areas distant from customer load centers. Gradual implementation would also allow LSEs to learn how the CRR system works, to optimize their current and future optimal uses of the grid and prevent uninformed long-term decisions. Thus, the LTTR capacity eligibility was capped at 20% of its adjusted load metric in year one, with an increase of 10% per year. The CPUC proposal were subsequently accepted by FERC.

283 CAISO. "Business Practice Manual for Congestion Revenue Rights. v 21." July 25, 2017. p. 66.

284 CAISO. "Extending the Day-ahead Market to EIM Entities, Issue Paper." October 10, 2019. p. 10.

285 FERC. Docket No. ER19-26-000. Washington DC. 2018. p. 3.

286 CAISO. "Report on Results of 2019 Congestion Revenue Rights Updated." June 24, 2020, p. 1.

287 CAISO. "Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal." p. 8.

288 CAISO. "Briefing on Congestion Revenue Rights Performance." July 22, 2022., p. 2.

alignment between the reporting process and CRR auction timeline. FERC approved the proposed structural changes[289] in June 2018.

- ***Track 1B:*** discussed CRR auction enhancements implemented with tariff changes. This included modifying the percentage of capacity released for allocations and auction by decreasing the percentage of the transmission system capacity available in the annual CRR allocation and auction processes from 75% to 65%. FERC approved the proposed structural change[290] in September 2018. CAISO's intent was to reduce the risk by not releasing higher capacity in advance that later becomes unavailable in the DAM due to outages and configuration changes.[291]

CAISO continues to monitor the progress of the implementation of these tracks for the CRR market.

14.1.4 CRR mechanisms

Like PJM, CRRs in CAISO are PTP. The CRR allocation process to LSEs is discussed in Section 14.1.6 below. Other entities (non-LSEs) can also purchase CRRs in the CRR auction administered by CAISO. The CRR processes are separated into the allocation process and auction process. Eligibility for allocation is limited to CRR LSEs, while the auctions are opened to all registered market participants (subject to the posting of sufficient collateral).

The CRR market participants broadly include the load (LSEs), physical generators, marketers, and financial entities. The market participants' performance in the CRR market and the DMM classification of market participants are discussed in Figure 108 on page 202).

Between 2017 and 2019, over 90% of the CRRs sold in the CRR auctions went to non-investor-owned utilities. LSEs have increasingly participated in CRR auctions by selling their allocated CRRs, indicating the dependence on auctions to rebalance the CRR portfolio by managing congestion exposure and risk.[292]

Following the implementation in 2019 of CAISO's CRR revenue sufficiency improvement process, the year-on-year CRR auction results showed a material contraction. CRR auction participation (measured through bid-in volumes) declined by an overall 50% in 2019 from the prior year. The quantity of CRRs cleared in auctions fell by 57%, and net auction revenues

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[289] FERC. Docket No. ER18-1344-000. Washington DC. 2018.

[290] FERC. Docket No. ER19-26-000. Washington DC. 2018. p. 4

[291] CAISO. "CRR Market Analysis Report." May 12, 2020. p. 11.

[292] CAISO. "CRR Market Analysis Report." May 12, 2020. p. 5.

declined by 24% to $63 million in 2019 (as compared to an average of $83 million in 2017 and 2018).[293]

14.1.5 CRR products

CAISO offers CRRs in two forms: CRR Obligations and CRR Options. However, CRR options are currently only available to owners of merchant transmission facilities.[294]

- ***CRR Obligation:*** entitles CRR holder to receive a CRR payment if the congestion in a given trading hour is in the same direction as the CRR obligation and requires a CRR Charge if the congestion in a given trading hour is in the opposite direction of the CRR.

- ***CRR Option:***[295] entitles CRR Holder to receive a CRR payment if the congestion is in the same direction as the CRR option but requires no CRR charge if the congestion is in the opposite direction of the CRR.

CRRs are defined in terms of season (quarters) or months. CRRs are not available for an entire year, although a market participant can be allocated or can seek to purchase a strip of CRRs for all four seasons to given it an annual equivalent. CRRs are also broken down by TOU, namely peak and off-peak. CAISO offers CRR obligations or options in four tenors, including:[296]

- ***Monthly CRR:*** acquired through the monthly CRR allocation or CRR auction processes for one calendar month. The CRR allocation and auction process will be discussed in Section 14.1.6.

- ***Seasonal CRR***: acquired through the annual CRR allocation or CRR auction process on a quarterly basis, as shown below. PJM does not have any seasonal FTRs.
    - season 1: January through March
    - season 2: April through June

[293] CAISO. "CRR Market Analysis Report." May 12, 2020. p. 4.

[294] CAISO. "Business Practice Manual for Congestion Revenue Rights." Version 27. Last Revised: March 27, 2020.

[295] CRR options are only available to project sponsors of a merchant transmission facility that do not elect some form of regulatory cost recovery. These transmission lines are turned over to CAISO and the developer will not receive rate-based recovery of the incurred investment cost. Merchant transmission CRRs are allocated through a separate allocation process (not available through the CRR Allocation and CRR Auction processes) and the CRR quantity allocated must reflect the incremental capacity the project adds to the CAISO grid. *Source: CAISO. Congestion revenue rights training – CRRs Overview. Accessed in October 2020.*

[296] CAISO. "Business Practice Manual for Congestion Revenue Rights." Version 27. Last Revised: March 27, 2020.

    - season 3: July through September
    - season 4: October through December

- ***Long Term CRR***: acquired through the annual CRR allocation process for a term of 10 years and are allocated on a seasonal/quarterly basis.

- ***Merchant Transmission CRR***: acquired through a separate process and only available for merchant transmission facilities for a term of 30 years or the pre-specified intended life of the facility, depending on which is less. This is similar to PJM's IARR.

14.1.6 CRR allocation and auctions

The amount of CRRs that CAISO allocates (and sells, if any CRRs are left over from the allocation process) is determined by the SFT. In addition, CAISO provides a CRR Full Network Model[297] ("FNM") ahead of the monthly and annual auctions to the market participants. The annual process is conducted once a year and begins with four allocation tiers, followed by an auction. The monthly process is conducted 12 times a year and has two allocation tiers, followed by the monthly auction.

The CRR annual process (allocation + auction) is capped at 65% of load and starts around four months before the start of the calendar year. CAISO runs the SFT for each tier of the annual allocation and the annual auction for all seasons and TOU separately, but simultaneously, for a total of eight SFTs (4 seasons, on peak, and off-peak). Only LSEs and Out-of-Balancing Authority Area LSEs ("OBAALSEs") are eligible to participate in the CRR allocation. Each CRR allocation process is based on nominations submitted to CAISO by LSEs and OBAALSES. The CRR allocation process is, therefore, like PJM's ARR nomination and allocation process.

In the annual allocation process, participating LSEs and OBAALSEs submit their historical load data, then CAISO runs the SFT to determine the seasonal CRR eligible quantity for each allocation participant by load aggregation point and TOU period within each of the four seasons. The seasonal CRR eligible quantity is updated after each tier and reflects rights under Transmission Ownership Rights and Existing Transmission Contracts, as well as CRRs allocated in previous years or the previous tiers of the process.

As part of the CRR enhancements and policies implemented in 2019, CAISO eliminated non-delivery paths (as part of phase 1A of the 2019 annual process) and only allowed paths that "follow the natural direction for the delivery of power."[298] This means that only a subset of the source to sink combinations are allowed. By allowing market participants to bid on delivery paths only (and not on non-delivery paths), CAISO believes that this will create more competition and

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[297] CAISO provides the FNM to market participants on demand and upon compliance with applicable Submission Instructions and submittal of a non-disclosure agreement.

[298] CAISO. "CRR Market Analysis Report." Market Analysis and Forecasting. May 12, 2020. p.11.

thus bring the prices closer to the expected day-ahead congestion, which then could improve auction efficiency. Before 2019, market participants can purchase any combination between sources and sinks, even those that are non-delivery paths. [299]

The four tiers of the annual allocation process are described below:

- ***Tier 1*** (also called Priority Nomination Process): only includes CRRs allocated in the previous annual CRR allocation process;

- ***Tier LT***: 9-year extension of what was awarded in Tier 1 up to 50% of the load; and

- ***Tiers 2 and 3:*** remaining CRR up to 65% of the load.

At each tier, CAISO publishes the seasonal CRR eligible quantity, CRR participants submit their nominations, CAISO clears that tier, and publishes the results. After the four tiers are completed, the annual CRR auction begins (described in more detail in Section 14.1.7 below). Figure 106 illustrates the key steps in the annual process.

The monthly CRR allocation and auction processes follow a similar approach to the annual process, with fewer steps/tiers. The monthly process allocates up to 100% of load, after any adjustments for outages and derates, and is based on forecasted load data instead of historical.[300]

CAISO calculates a residual value set aside for the CRR Auctions during both the annual and the monthly allocation process, which will be sold in its respective auction process (the set aside value from the annual allocation process will be made available at the annual auction and the monthly set aside at the monthly auction). The set aside value during the annual process is calculated after tier 2 nominations, and during the monthly process is calculated after tier 1 nominations. The set aside value is 50% of the residual capacity after the nominations at that Tier and takes into consideration any allocated CRR in previous tiers or from previous auctions and Long Term CRRs that are valid for the respective quarter/month and TOU period. For example, 72,328.42 MW was set aside for the 2020 annual CRR auction process alongside 69,875.76 MW for 2021.[301]

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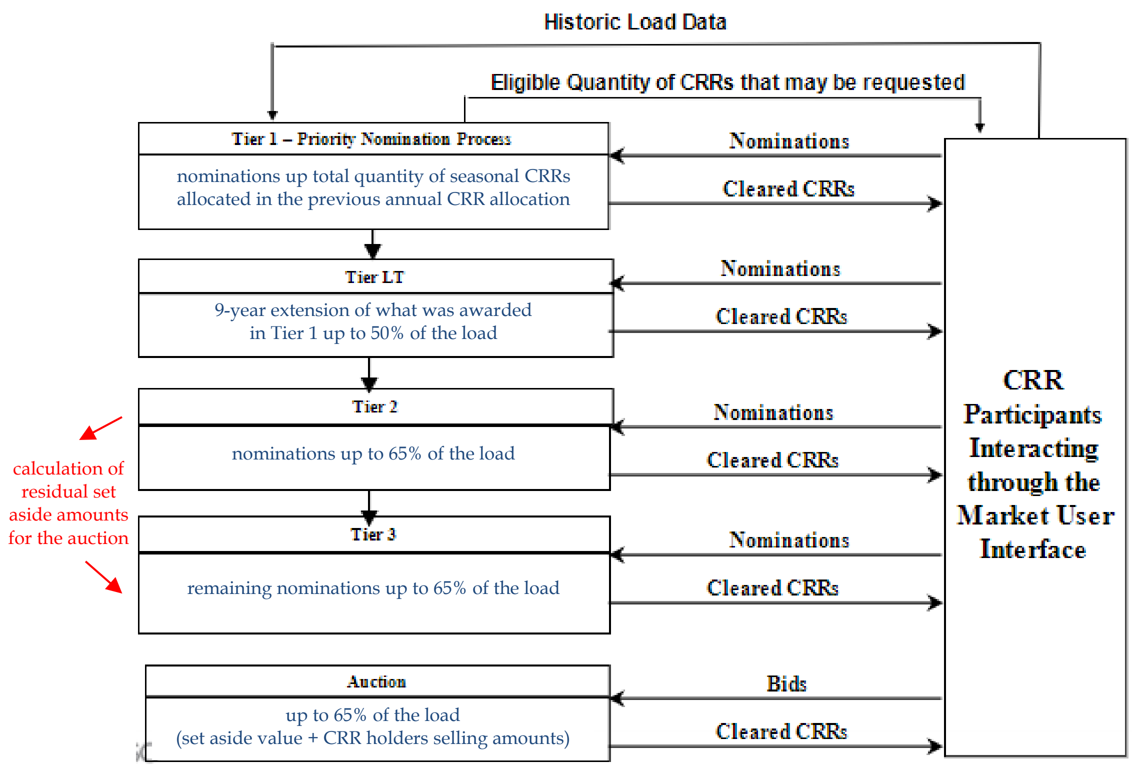
[299] CAISO. "Congestion Revenue Rights Performance Update." Market Surveillance Committee Meeting, General Session March 13, 2020. <http://www.caiso.com/Documents/CongestionRevenueRightsPerformanceUpdate-Presentation-Mar13_2020.pdf>

[300] The monthly process is based on forecasted load except for entities that have load that varies with hydrological conditions. In this case, they can choose to use either historical or forecasted load. Source: CAISO. "Congestion revenue rights training – CRRs Overview." Accessed in October 2020.

[301] CAISO. Market Operations > Products Services > Congestion revenue rights > Current processes > Annual 2020 Set Aside Values published 10/15/2019 and Annual 2021 Set Aside Values published 10/27/2020. <http://www.caiso.com/market/Pages/ProductsServices/CongestionRevenueRights/Default.aspx>

Figure 106. CRR allocation and auction – annual process



Source: CAISO.

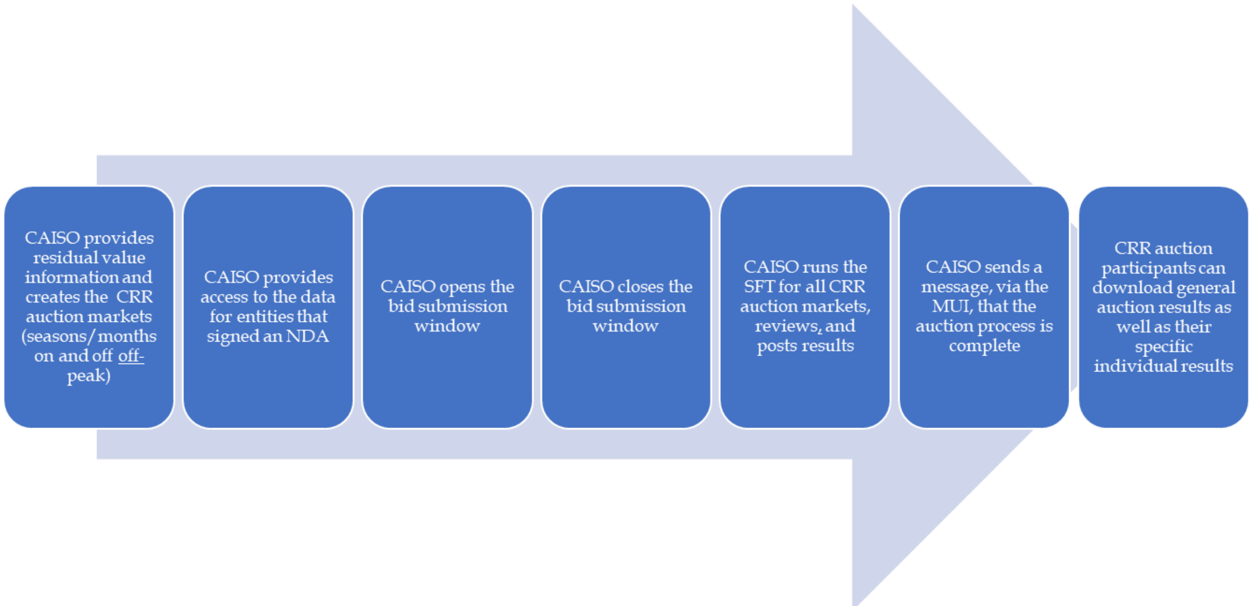
14.1.7 CRR auction mechanisms

The CRR auction mechanism in CAISO is a bid-based market that produces clearing prices, while the allocation process only awards MW amounts with no dollar value. When the auction clears, the system calculates a clearing price for every Aggregated Pricing Node ("APnode"), which is published publicly. Auction participants can submit buy offers and/or sell offers for any CRRs that they acquired in a prior allocation process or auction.

The annual and monthly auctions are open to any registered market participant (subject to the creditworthiness requirements under the ISO Tariff).[302] So financial participants are not precluded from acquiring CRRs. While the buy offers must include a descending price curve, the sell offers must include an ascending price curve. Figure 107 below demonstrates the steps taken by CAISO during the auction.

[302] CAISO. "Business Practice Manual for Congestion Revenue Rights." Version 27. Last Revised: March 27, 2020.

Figure 107. CAISO auction process – annual and monthly



Note: The residual value information covers the scheduling point/transmission interfaces after Tier 2 allocation. The Data for entities that signed the NDA includes the CRR FNM and associated commercial data for the auction in play.

Source: CAISO, "Business Practice Manual for CRR. v 27." March 27, 2020. p. 16.

As discussed in Section 14.1.3, Track 1A of CAISO's reforms included limiting the paths available through the CRR auction to only delivery paths (comprised of source and sink pairs associated with supply delivery to load). Bids to purchase CRRs in the CRR auction must specify the associated season/month and TOU period, and the CRR Source and CRR Sink. All buy bids must follow a piecewise linear monotonically decreasing[303] bid curve in quantities (up to 20 MW-price points, denominated in thousandths of MW) and prices ($/MW), where any bid point is allowed if the first MW quantity is zero.[304] Each price point on the bid curve represents the maximum price the bidders are willing to pay for the next increments of CRR quantity. Bids can be positive (what the participant is willing to pay to buy) or negative (what the participant is willing to be paid to buy).

[303] A bid structure following a piecewise linear monotonically decreasing curve is composed of straight-line segments of consistently decreasing and never increasing values. For example: 0-50 MW at $20/MW, 50-100 MW at $10/MW, 100-200 MW at $5/MW, etc. For a monotonically increasing piecewise linear curve, it would be the opposite (price increase as quantity increase).

[304] Version 22 - California ISO. https://bpmcm.caiso.com/BPM%20Document%20Library/Congestion%20Revenue%20Rights/Congestion%20Revenue%20Rights%20BPM%20Version%2022_clean.doc

CRR holders have the option to either sell the active CRR in the auction as an offer or sell it in the Secondary Registration System managed by CAISO.[305]

14.1.8 Size of the CRR auctions

According to the CAISO's Tariff Revisions filing with the FERC, "CAISO states that with an efficient CRR auction, prices of auctioned CRRs are expected to generally reflect market participants' expectations of congestion exposure in the day-ahead market, as adjusted for the risk premium, time value of money, and hedge value. However, CAISO notes that this has not been the case in recent years as the discount in auction prices relative to CRR payouts far exceeds any reasonable risk premium and the time value of money adjustment."[306]

According to CAISO, the majority of CRRs sold in auctions tend to be generator––generator CRRs, which are sold at a deep discount compared to the expected return.[307] Between 2009 and 2018, CAISO reported losses of over $800 million for transmission ratepayers (i.e., load).[308] During this time, $0.50 in auction revenue was collected for every $1 in auctioned CRRs. To reverse the trend of these systematic losses, in January 2019, CAISO implemented reforms for the CRR market, including:

- increasing the number of constraints enforced by default in the CRR models;[309]
- limiting allowable CRR source and sink pairs to 'delivery path' combinations;[310] and
- reducing the CRR payments based on the effectiveness of constraints.[311]

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[305] CAISO provides the Secondary Registration System ("SRS") for any registered Candidate CRR Holders and CRR Holders to facilitate and track the CRR bilateral transactions that occur between CRR Holders. The SRS is a subsystem within the CRR system. Source: CAISO. "Business Practice Manual for Congestion Revenue Rights." Version 27. Last Revised: March 27, 2020.

[306] Federal Energy Regulatory Commission. Docket No. ER19-26-000. Washington DC. 2018.

[307] CAISO. "CRR Revenue Adequacy, Auction Values, and Settlement Rules." CAISO MSC. April 04, 2018., p. 19.

[308] CAISO. "Problems in the performance and design of the congestion revenue right auction." November 27, 2017., p. 5.

[309] CAISO. "Congestion Revenue Rights Auction Efficiency, Track 1B Straw Proposal," 2018. April 19, 2018., p. 8.

[310] CAISO. "Congestion Revenue Rights Auction Efficiency, Track 1A Draft Final Proposal Addendum, 2018." March 08, 2018., p. 30.

[311] CAISO. "Congestion Revenue Rights Auction Efficiency, Track 1B Draft Final Proposal Second Addendum, 2018." June 11, 2018., p. 29.

In line with the discussion above, in 2019, CAISO's net CRR auction revenues declined to $63 million from an average of $83 million in 2017 and 2018. This net auction revenue is received by the ratepayers, distributed by the load share.[312]

Between 2018 and 2019, each category of market participants experienced a decline in net revenues. While the financial entities experienced the most significant absolute decrease in net revenues, the physical generator and load lost most in relative terms. Further, the slightly negative revenue for physical generator and load reflects that the hedges did not compensate for the congestion charges paid. Figure 108 summarizes the CRR market's performance, broken down between various market participants in the last two years.

Figure 108. Performance of CRR market participants in CAISO

CRR Market Participant	DMM categorization	Net Revenue – 2018 (Auctioned Rights)	Net Revenue – 2019 (Auctioned Rights)	Summary – 2019
Financial Entities	Own no physical energy and participate in convergence bidding and CRR markets as financial entities	$91 million	$23 million	Paid $0.63 in auction revenues per dollar of CRR payments received
Marketers	On the interties and those whose portfolios are not primarily focused on physical or financial participation in the ISO	$24 million	$3 million	Paid $0.92 in auction revenues per dollar of CRR payments received
Physical Generator	Participate in the ISO as physical generators	$16 million	($3 million)	Paid $1.20 in auction revenues per dollar of CRR payments received
Load	Participate in the ISO as LSEs			

Source: CAISO, "2019 Annual Report on Market Issues and Performance." [313]

[312] CAISO. "2019 Annual Report on Market Issues and Performance." June 2020, p. 226.

[313] CAISO. "2019 Annual Report on Market Issues and Performance." June 24, 2020. pp. 13, 24, 153, 160, 232-234, 289.

14.1.9 Settlement

According to the CRR Training, "SFT is applied to help ensure that the level of CRRs (i.e., the MW quantity or quantities) that are allocated or auctioned do not create entitlements that generate more payout to CRR holders than what is brought into the ISO by congestion revenue in the DAM."[314] The SFT mechanism ensures gross revenue adequacy[315] if the transmission capability used in the SFT matches the one used in the DAM. An imbalance may result in congestion revenues collected to be insufficient to fully fund the CRR settlement awarded by CAISO. The DMM has identified such imbalance to be a key cause for the historical CRR gross revenue inadequacy.[316] The imbalance can be attributed to various factors such as:

- the difference in the constraints modeled by the SFT and the DAM;
- the topology of the transmission grid changes between the time the SFT is performed and by the DAM; and
- frequency of the SFT (monthly peak and off-peak) against the DAM (hourly).[317]

Therefore, DMM proposed the alignment between the CRR Simultaneous Feasibility Test and the market model.

In the past, CAISO used to account for CRR revenue inadequacy through an uplift charge to the LSEs based on the measure demand (i.e., metered demand and exports). In January 2019, this method was changed to a CRR Partial Funding mechanism that pays CRRs a value less than or equal to the amount of congestion charges collected in the DAM. A shortfall in the value of the CRR is pro-rated based on the impact of the CRR on the deficit by constraint. In line with the CRR Auction Efficiency Track 1B discussed in Section 14.1.3, when there is a shortfall in the congestion revenue on a particular constraint (i.e., when Integrated Forward Market congestion charge collected is less than CRR payout), the impacted CRRs are discounted, and the CRR payment is reduced from its nominal value. [318]

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[314] CAISO. "ISO Congestion Revenue Rights (CRR) Training." May 26, 2016., Figure 18, p. 65.

[315] Gross Revenue Adequacy refers to the difference between day-ahead congestion charges collected by CAISO and the CRR settlements that must be paid by CAISO, without considering any revenues realized in the CRR auction.

[316] CAISO. "Allocating CRR Revenue Inadequacy by Constraint to CRR Holders." October 06, 2014.

[317] CAISO. "Contingency Modeling Enhancements CRR Alternatives Discussions." February 19, 2016. p. 3

[318] CAISO. "Business Practice Manual for CRRs, Partial Funding." Calculation Attachment J. V24. March 6, 2019. P. 173.

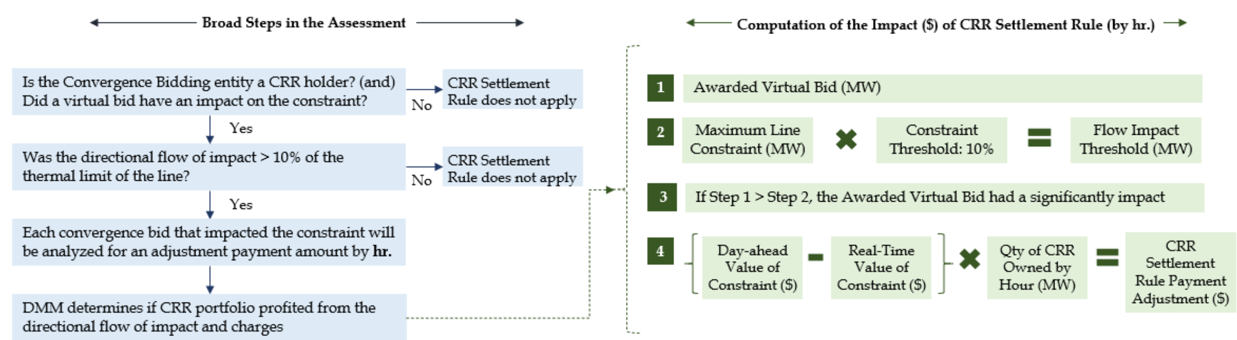
Positive auction revenues are credited to the CRR balancing fund since the CRR holders are paying CAISO to acquire CRRs, and vice versa. CAISO computes surplus/shortfall on the CRR payouts on an hourly basis. The SFT results are tracked by the CRR Balancing Account.[319]

14.1.10 CRR settlement rule

CRR Settlement rule aims to limit CRR payments to entities if they increased the value of the CRRs they hold using virtual bids. CAISO implemented convergence bidding or virtual bidding in its energy markets in February 2011.[320]

The scope of the CRR Settlement Rule includes CRR holders that participate in convergence bidding. If the convergence bid impacts a constraint and the directional flow of impact is larger than 10% of the line's thermal limit, the CRR settlement rule is applied. The flow chart in Figure 109 explains the mechanism of the CRR Settlement Rule.

Figure 109. Mechanism of the CRR settlement rule in CAISO



Source: CRR Settlement Rule. "Congestion Revenue Rights Settlement Rule ADDENDUM, 2017." March 09, 2017

Compared to PJM's forfeiture rule, CAISO's CRR Settlement Rule or Claw Back Rule triggers when the flow impact of a CRR's holder's entire virtual award portfolio exceeds 10% of the flow limit for each transmission constraint. When this happens, the CAISO adjusts the CRR revenues. The 10% threshold is the same as PJM. However, unlike PJM, CAISO does not have the $0.01 threshold. In addition, CAISO provides its participants with information such as:

- DFAX for each constraint that binds in the day-ahead and real-time market within three calendar days of the market day; and

[319] CAISO. "ISO Congestion Revenue Rights (CRR) Training." May 26, 2016., Figure 18, pp. 65-68.

[320] CAISO. "Congestion Revenue Rights Settlement Rule ADDENDUM," 2017. March 09, 2017., pp. 4-5.

- transmission limits for all constraints in the day-ahead and real-time markets.[321]

These are important information for the participants to monitor and modify their behavior so that CRR Settlement Rule does not unduly constrain market activity.[322]

14.2 ERCOT

ERCOT operates the transmission grid and administers the wholesale electricity market in most of Texas. The ERCOT controlled area covers 75% of the state's total area[323] and provides energy to 90% of its total load.[324] ERCOT has a congestion revenue rights product, which is equivalent to the FTR in that it is PTP based. ERCOT does not have ARRs or an ARR allocation process. LSEs are directly allocated a share of the CRR auction revenues. Similarly, the wholesale transmission service in ERCOT is based on a postage-stamp methodology[325] in which the load pays for the transmission expansion.

LEI included ERCOT as one of the case studies because it allocates congestion rights to load, which differs starkly from that currently employed at PJM. On the other hand, there are many similarities between FTRs in PJM and CRRs in ERCOT, including the PTP nature of CRRs and FTRs, annual or long-term[326] FTR/CRR product (6-month term), and treatment of LSEs vis-à-vis the CRRs. Until 2018, ERCOT was the second-largest FTR market both in terms of auction revenues and the Day-ahead congestion charges in the US.

14.2.1 Overview of the ERCOT market

Unlike other ISOs, which are subject to FERC oversight, ERCOT operates under the regulation of the Public Utility Commission of Texas ("PUCT") as ERCOT is not synchronously connected with the two major US interstate grid systems, the Eastern and the Western Interconnections. Potomac Economics is the equivalent of IMM in ERCOT, employed by the PUCT. ERCOT operates a nodal

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[321] XO Energy LLC. "Compliant of XO Energy vs. PJM Interconnection," April 8, 2020. p. 50.

[322] Ibid.

[323] Other parts of Texas are served by utilities belonging to the Southwest Power Pool, the Southeastern Electric Reliability Council, and the Western Electricity Coordinating Council.

[324] ERCOT Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM, 2019." May 14, 2020., p. 9.

[325] Note: under this, socialization of costs was an important incentive to the companies that ultimately built the Competitive Renewable Energy Zones ("CREZ") projects. The fact that the CREZ costs would be reflected in rates made cost recovery more certain, which in turn supported effective financing of the projects.

[326] Annual auctions and long-term auctions are considered same in this analysis.

real-time balancing market and a nodal DAM and an ancillary services co-optimized market.[327] Figure 110 illustrates the ERCOT market ecosystem.

ERCOT has an energy-only market design (no capacity market). ERCOT has a voluntary (physically non-binding) but financially binding DAM. Since 2013, ERCOT has set an offer cap at $9,000/MWh[328] that is linked to the value of lost load, which is used to achieve adequate scarcity pricing (and therefore liquidity) in an energy-only market design. In comparison, PJM has an energy plus capacity market design, and is both a physically binding and financially binding day-ahead energy market (however, the DAM transactions in PJM will not physically flow unless they are also submitted in the Real-Time Energy Market). As of March 31, 2020, PJM's installed generation capacity of 185,189 MW[329] is almost double the ERCOT market size (~102,000 MW[330] installed capacity). The global market for corporate renewable energy deals in 2019 was around 19.5 GW. Of this, nearly, 30% of all the energy deals signed were in Texas for about 5.5 GW worth in new contracts[331] with oil and gas producers starting to become active participants. The development of new industrial facilities in the Far West Texas region's coastal areas continues to drive the robust growth in peak electricity demand and congestion. Figure 111 summarizes some of the key statistics describing the ERCOT electricity market.

ERCOT was created as an ISO in 1996. It expanded its offering from a broker of wholesale power to a platform in 2002 that enabled Texas electric utility industry to transition to retail competition. At the time the wholesale market was real-time and zonal in nature. Nodal design was introduced in December 2010,[332] along with a new DAM. ERCOT's market

QSEs are responsible for scheduling, telemetry, and settlements on behalf of LSEs and REs. QSE can participate in the DAM and the Real-Time Market as a power marketer (without representing generation or load)

REs either own and/or control generation resource, load resource, and/or non-modeled generator

327 In January 2019, the PUCT gave ERCOT direction to implement Real-Time Co-optimization ("RTC") to reduce overall energy and AS costs by allowing resources to procure energy and AS simultaneously in the Real-Time Market. RTC should be implemented by mid-2024. See "Board Education on Real-Time Co-optimization", ERCOT, October 8, 2019.

328 The Public Utility Commission of Texas. "Estimating the Economically Optimal Reserve Margin in ERCOT." January 31, 2014. p. 1.

329 Potomac Economics. Monitoring Analytics, LLC. *Q1 State of the Market Report, 2020.* May 14, 2020., Table 1-1, p. 3.

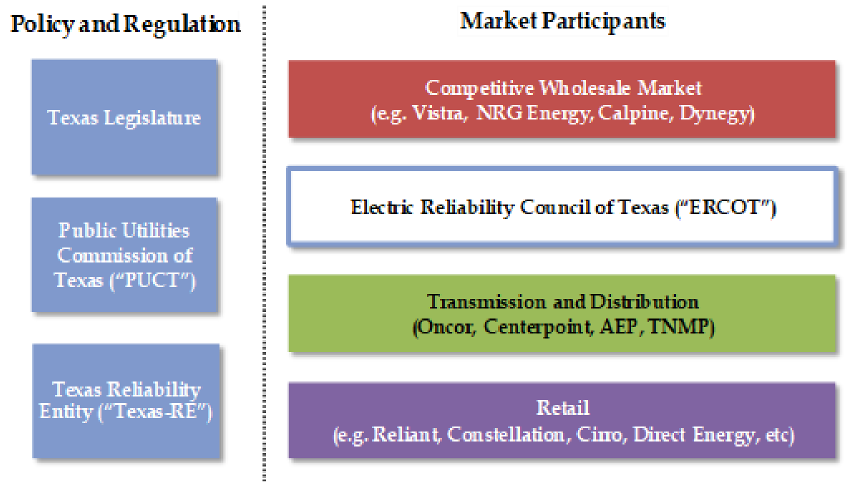
330 "Resource Adequacy Challenges in Texas, 2020" Environmental Defense Fund. Web. May 2020. < https://www.edf.org/sites/default/files/documents/EDF-ERCOT-Report.pdf >

331 "Texas Is the Center of the Global Corporate Renewable Energy Market." *Greentech Media*. January 28, 2020. <https://www.greentechmedia.com/articles/read/texas-is-the-center-of-the-global-corporate-renewable-energy-market>

332 "Nodal Systems." *ERCOT Launches Improved Wholesale Market Design. News Release*. Web. December 01, 2010. <http://www.ercot.com/news/releases/show/349>

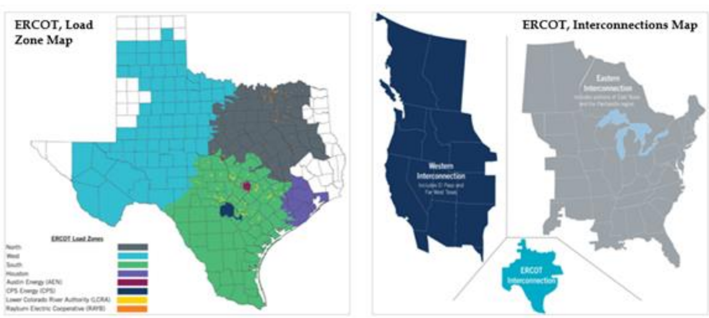
ecosystem includes Qualified Scheduling Entities ("QSEs"), LSEs, Transmission and/or Distribution Service Providers, and Resource Entities ("REs").

Figure 110. Electricity Market Structure in Texas

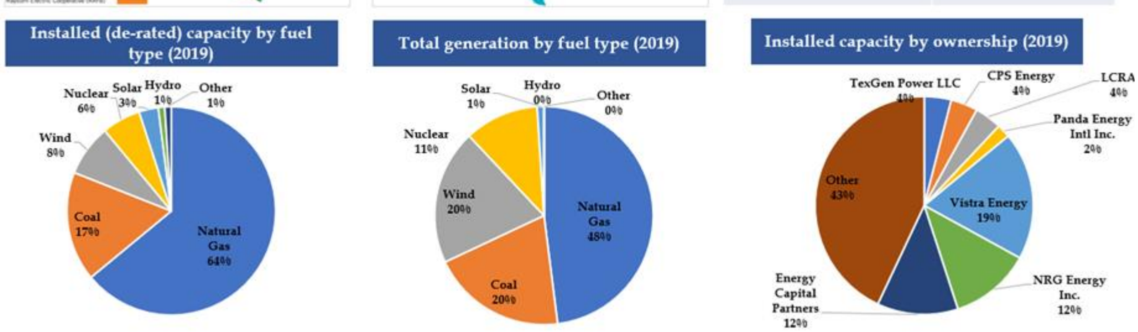


Source: LEI

Figure 111. ERCOT: Snapshot, 2019



Key facts (2019)	
Installed (de-rated) capacity	81,316 MW
Peak demand	74,820 MW
Generation	383,429 GWh
Transmission lines	46,500 miles
People served	26 million
Area served	75% of land area



Sources: ERCOT; commercial third-party database.

Note: Non-coastal wind de-rated to 16% (except Panhandle region, 29%) in line with ERCOT planning practices; coastal wind de-rated to 63%; solar de-rated to 76%.

While only a small share of the power produced is transacted in the real-time energy market,[333] real-time energy prices aid in setting expectations for prices in the DAM and bilateral forward markets. The DAM allows participants to make financially binding (but not physically binding) forward purchases and sales of power for delivery in real-time, with no operational obligations. Furthermore, ERCOT's Nodal Market operations' market components include the CRR Auction, DAM, Reliability Unit Commitment,[334] and Real-Time Operations.

ERCOT maintains a single property right system where load is directly allocated auction revenues from the sale of CRRs. Further, ERCOT uses a socialized transmission rate approach as compared to PJM's zonal transmission rate methodology.

14.2.2 Brief history of the ERCOT's CRR market

With the implementation of the Nodal Market Design in December 2010, ERCOT introduced the CRR program that replaced the decade-old Zonal Transmission Congestion Rights[335] program that operated within the zonal real-time market design that existed before 2010 in ERCOT.

As described in CRR—MUI User Handbook, the main purposes of the CRR program were "to support a liquid energy market by providing tradable financial instruments for the hedging of transmission congestion charges, to allow market participants to eliminate or greatly reduce the cost uncertainties resulting from transmission congestion charges, and to encourage competitive energy trading, where the costs of congestion might otherwise be an impediment."[336] ERCOT's goals explicitly acknowledge that there are two purposes to CRRs, similar to the findings LEI developed for PJM's ARR/FTR mechanism under Section 3).

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[333] ERCOT Market Monitoring Unit. Monitoring Analytics, LLC. "State of the Market Report for PJM, 2018." June 2019. p. 8.

[334] ERCOT continually assesses the adequacy of market participants' resource commitment decisions using a reliability unit commitment (RUC) process, which executes both on a day-ahead and hour-ahead basis. RUCs might be required to meet the projected system-wide demand and make a specific generator available resolve a transmission constraint. See "Transmission Congestion Rights." *ERCOT*. Web. November 02, 2020. <http://www.ercot.com/services/programs/tcr>

[335] The TCRs were introduced in ERCOT in February 2002 when ERCOT was still under a zonal pricing. ERCOT implemented a direct-assigned allocation process for settlement of zonal congestion costs. During that time, the ERCOT market was a bilateral market and did not have a spot market. A small number of commercially significant transmission constraints (CSCs) were identified yearly. The TCRs worked as a financial hedge against interzonal congestion costs to receive payment at the shadow price of energy for the congestion value of the CSCs. See "Reliability Unit Commitment." *ERCOT*. Web. November 12, 2020. < https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf>

[336] ERCOT. "CRR - MUI User Handbook (Document Version: 2.10)," September 10, 2011., p. 6.

In addition, ERCOT introduced the semi-annual sequence of four consecutive six-month CRR Auctions selling CRRs up to two years in the future in May 2012, as a part of the CRR auction structure enhancements.[337] Factors supporting the introduction of this feature included:

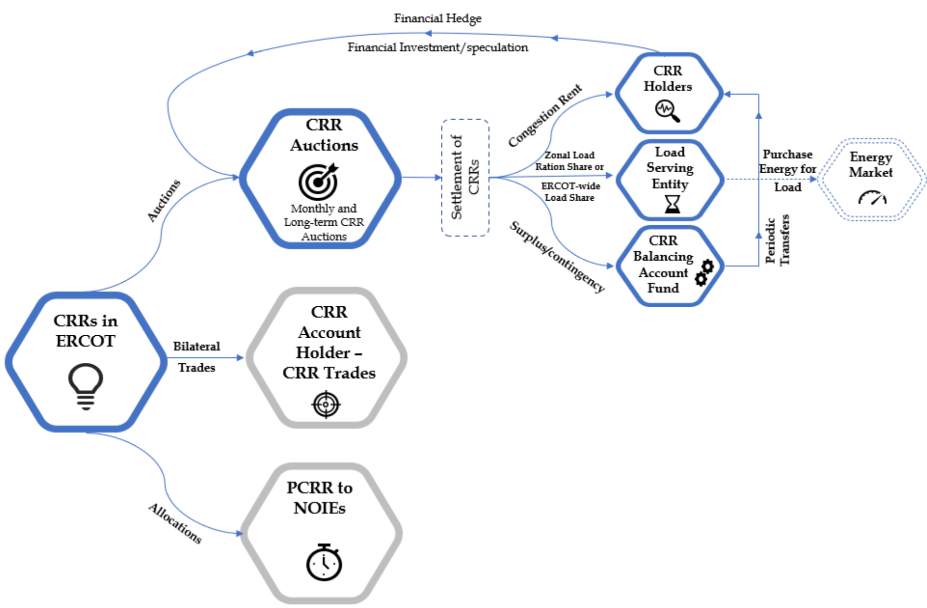
- greater liquidity due to higher frequency for any given date range of CRR products to be sold; and
- frequent market valuation and price discovery of CRR products help market participants better understand the holdings' evolving valuation and risk.

Moreover, ERCOT established the rolling Balancing Account Fund[338] in June 2013 to streamline the auction settlement process.

14.2.3 FTR mechanisms

The flow of funds process associated with the CRR trading commences with the acquisition of CRRs, followed by settling of the CRR trade and collecting/distributing of CRR auction revenues to the beneficiaries, namely load, as shown in Figure 112. Each item will be discussed in the succeeding sub-sections.

Figure 112. Flows of funds related to CRRs in ERCOT



[337] ERCOT. "CRR Auction Structure Enhancements." NPRR463. May 2012.

[338] ERCOT. "CRR Balancing Account Fund." NPRR580. June 2013.

Sources: LEI analysis

“Network Operating Model.” Module 1: ERCOT NODAL 101. ERCOT. Web. 2017. <http://www.ercot.com/content/wcm/training_courses/109518/Nodal_101.pdf>

“CRR Balancing Account.” Module 4: CRR Balancing Account. ERCOT Web. September 2016. < http://www.ercot.com/content/wcm/training_courses/44/M4___Set301___Bal_Act___Sept2016.pdf >

“Congestion Revenue Rights.” Module 5: Congestion Revenue Rights. ERCOT. Web. September 2016. < http://www.ercot.com/content/wcm/training_courses/109600/TRN101_M5_CRRs_2017.pdf>

“Day-Ahead Market.” Module 6: Day-Ahead Through Real-Time Operations. ERCOT. Web. 2017. < http://www.ercot.com/content/wcm/training_courses/109600/TRN101_M6_DAM_RT_2017.pdf >

14.2.3.1 CRR product

CRR market participants[339] include QSEs, LSEs, REs, and CRR account holders. While CRR can be bought and sold by various market participants, settlements are only with QSEs-[340]. CRRs are based on a PTP construct. CRRs are designed by a specific point of injection (the source), and a specific point of withdrawal (sink), and both source and sink must be settlement points. The payment/charge to the CRR accountholder is based on the difference between the settlement point prices at the sink and source. The ERCOT market has two types of CRRs:

- **PTP options**, which entitle the holder to receive compensation equal to the absolute energy price difference between sink and source settlement points; and

- **PTP obligations** require that the holder receive (or pay) all differences, positive (or negative) in energy price between the sink and source settlement points; these can result in either a payment or a charge for the holder.

These CRRs are financial transactions settled against the energy prices in the DAM. While generation hedging comprises most of the volume of the PTP obligations purchased, some PTP obligations are also bought by financial parties and physical parties (i.e., those with actual real-time load), and generators representing the generation hedge and comprised the bulk of the PTP obligations volume purchased. The balance of PTP obligations is not directly linked to a physical position and is purchased largely to arbitrage anticipated price differences between two locations or hedge trading activities outside the organized market.

[339] CRR market participants include QSEs, LSEs, REs, and CRR account holders.

[340] ERCOT. “ERCOT QSE and CRR AH Qualification Guide, 2006.” July 2014., V4, p. 1. “Module 1 – Fundamentals of CRRs (CRR Trades)” Congestion Revenue Rights – Web-based Training. ERCOT. Web. Accessed on October 22, 2020. <http://www.ercot.com/services/training/course/115061#schedule>

These options and obligations are offered on any combination of over 585 settlement points[341] or any ("time of use") TOU block.[342] These points comprise resource nodes (including generation nodes), load zones, and hubs. While PJM has fewer FTR classes than ERCOT, it has more biddable paths, which means more decision points for participants. ERCOT's over 500 settlement points for any TOU, current CRR ownership represents around 70% as options and 30% as obligations.[343]

If the congestion causes a price spread between the resource node and the load zone, the QSE is exposed to real-time congestion hedging. PTP obligations purchased in the DAM provide a hedge against congestion costs in real-time. DAM PTP obligations can be purchased:

- as a financial hedge (to achieve price certainty, instead of locking in congestion cost at CRR auction price, which locks in the cost of real-time congestion at DAM prices); or
- as a financial investment (i.e., on a speculative basis, when real-time value > purchase price).

Irrespective of the purchase described above, the acquisition and settlement of the instruments are the same - they are initially purchased at the DAM price spread between the source and sink settlement points, and once owned, they are settled on the real-time price spread.[344]

ERCOT's transmission system capacity is determined from the Network Operations Model, which reflects characteristics of the ERCOT Transmission System – topology, equipment ratings, other operational limits. Similarly, CRR's Network Model[345] is derived from the Network Operations Model and represents each month's transmission capacity. A CRR Network Model[346] reflects transmission facilities expected to be in-service for the specified month, significant outages, dynamic ratings, monitored elements, contingencies, and settlement points. The CRR Network Model serves as an input for the CRR auction process and CRR allocation for ("Non-opt in Entity") NOIEs.[347] ERCOT posts the models on the MIS prior to each auction, allowing CRR

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[341] These points comprise resource nodes (including generation nodes), load zones, and hubs.

[342] ERCOT. "CRR Market Overview." PJM ARR/FTR Market Task Force, 2020. May 25, 2020., p. 4.

[343] ERCOT. "ERCOT CRR Market Overview." March 25, 2020., p. 5.

[344] ERCOT." ERCOT Market Education: Congestion Revenue Rights." May 2020., pp. 22-29.

[345] ERCOT. "ERCOT Market Education: Transmission 101, 2013." March 2013., p. 64.

[346] Outages included in the CRR Network Model shall be posted on the Market Information System (MIS) Secure Area consistent with model posting requirements by ERCOT with accompanying cause and duration information, as indicated in the Outage Scheduler. See "CRR Network Model." *ERCOT Nodal Protocol*. March 01, 2019. p. 7-14.

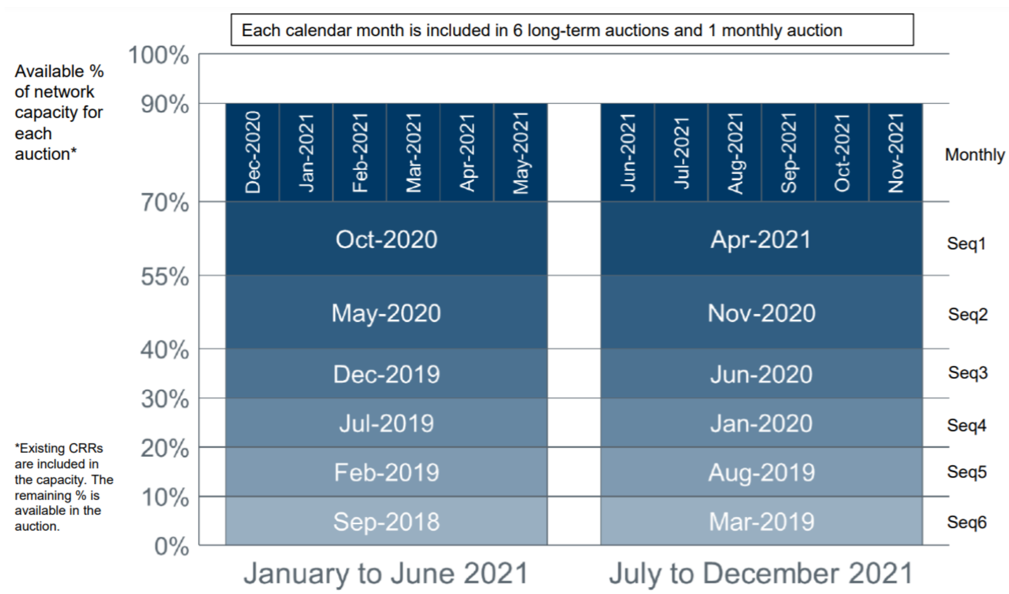
[347] NOIEs are pre-allocated some CRRs at a discount. consist of municipally owned utilities (such as Austin Energy and CPS Energy), electric cooperatives (such as South Texas Electric Cooperative and Brazos Electric Power Cooperative Inc.), and River Authorities (such as LCRA). Typically, NOIEs either own a generation resource, or have a long-term contractual agreement for annual capacity and energy from specific generation resources

account holders to download the model and determine their bid/offer strategies in an auction. The model is posted no later than 10-business days before the monthly auction and no later than 20-business days before the annual auction sequence begins.[348]

14.2.3.2 FTR auction mechanism[349]

The auctions at ERCOT take place only in monthly and annual (also considered long-term) formats.[350] ERCOT does not have an LT auction like PJM where the FTR (or CRRs) can be bought three years in advance. ERCOT's CRR auctions vary based on the frequency and products offered. Figure 113 shows the timing of these auctions within a 12-month cycle. After each CRR auction window closes, the list of participating CRR account holders is ascertained.

Figure 113. Illustrative CRR Auction Timing in ERCOT



Source: ERCOT. "CRR Market Overview. PJM ARR/FTR Market Task Force, 2020." March 25, 2020., p. 12

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or have a long-term allocation from the Federal Government for annual capacity and energy produced at a federally-owned hydroelectric generation resource.

[348] "Module 2 – CRR Auction & Allocation Process (CRR Trades)" Congestion Revenue Rights – Web-based Training. ERCOT. Web. Accessed on October 22, 2020. <http://www.ercot.com/services/training/course/115061#schedule>

[349] Source of this Section is from ERCOT. *Module 5: Congestion Revenue Rights, 2017.* September 2017; "Module 2 – CRR Auction & Allocation Process (CRR Trades)" Congestion Revenue Rights – Web-based Training. ERCOT. Web. Accessed on October 22, 2020. <http://www.ercot.com/services/training/course/115061#schedule

[350] ERCOT. *CRR Market Overview. PJM ARR/FTR Market Task Force, 2020.* March 25, 2020., p. 13.. The CRR Activity Calendar lists the dates for all CRR auctions for current calendar year alongside those in the following 2-years

The **monthly CRR auctions**[351] are conducted once every calendar month. As a part of the monthly auctions, ERCOT offers Participating CRR Account Holders with PTP obligation and PTP options for the month immediately following the month during which the CRR auction closes. As shown in Figure 113, ERCOT puts up 90% of the monthly capacity to be consumed by CRRs at each monthly auction.

The **Annual CRR auctions**[352] are conducted once every calendar month, across six sequences/auctions. The sequences span a term of six consecutive calendar months (either January through June or July through December). As shown in Figure 113, each month, the CRR annual auctions sequence: 70%, 55%, 40%, 30%, 20%, or 10% for the first, second, third, fourth, fifth, and sixth six-month windows sold. Therefore, the annual CRR auctions offer CRRs for the next three years in six-month blocks. ERCOT interchangeably refers to annual CRR auctions as annual auctions.[353]

Figure 114. CRR Auction - Timeline of Information Posting in ERCOT

CRR Auction Type	Type of information posted	Timeline
Network model (on which the CRR auction will be executed)	Monthly CRR auction	10 days ahead of the transaction window
	Long-term CRR auctions	20 business days ahead of the transaction window
Market notice	Monthly CRR auction	10 days ahead of the transaction window
	Long-term CRR auctions	20 business days ahead of the transaction window

Source: ERCOT Nodal Protocols. <http://www.ercot.com/content/wcm/current_guides/53528/07-090120_Nodal.doc>

351 Each monthly auction must specify the TOU block (such as, peak weekday (5x16), peak weekend (2x16), off-peak (7x8), and 24-hour).

352 See footnote 351.

353 Market information section of CRR captures the annual CRR auction details under 'Annual CRR Auction Notice, 'Annual Auction Results', and Annual Path Specific Adders' < http://www.ercot.com/mktinfo/crr>. Further, ERCOT Nodal Protocols, published in September 2020 (p. 7-16), discuss the CRR Auction Capacity for monthly and annual auctions < http://www.ercot.com/content/wcm/current_guides/53528/07-090120_Nodal.doc>. Lastly, the CRR MUI Handbook (v 4.2), published in May 2019, confirms CRR Auction Timelines limited to annual auctions and monthly CRR auctions.

As there is no concept of ARRs in ERCOT, LSEs cannot acquire CRRs "for free." Bidders in the CRR auctions must submit a minimum reservation price[354] and quantity. A minimum for the PTP options is set at $0.01/MW per hour and is reviewed by the ERCOT Technical Advisory Committee annually. A PTP option can still clear at $0, but in these cases, the awarded CRR holders will pay auction fees as the difference between the clearing price and the minimum price, resulting in a total price of $0.01/MW per hour. In addition, the CRR offer represents the willingness to sell CRRs at a monthly or annual auction.

Like other jurisdictions, ERCOT conducts an SFT to confirm if the transmission system can support the awarded set of CRRs during normal system conditions.[355] [356] The process uses a DC power-flow model[357] for simplicity. After the auctions are complete, the SFT is used prior to each DAM to ensure that each set of CRRs and PCRRs is still feasible for that operating day. CRR Auction Offer Award Disclosure[358] was introduced in July 2011. To achieve consistency with the disclosure of results of the CRR Auction Bid Awards, ERCOT introduced the functionality to post the Offer Awards on the Market Information System public area. This feature was introduced to provide greater transparency for market participants about CRR auction pricing outcomes and be comparable with other ISO's in terms of their reporting results.

14.2.4 Size of ERCOT's CRR market

CRR auction revenues in ERCOT reached $612 million in 2019, growing at a CAGR of 15.3% for the past five years. This trend is captured in Figure 115.

The increase in the auction revenues corresponds with the trend in congestion costs. However, as seen in the chart above, the ratio between auction revenues and the day-ahead congestion rent has fluctuated – between 2015 and 2019, this ratio has been 1.53, 1.28, 1.08, 0.84, and 1.72 respectively. As compared to PJM, with the exception of 2018, this ratio has consistently been above 1.0.

Day-Ahead Congestion charge collected by ERCOT in 2015 totaled $1,081 million and rose to $8,197 million in 2019, highlighting a very congested market. The Day-Ahead Congestion charge or the amount available for payment to the holder of CRRs increased much more than auction prices for CRR products in the annual auction. This differential trend is captured in Figure 116

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354 The reservation price (dollars per CRR (i.e., dollars per MW per hour) is indicated in the CRR Auction Offer by the participating CRR holder.

355 ERCOT Nodal Protocols. <http://www.ercot.com/content/wcm/current_guides/53528/07-090120_Nodal.doc>

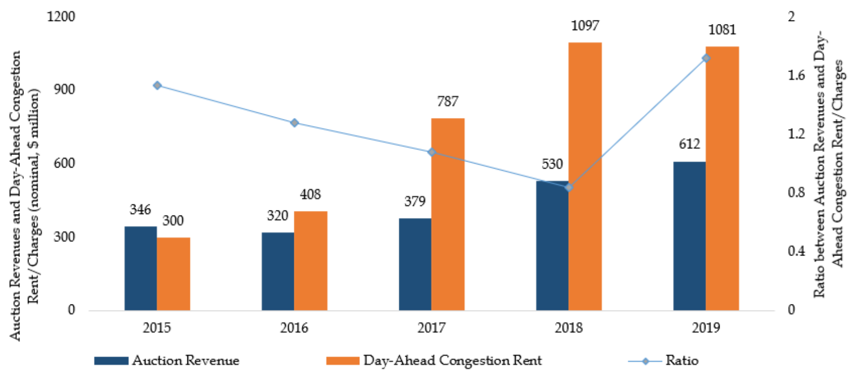
356 The SFT is also used to validate the requested allocation of PCRRs before the monthly and annual auctions.

357 ERCOT." Nodal Protocols: Section 7: Congestion Revenue Rights." July 01, 2019., V2.1, p. 30.

358 ERCOT. "CRR Auction Offer Award Disclosure." NPRR395. July 2011.

shows the comparative contribution of the auction revenues – monthly auction and annual auctions across various zones.

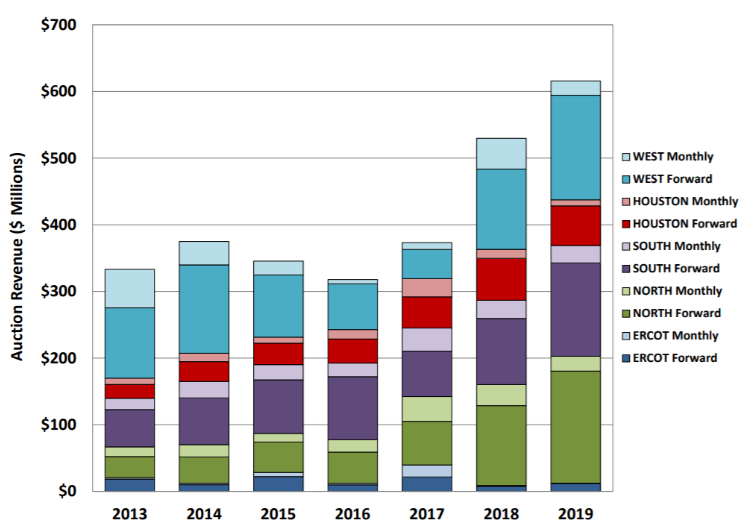
Figure 115. ERCOT CRR auction revenue vs. day-ahead congestion charges (nominal, $ millions)



Source: State of Market Report, ERCOT (2015-2019), LEI Analysis.

Note: ERCOT's Day-ahead congestion charge is calculated as the sum of the total of payments to all QSEs for cleared DA energy offers, a total of charges to all QSEs for cleared DA Energy Bids, total of charges or payments to all QSEs for PTP Obligation bids cleared in the DA Market, and a total of charges to all QSEs for PTP Obligation with Links to an Option bids cleared in the DA Market.

Figure 116. Trend in ERCOT CRR auction revenues: By zone and type of auction (nominal $ millions)



Note: Potomac Economics reports the monthly auction revenues under 'monthly' and six-month auctions or annual auctions as 'forwards'; zones are based on binding constraint locations; ERCOT category includes revenues associated with constraints with source and sink in different zones.

Source: ERCOT. 2019 State of Market Report.

As observed in Figure 116, since 2016, overall CRR revenues have increased steadily across zones, and monthly auction revenues have contracted. Changes in the 6-month auction format in terms of greater transmission capacity offered ahead of the monthly auctions contributed to the decline in monthly auction revenues.

14.2.4.1 CRR settlement[359]

The CRR settlements process consists of four sequential elements: CRR Auction Settlement process, CRRs payments in the DAM and Deration, CRR Balancing Account, and CRR Balancing Fund. The CRR Balancing Account's positive balance is distributed amongst the CRR holders, and the positive balance of the CRR Balancing Fund is distributed amongst the QSEs. These are discussed below.

14.2.4.1.1 CRR auction settlement[360]

At the end of each auction, ERCOT invoices each CRR account holder for bids and offers awarded. The net proceeds (i.e., the difference between the charges for each awarded bid and payment for each CRR offer) from a CRR auction flow to the load. Each month, CRR auction revenues are paid out to QSEs representing the load based on their load ratio share. Specifically, auction revenues from intra-zonal (i.e., CRRs that source and sink in the same congestion management zone) CRRs are distributed by zonal load ratio share. The revenues from those CRRs would be paid out to QSEs based on their share of the load in that zone during the monthly peak interval.

Similarly, auction revenues from inter-zonal (i.e., CRRs that source and sink in different congestion management zones) CRRs are distributed based on ERCOT-wide load ratio share.[361]

ERCOT has a single transmission tariff, which all load contributes to pro-rata. The transmission tariff design and the allocation of auction revenues are internally consistent in ERCOT, supporting arguments of equity. However, given that PJM has zonal transmission tariffs, the allocation approach under ERCOT's single rights system would not fit as well in the PJM context. Moreover, eliminating the ARRs from PJM's design would harm some load that has preferred self-schedule ARRs in the FTR auctions. CRRs payments in the DAM and Deration.[362]

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[359] Source for this section is from "Locational Marginal Prices" *ERCOT Market Education – Congestion Revenue Rights. ERCOT*. Web. June 2019. <http://www.ercot.com/content/wcm/training_courses/109553/2019_06_CRR.pdf>

[360] "Module – CRR Settlements" *Congestion Revenue Rights – Web-based Training. ERCOT*. Web. Accessed on October 22, 2020. <http://www.ercot.com/services/training/course/115061#schedule>

[361] ERCOT. *ERCOT Market Education: Congestion Revenue Rights.* May 2020., p. 19.

[362] "Module – CRR Settlements" *Congestion Revenue Rights – Web-based Training. ERCOT*. Web. Accessed on October 22, 2020. <http://www.ercot.com/services/training/course/115061#schedule>

ERCOT collects the congestion charge[363] in the DAM. These funds flow into the congestion charge bucket through charges from cleared DAM energy bids and charges from cleared DAM PTP obligation bids on an hourly basis.

CRR payments might be derated if transmission capacity on the network is oversold (under present conditions, there are more MWs of CRR owned along a particular path than the transmission system can support. For example, because of a transmission outage that had not been considered when ERCOT released the CRRs in the auction). To derate CRRs, ERCOT uses a day-ahead network model, which is created daily and reflects the forecasted transmission system for the next day, updated with scheduled outages and forecasted system conditions. Next, a Day-ahead SFT is executed daily and verifies the feasibility of CRRs previously sold in all auctions, based on the operating day's expected conditions. If SFT is feasible, the transmission system is not oversold, and the CRR account holders are entitled to payment. If SFT is infeasible and the transmission system is oversold, then CRRs with resource nodes associated with oversold paths will be subject to a reduced payment – in this case, ERCOT will derate the payment based on the impact the source or sink resource node has on the resulting transmission constraint. Derating CRRs on specific paths means that expected losses associated with underfunding of specific CRR product paths are not socialized, although the costs may still be borne by load if certain paths are more likely to get derated (as bidders in the CRR auctions would price in the risk and therefore impact the CRR auction revenues that would be available for load if underfunding is anticipated).

14.2.4.1.2 CRR Balancing Account and CRR Balancing Fund[364]

- **CRR Balancing Account** captures the excess congestion charge leftover after payout of the CRR accountholder. The final monthly balance is liquidated by first paying the CRR account holders who faced shortfall charges (due to deration) during the month.

- **CRR Balancing Fund[365]** captures the remaining balance from the CRR Balancing Account at the end of the month, to be used for refunding shortfall charges in future months. The fund has a ceiling set at $10 million, and the excess balance (above the ceiling) is distributed amongst the QSEs on a load ratio share basis. If, at the end of the month, the CRR Balancing Account does not have enough funds to pay the CRR account holders that were short paid during the month, ERCOT can access the CRR Balancing Fund to make the payments. However, if the CRR Balancing Fund account is low or empty and does not have enough funds together with the CRR Balancing Account to pay the CRR

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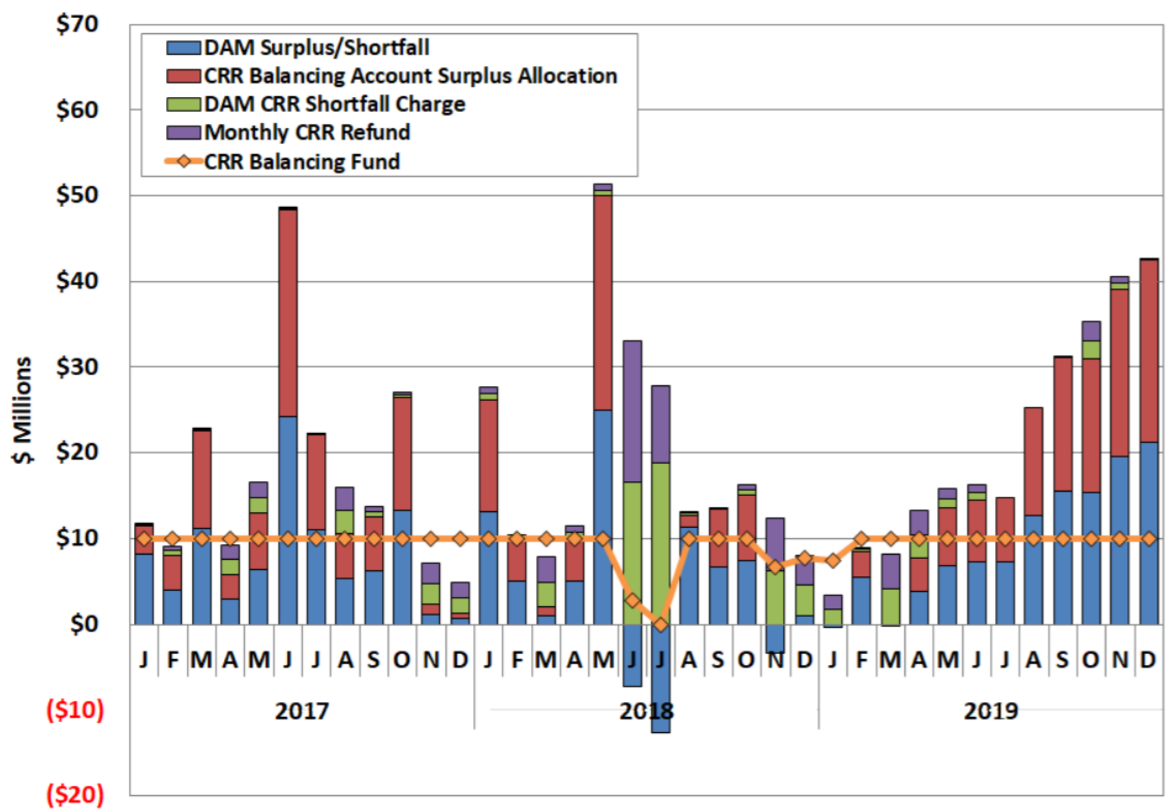
363 Congestion charge = Charges to Load – Payments to Generators < https://wired.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200325/20200325-item-09-ercot-crr-market-overview.ashx>. p. 14.

364 "Module – CRR Settlements" *Congestion Revenue Rights – Web-based Training. ERCOT*. Web. Accessed on October 22, 2020. <http://www.ercot.com/services/training/course/115061#schedule>

365 Note: Also referred to as the CRR Balancing Account Fund

accountholders in full, ERCOT will pay out what is available, and the CRR accountholders may remain short.

Figure 117. Total accumulated and monthly changes to the rolling CRR Balancing Account



Source: ERCOT. 2019 State of Market Report.

In 2019, CRR holders experienced no shortfalls as the CRR Balancing Fund remained steady at the capped level of $10 million.[366] Further, the 2019 annual day-ahead surplus was nearly $115 million, bigger than $52 million in 2018.[367] The CRR balancing allocation to load was at $113 million in 2019. In July 2018, lack of Day-ahead market surplus and CRR Balancing Fund to fully fund the shortfall charge of CRR owners, the fund was $0.[368] Figure 117 illustrates the Balancing Fund across a 24-operation month timeframe in ERCOT.

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[366] Potomac Economics. Monitoring Analytics, LLC. *State of the Market Report for ERCOT, 2018.* June 2019., Figure 32, p. 69.

[367] Ibid.

[368] Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. Figure 36, p. 61.

14.3 MISO

MISO is an RTO that manages grid reliability and organizes energy markets (spot electricity markets, ancillary services markets, and capacity trades) within the midwestern part of the US. MISO's reliability coordination area covers 15 states, including most of Arkansas, Illinois, Indiana, Iowa, Louisiana, Michigan, Minnesota, North Dakota, and Wisconsin, as well as parts of Kentucky, Mississippi, Missouri, Montana, South Dakota, and Texas. MISO's reliability coordination area also covers a part of Canada's Manitoba province.[369] LEI chose MISO as one of the case studies to be reviewed because it is a multi-state RTO like PJM. In addition, like PJM, it has a dual-system of property rights consisting of ARRs and FTRs.

14.3.1 Overview of the MISO market

MISO, previously known as Midwest ISO, was established in 1998 as an ISO after FERC accepted its organizational plan and initial transmission tariff. Subsequently, in response to FERC Order 2000, MISO became an RTO (FERC docket No. R01-87-000).[370] MISO formally started its centrally organized wholesale market for energy in 2005. Since that time, MISO's footprint has also grown. Currently, MISO's membership includes 52 Transmission Owners ("TO") and 137 Non-Transmission Owners.[371] MISO oversees a transmission system covering 71,800 miles of transmission lines, carrying 177,760 MW of power annually, and serving about 42 million people.[372]

MISO's members are primarily still vertically integrated utilities; only three states within MISO have retail competition, namely, Illinois, Michigan, and Texas (MISO only serves parts of these fully deregulated states). Conversely, PJM has fewer vertically integrated utilities and states with retail choice (for example, Delaware, Illinois, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, and the District of Columbia).[373] In terms of load served, MISO is smaller than PJM. MISO's energy and operating reserves market includes a day-ahead market and a real-time market. MISO also administers a Planning Resource Auction ("PRA")[374] and hosts FTR auctions. The PRA construct is different from PJM's capacity market as it is voluntary and, according to

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[369] Manitoba is a member of MISO but is not part of the wholesale market.

[370] MISO Energy. Timeline of our past 15 years. <http://timeline.misomatters.org/>

[371] MISO Energy. MISO Corporate Information. <https://www.misoenergy.org/about/media-center/corporate-fact-sheet/>

[372] Ibid.

[373] Data on retail competition sourced from the EIA.

[374] The PRA is a voluntary annual capacity auction that allows market participant to meet their residual zonal capacity/resource adequacy requirements for the next planning year.

MISO's own IMM, also not reflective of the "true" market value of capacity.[375] Therefore, a majority of the generation investment is still driven by traditional integrated resource plans and financed by vertically integrated utilities.

MISO has adopted a hybrid cost allocation mechanism that results in a different transmission rate throughout the RTO, depending on a consumer's location. For example, some transmission projects are assigned to specific transmission zones while others are socialized across the entire footprint, as summarized in Figure 118.[376]

Figure 118. MISO regional cost allocation

Project type	Project cost allocation
Baseline Reliability Project	100% assigned to local transmission pricing zones
Market Efficiency Project	100% spread to zone corresponding to expected benefits
Multi-Value Project	100% postage stamp to load
Generation Interconnection Project	Less than 345 kV: 100% paid by requestor. More than 345 kV: 10% postage stamp to load, 90% paid by generator

Sources: MISO. "Cost allocation background." OMS Cost Allocation Principles Committee. October 5, 2020.

Like PJM, MISO's fuel mix is dominated by coal and natural gas, each making up about 34% and 41% of the installed capacity, respectively. The remainder of the MISO generation fleet is split between nuclear, wind, and hydropower. Compared to the previous year, the share of coal in both capacity and energy shrank slightly. Gas is playing an increasingly important role, representing 41% of MISO's total installed capacity in 2019. Gas increased from 19% of net generation in 2011 to 32% in 2019. This change can be attributed to a combination of coal retirements due to economics and more stringent environmental rules, as well as favorable fuel pricing conditions for gas-fired technologies.

375 Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. p. 127.

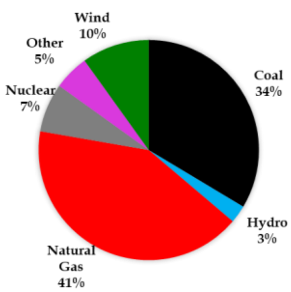
376 For further information regarding other regional project types and interregional (SPP and PJM) cost allocation, see MISO. "Cost allocation background." OMS Cost Allocation Principles Committee. October 5, 2020.

Figure 119. Snapshot of the MISO market

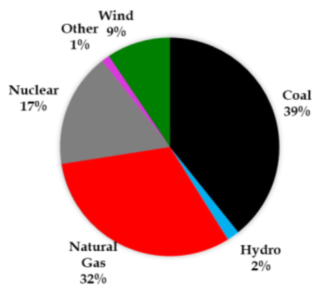
Key facts (2019)	
Installed capacity	197,587 MW
Peak demand	127,000 MW
Generation	608,312 GWh
Transmission lines	Approximately 72,000 miles
People served	Approximately 42 million
Area served	15 U.S. states + the Canadian province of Manitoba

Source: third party data provider (EV), MTEP 20 Report

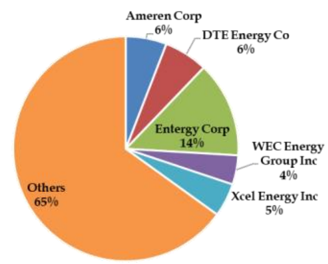
Installed capacity by fuel type (2019)



Total generation by fuel type (2019)



Installed capacity by ownership (2019)

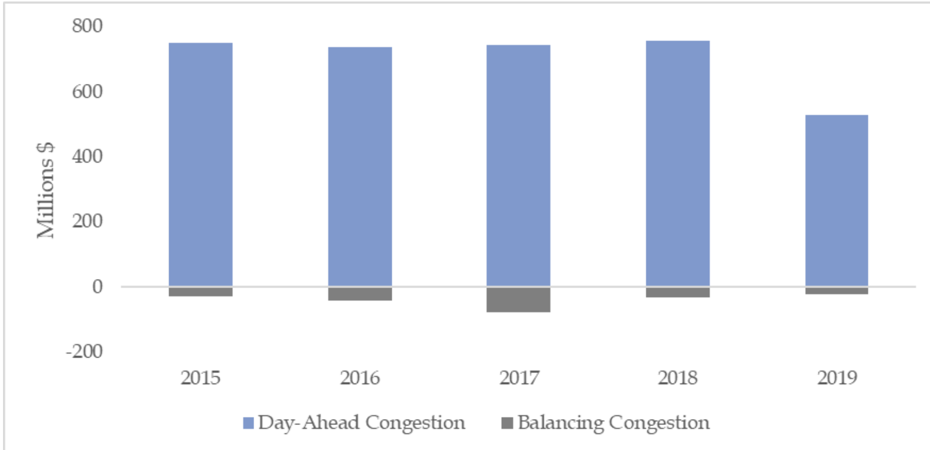


Sources: MISO; commercial third-party database.

In terms of congestion, as illustrated in Figure 120, day-ahead congestion has ranged between $737-$756 million over the period analyzed, except for the last year. In 2019, MISO experienced a decrease in its day-ahead congestion by 30% relative to 2018, totaling $528 million.[377] The reasons behind this reduction were new generation and transmission facilities, line upgrades, milder weather conditions, and lower natural gas prices. Conversely, balancing congestion peaked in 2017 to -$76 million and then went back to similar levels of 2015, reaching approximately -$22 million by 2019.

[377] Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020.

Figure 120. Day-ahead and balancing congestion, 2015-2019



Source: Potomac Economics. State of Market Report (2016, 2018, and 2019).

14.3.2 Brief history of the FTR market

The FTR market in MISO was implemented in 2005 when MISO established its spot market for energy. MISO's FTR construct's original purpose was to provide LSEs with a hedging mechanism against congestion charges collected in LMPs.[378] The first rendition of the MISO FTR mechanism did not have ARRs. ARRs were introduced in 2007 when there was a fair amount of (other) market design changes. MISO replaced its direct allocation of point-to-point FTRs with the direct allocation of point-to-point ARRs, followed by an auction for FTRs. In 2007, MISO also changed its annual schedule for ARR allocation and auction of FTRs to align with PJM's.[379]Additionally, MISO proposed a long-term transmission right ("LTTR"), which LSEs and other firm transmission customers can convert to equivalent point-to-point FTRs or use to collect FTR auction revenues. Like PJM's ARRs, MISO's LTTRs have an annual term, but can be renewed every year for up to 10 years.[380]

MISO also expanded its FTR auctions by providing its first multi-period monthly auction ("MPMA") in November 2013. The MPMA not only includes the remaining months in the planning period (as in PJM's monthly auction) but also some future seasons within the planning year[381] (see Section 14.3.6). MISO did this to provide benefits through expanded FTR terms,

[378] MISO. "Initial Filling of Open Access Transmission and Energy Market Tariff" under Docket Number ER03-1118-000. July 25, 2003. p. 20.

[379] FERC. "Order Accepting Long-term Transmission Rights Proposal and Revisions to Rules for Short-term Transmission Rights, Subject to Modification." May 17, 2007. (119 FERC ¶ 61,143).

[380] Ibid.

[381] FERC. "Order Accepting Tariff Amendments." August 2, 2013. (144 FERC ¶ 61,097).

improved price discovery, and the ability to reconfigure FTR portfolios frequently to better manage risk and align with expected congestion costs.

In 2014, MISO held a high-profile investigation against Louis Dreyfus Energy Services ("LDES") based on alleged FTR market manipulation. MISO's Independent Market Monitor referred the case to the FERC's Office of Enforcement due to LDES' virtual supply and virtual demand trades, which artificially increased congestion around the Velca node in North Dakota from November 2009 to February 2010. According to the FERC, the congestion increased the value of LDES' positions in the FTR market, which resulted in a net gain. Because of this, FERC ordered LDES to pay MISO a fee of $3.34 million plus interest and pay a civil penalty of more than $4 million. The trader involved in the manipulation was also penalized with a civil penalty of $310,000. Notably, however, MISO did not modify any of its FTR auctions rules or automated monitoring mechanisms because of this case. Unlike PJM's forfeiture rule, MISO uses a structured market monitoring approach to perform surveillance of market participant's behavior.[382]

14.3.3 FTR mechanisms

> ***MISO's ARR/FTR guiding principles***
>
> **Hedging**: Guarantee that LSEs meet reasonable needs;
>
> **Participating**: Incentivize engagement with the day-ahead market;
>
> **Price transparency**: Provide efficient price congestion hedges; and
>
> **Creating incentives**: Support new transmission investments.
>
> - MISO, "Level 200 – Auction Revenue Rights and Financial Transmission Rights," slide 6.

In MISO, ARRs and FTRs are only available as obligations.[383] As illustrated in Figure 121, MISO's ARR/FTR framework consists of three stages (i) annual ARR allocation, (ii) annual FTR auction, (iii) and the multi-period monthly auction.[384] The annual ARR allocation stage has a registration phase that allows market participants to register and convert their firm transmission service into ARR entitlements. The allocation phase follows: MISO assesses market participants' ARR nomination and determines the allocation of ARRs that are simultaneously feasible. The annual FTR auction enables market participants to convert their ARRs into FTRs (self-scheduling process), as well as buy, sell, and reconfigure their FTRs.[385] Lastly, the multi-period monthly auction aims

[382] XO Energy LLC. "Complaint of XO Energy LLC." Filling under FERC Docket Number EL-20-41-000. April 8, 2020.

[383] Although considered in MISO's manual, FTR options are still not available to market participants. See MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.7. p. 140.

[384] MISO. "2020-21 Annual Financial Transmission Rights (FTR) Auction Workshop." slide 5.

[385] In general, additional paths might be available in the FTR auctions than in the ARR allocation process due to reverse or counterflow bids.

to sell any residual capability,[386] while also being a marketplace for further FTR exchange among market participants.

Although at a high level, MISO's ARR/FTR framework looks similar to PJM, there are some minor differences across all stages. The following sections discuss MISO's ARR/FTR market construct while describing the major distinctions with PJM.

Figure 121. MISO's ARR/FTR construct

Source: MISO. "Level 100 – Auction Revenue Rights and Financial Transmission Rights." slide 6.

14.3.4 MISO's annual ARR allocation process

The first phase of the annual ARR allocation is the ARR registration. Year-1 of the ARR registration is a two-step process.[387] It begins with an initial data gathering that defines the set of ARR points of delivery and receipt, and the eligible transmission service (see textbox below). This step only occurs when a new market participant is first integrated. The points of delivery or "ARR zones" are geographic areas where LSEs served load during the reference year.[388] These locations are defined with the objective of allocating ARRs based on generation to load paths. Specifically, receipt points or Reserved Resources Points ("RSPs") are qualified generation resources historically used to serve the load located in the ARR zone during the reference year. All generation sources qualified as RSPs created the Peak Reserved Source Set ("PRSS"). PRSS is divided into three categories: Baseload Reserved Source Set ("BRSS"), High Utilization Factor Unit ("HUFU"), and remaining RSPs that do not meet the criteria to be either BRSS or HUFU. BRSS that qualify as RSPs must have had a capacity factor of at least 50% during a 3-year test period considering the reference year and two years before the reference year.[389] HUFU is an RSP

[386] Residual capability is typically the result of network model changes. However, another component might be market participants interested on counterflow positions that reduce the load on the system for the existent capacity allowing other market participants to acquire FTRs.

[387] MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.9. p. 41.

[388] The reference year is set from March 1, 2004 until February 28, 2005.

[389] MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.9.2.1. p. 48.

that does not meet BRSS conditions but instead has a utilization factor (or the percentage of hours online) of no less than 70% during the same 3-year test period previously defined for BRSS.[390]

The second step of Year-1 ARR Registration involves MISO reviewing and approving historical firm transmission services that are eligible to obtain an ARR allocation through "ARR Entitlements." These ARR Entitlements, which are only available in the form of gen-to-load paths, offset out the ARR paths that market participants are able to nominate in the annual ARR allocation.[391] These ARR Entitlements remain fixed unless MISO approves any requested adjustment.[392]

Eligible transmission services considered in the registration phase that might hold an ARR can be one of four types:[(a),(b)]

- **Firm Point-to-Point ("PTP")** valid during the reference year and roll over into the next annual ARR allocation period;
- **Network Integration Transmission Service ("NITS")** from resources historically used to serve the load that were valid during reference year;
- **Grandfather Agreements ("GFAs")** intended to maintain this condition or convert to tariff service;[(c)]
- **Multi-Value Projects ("MVP")** attempting to solve transmission issues and enhance network capacity between zones, across the MISO footprint.

Note: (a) MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.7. p. 32; (b) Refer to Figure 118 above on how transmission costs are allocated; (c) Each GFA responsible entity that wants to keep the service under a GFA must choose one of three options (A, B, or C) related to different treatments in ARR scheduling and settlement of transmission congestion and losses, unless it has been carved out by FERC order under docket numbers ER04-691-000, ER04-106-002, EL04-104-000. The entity can also convert the GFA to tariff service, however, this decision cannot be reverted. For further details, see MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.8.3.

Once the ARR registration process is complete, MISO conducts the second phase of the annual ARR allocation, known as the ARR nomination/allocation, in which market participants decide

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390 MISO Southern Region has a different test period. It is defined from June 1, 2010 through May 31, 2012. See MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.9.2.1. p. 50.

391 Year-2 and beyond of the ARR registration process is simpler as MISO can rely on ARR Entitlements previously defined as valid. Market participants are then requested to accept or reject their previously granted ARR Entitlements through the MISO Market Portal. If accepted, market participants need to review them and submit any modification. MISO will verify that the review process is completed and confirm that any change submitted is supported by the required documentation.

392 ARRs adjustments includes load switch (re-assignment), RSP modifications (addition, replacement, or termination), new PTP additions, and network upgrades. See MISO, "Level 200 - Auction Revenue Rights and Financial Transmission Rights." slide 31.

the amount of ARR Entitlements that they want to nominate – these are then referred to as Candidate ARRs (also known as "CARRs"). CARRs will be converted into ARRs obligations subject to simultaneous feasibility.

This second phase consists of a multi-stage process (Stage 1A, Restoration, Stage 1B, and Stage 2) that allows not only the nomination/allocation of ARRs but also the termination of previously assigned LTTRs and the assignment of rights to unallocated ARRs to receive the excess FTR auction revenues (see Figure 122).

Under **Stage 1A**, transmission customers may request ARRs obligations with a BRSS up to 50% of the peak usage.[393] Stage 1A includes eight independent nominations, resulting from combining four seasons (winter, spring, summer, fall) and two time of use (peak and off-peak).[394] In contrast, PJM's Stage 1A allows ARR allocation to the minimum daily peak load from the previous year (the defined baseload). An empirical comparison of the amount of ARRs allocated by MISO and PJM based on actual hourly load data for each zone in PJM indicates that, on average, MISO enables a larger allocation of ARRs than PJM through its Stage 1A allocation process.[395] This is not surprising given that there is less congestion currently on the MISO system. MISO assesses all Candidate ARRs by running an SFT to determine the amounts of ARRs that could be awarded. The SFT is performed to avoid the overallocation of ARRs, which could lead to the underfunding of ARRs. ARRs granted in Stage 1A are known as Long-Term Transmission Rights. Like PJM, in compliance with the requirements under FERC's changes due to EPAct 2005, LTTRs are guaranteed allocations for ten years (annual rollover rights). Therefore, unless their termination is requested and approved subject to SFT, LTTRs will be automatically pre-populated in next year Stage 1A nomination process.

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[393] Peak usage is defined as "*A Market Participant's Total Forecasted Peak Load in a given ARR Zone for the upcoming Annual ARR Allocation Period calculated using the immediate prior three years actual peak Loads. The Total Forecast Peak Load is the sum of the forecast Network Integration Transmission Service Peak Load for the upcoming allocation period plus peak Load served by Option A – Grandfathered Agreements plus peak Load served by Option B – Grandfathered Agreements.*" MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.7. p. 41.

[394] MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.11.3. p. 77.

[395] LEI has conducted an exercise based on the current rules applied by each RTO under Stage 1A using daily peak load data of several PJM's zones for the period between October 22, 2016 and October 21, 2019. The results show that, on average, MISO is able to allocate more ARRs than PJM during Stage 1A for a same peak load profile.

MISO then moves on to the **Restoration Stage**. This stage has no active LSE engagement. Rather, this stage of the ARR process requires that MISO determine whether it needs to do anything to restore all or a portion of curtailed Stage 1 CARRs and LTTRs using counterflows ARRs.

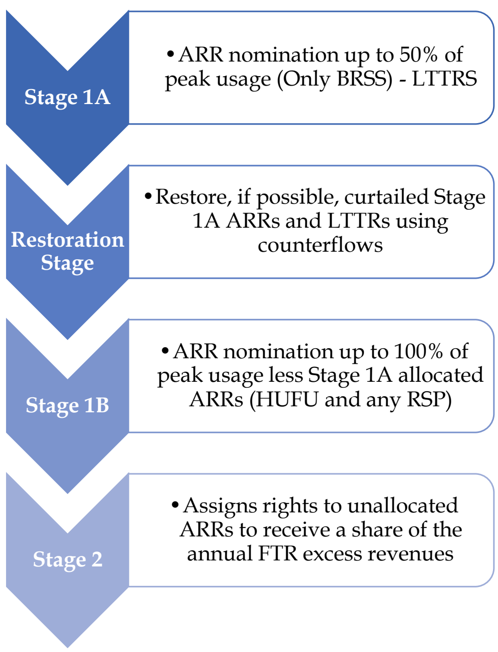
Available counterflows ARRs[(a)] are also in the form of obligation and can be any of the following three types:[(b)]

- ARR Entitlements not nominated in Stage 1A;
- LTTRs termination requests submitted during Stage 1; and
- ARR Entitlements defined from a HUFU Reserved Source Point.

Notes: (a) As forward-flows ARRs, counterflows ARRs are one direction from source to sink; (b) MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.11.5.2. p. 81.

MISO evaluates the LTTRs termination request and identifies which are needed to counterbalance the curtailed CARRs and LTTRs from the previous stage. In case they are required, MISO considers these paths as counterflows and moves to deny the LTTR termination request. Therefore, MISO only allows a market participant to terminate LTTRs that are not required to honor other market participants' CARRs or LTTRs. In contrast, PJM does not allow the participants to terminate an ARR once it has approved the rights. The restoration process uses an SFT that seeks to simultaneously maximize the amount of MW restored and LTTR termination requests granted.

Figure 122. ARR nomination/allocation process



Source: MISO, "Level 200 - Auction Revenue Rights and Financial Transmission Rights." slide 32.

In **Stage 1B**, market participants may request ARRs obligations with a HUFU or any RSP in the PRSS up to 100% of peak usage, subtracting the ARRs allocated in Stage 1A subject to simultaneous feasibility. Like Stage 1A, Stage 1B considers the same eight independent nominations. During this stage, MISO also automatically nominates infeasible ARRs resulting from the Restoration stage and CARRs from MVP.[396,397]

Any remaining CARRs not allocated during Stage 1A and the Restoration Stage will be considered in Stage 1B as "Infeasible ARRs". If they are unable to be allocated during Stage 1B, MISO will still allocate them as infeasible ARRs subject to the same settlement process as other ARRs.[398] However, they will be funded by an uplift charge paid by LTTRs holders (see Section 14.3.7).

In addition to Stage 1A and 1B nominations, market participants have the opportunity to request additional CARRs as the result of load growth increments during the planning year. Network upgrades are also an alternative to get ARRs based on the capability resulting from the additions and modifications and their consistency with previously assigned ARRs. If allocated, these ARRs are known as Incremental Long-Term Transmission Rights ("ILTTRs").

Unlike in the earlier stages**, Stage 2** does not have an additional nomination process. MISO entitles market participants with unallocated ARRs Entitlements (i.e., the difference between ARR previously allocated and its nomination eligibility) to receive a portion of the excess revenues from the annual FTR auction based on the share of each market participant unallocated ARRs over total unallocated ARRs. MVP ARRs, however, are not included in Stage 2 allocation. This stage differs significantly from PJM's Stage 2 as market participants in PJM can still nominate specific ARRs to fulfill the rest of their peak load.

In case any transmission owner joins the MISO system after the ARR annual allocation, MISO offers LSEs within the transmission owner system the possibility of hedging their congestion through a partial-year FTR allocation for the remainder of the year (i.e., up to the beginning of the following annual ARR allocation). This partial-year FTR allocation will result from a single-round nomination and allocation based on historical transmission usage, capped to market participants' annual peak usage or PTP transmission service's volume. The products available will be peak and off-peak FTRs for each of the remaining seasons.

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396 MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.11.4. p. 79.

397 MISO will assign the revenues of MVP ARRs on a pro-rata basis to transmission customers in accordance with MVP-related rate schedules. See FERC. FERC Order in Docket No ER12-1194-000. September 18,2014 (148 FERC ¶ 61,204)

398 MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.7. p. 89.

14.3.5 FTR products

FTRs allow MISO market participants to hedge against transmission congestion costs in the day-ahead market. As mentioned earlier, MISO only issues PTP FTR in the form of obligations, as FTR options are not currently available.[399] These financial instruments' source and sink points can be Commercial Pricing Nodes ("CPNodes") in the form of a resource node, ARR zone, hub, load zone, and interface, similar to PJM. However, MISO does not allow market participants to bid on FTRs that have source and sink points within the same bus. Additionally, market participants may also request Incremental FTRs ("IFTRs") due to network upgrades contributing to congestion relief.

MISO FTR products are available for peak and off-peak and classified by season (fall, winter, summer, and spring) as well as monthly terms. Peak is defined as time-lapse from 7 am to 10 pm, except for specific holidays, from Monday to Friday. Off-peak is any remaining period not defined as a peak. PJM's FTR availability is less granular (i.e., it is annual and monthly but not seasonal); however, PJM also offers FTRs for an entire 24-hour period (which do not currently exist in MISO).

14.3.6 FTR auction mechanism

MISO conducts two types of auctions: annual and monthly. Unlike PJM, MISO does not have an LT auction for its FTRs. While both the annual and monthly auctions facilitate FTR transactions (i.e., buying, selling, and reconfiguration) among market participants, the annual auction also allows the conversion of ARRs into FTRs, similar to PJM's self-scheduling of ARRs. Participation in the FTR auctions is restricted to MISO members, comprised of transmission and generator owners, LSE, and other entities, such as financial traders.[400, 401]

MISO's **annual FTR auction** is a multi-round auction performed immediately after the annual ARR allocation, like PJM. The annual FTR auction consists of eight independent auctions due to the combination of two time of use periods (peak and off-peak) and four seasons (winter, spring, summer, fall). As illustrated in Figure 124, three rounds allocate the available transmission capability as follows: one-third (1/3) in the first round, half (1/2) of the remaining FTRs in the second round, and all remaining in the last round.[402] MISO also offers seasonal FTR products in the annual FTR auction (PJM currently offers annual and monthly FTR products). MISO's annual FTR auction has one less round as compared to PJM's annual FTR auction. Similar to PJM, MISOs

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399 Unlike FTR options, FTR obligations allow MISO to allocate more FTRs (i.e., the addition of two FTR obligations going in opposite direction results in a lower net flow and makes the SFT analysis less computation intensive).

400 Financial traders are required to meet MISO's credit requirements and registration process to participate in the FTR auctions (annual and MPMA). These markets participants do not own physical assets.

401 MISO. "Market Registration Business Practices Manual - BPM-001-r15." April 2020. Section 4.1. p. 22.

402 MISO. "Level 100 –Auction Revenue Rights and Financial Transmission Rights." slide 17.

ARR holders are allowed to convert their feasible ARRs into FTRs through a process known as self-scheduling during the first round of the annual FTR auction.[403] The MW eligibility across each round for self-scheduling ARRs follows the same structure as other FTRs.

As shown Figure 123 below, the proportion of self-scheduled ARR, represented by the self-schedule ARR ratio, has been declining between 2017 and 2019 in MISO. This trend is reflective of the observation in PJM, where most ARRs are held and not self-scheduled (see Section 6.2).

Figure 123. Self-scheduled and non-self-scheduled ("SS") ARR comparison in MISO

	Units	2017	2018	2019
Total ARR	MW	647,820	625,232	630,752
Self Scheduled (SS) ARR	MW	468,213	423,995	418,161
SS ARR Ratio	**MW**	**0.72**	**0.68**	**0.66**
NON SS ARR	MW	179,607	201,237	212,591
NON SS ARR Ratio	**MW**	**0.28**	**0.32**	**0.34**

Source: MISO. "2020 to 2021 Annual Allocation and Annual Auction Market Summary," June 2020.

In addition to the annual auction, MISO (like PJM's monthly auction) has a **monthly auction** to sell the remaining FTR capability and allow FTR holders to sell their acquired FTRs. As mentioned earlier, unlike PJM's single-round monthly auction that only includes the remaining months in the planning period, MISO's MPMA also offers FTR products for the remaining seasons.[404] The schedule of the 37 FTR auctions considered in MPMA within each planning period is depicted in Figure 125.

The FTRs awarded across MISO's FTR auctions need to be simultaneously feasible. Subscribed FTRs are checked under normal conditions to guarantee that MISO's transmission system is able to support the FTR auction assignment, meaning that the FTR allocation is revenue adequate. According to MISO's independent market monitor, counterflow FTRs could be used to reduce oversold transmission paths (especially during the multi-period monthly auctions).[405] For example, if there is a change in outages between the annual FTR auction and the MPMA, then a set of existing FTRs from the annual FTR auction on this new topology could overload MISO's monthly binding constraints.

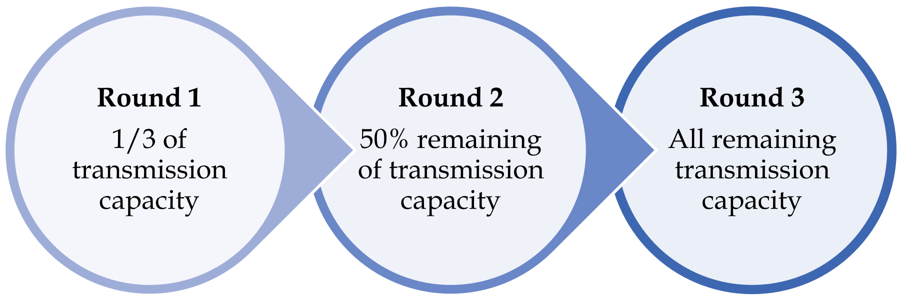
[403] Neither infeasible ARRs nor Stage 2 allocations are allowed for self-scheduling.

[404] MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 4.10.9.1 p. 147.

[405] Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. pp. 76-77.

Like PJM, FTRs could also be bought and sold in the secondary market. FTRs traded in this way must maintain their initial acquisition features, although market participants are allowed to split the original FTRs in terms of MW and date, similar to PJM. However, their reconfiguration, when added, must not exceed the original FTR specifications.[406]

Figure 124. Annual FTR auction overview



Source: MISO. "2020-21 Annual Financial Transmission Rights (FTR) Auction Workshop." slide 9

Figure 125. MPMA schedule

MPMA products available (peak and off-peak)							
Season	**Auction In**	**Auction For**					**Periods**
Spring	May	June					1
Summer	June	July	August	*Fall*	*Winter*	*Spring*	5
	July	August	September	October	November		4
	August	September	October	November			3
Fall	September	October	November	*Winter*	*Spring*		4
	October	November	December	January	February		4
	November	December	January	February			3
Winter	December	January	February	*Spring*			3
	January	February	March	April	May		4
	February	March	April	May			3
Spring	March	April	May				2
	April	May					1

Source: MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 5. p. 150.

14.3.6.1 Size of MISO's FTR market

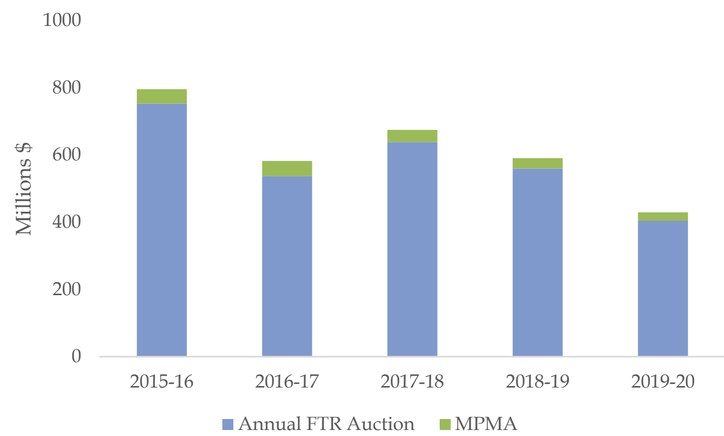
Net auction revenues show a decreasing trend during the last five planning years (see Figure 126 below). Indeed, net FTR auction revenues have declined from $795.9 million in 2015/2016 to

406 MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 5. pp. 151-152.

$429.8 million in 2019/2020. One of the main reasons for this decline is related to reduced congestion (due to network upgrades).

A simple comparison between MISO's auction types shows that, on average, the annual FTR auction accounts for approximately 94% of the net total auction revenues over the period analyzed, while the remaining comes from the MPMA.

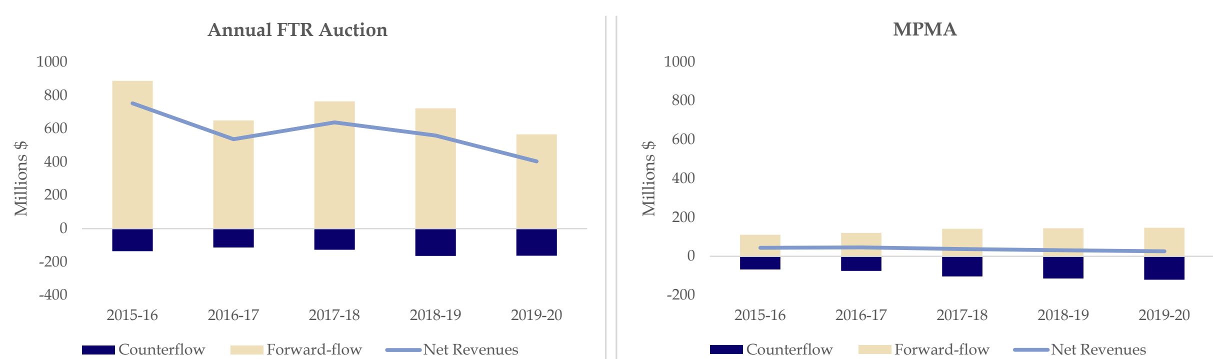
Figure 126. FTR net auction revenues, 2015/2016-2019/2020



Source: MISO. FTR Market Results. Website. Downloaded in November 2020.

As illustrated in Figure 127, counterflows have been a significant share of the MPMA auction revenues during the last three planning years. Indeed, in the planning year 2019/2020, counterflows account is almost (83%) the same magnitude as forward-flows. Conversely, in the annual FTR auction, forward-flows have been the majority of auction revenues over the entire period under analysis.

Figure 127. FTR auction revenues by flow type

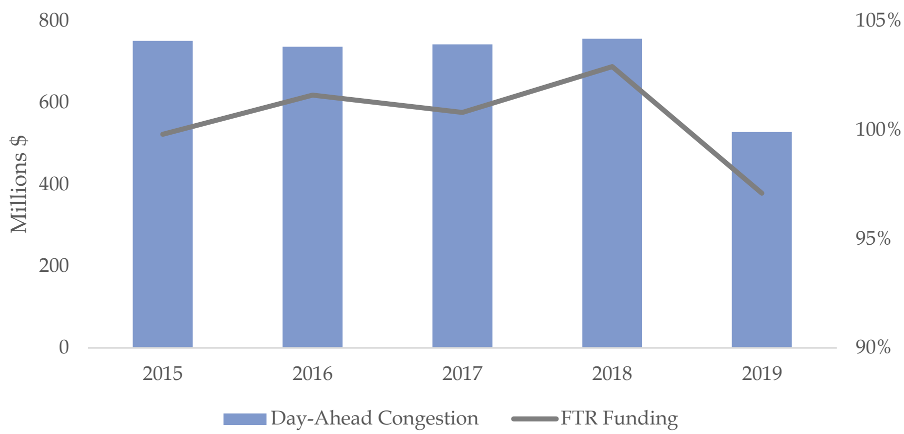


Source: MISO. FTR Market Results. Website. Downloaded in November 2020.

Day-ahead congestion rents decrease from $751 million in 2015 to $528 million in 2019. As mentioned earlier, in addition to a transmission system enhancement, other factors, such as mild weather and lower gas prices, have contributed to this reduction in day-ahead congestion charges. FTR funding has been around or over 100% except for 2019. According to the IMM in MISO, this underfunding has been caused mainly by planned and unplanned transmission outages not considered in modeling the FTR auctions.[407]

In 2017, MISO's IMM recommended various measures to improve MISO congestion management, including a review of ratings used by transmission operators and strategy to manage outage coordination, amongst others.[408]

Figure 128. Day-ahead congestion and FTR funding, 2015-2019



Source: Potomac Economics. State of Market Report (2016, 2018, and 2019).

With reference to the trend captured in Figure 129, the IMM also determined that the practice of market participants nominating self-scheduling ARRs along historically unprofitable paths has contributed to FTR losses.[409] However, this trend has reversed in the past few years, improving annual FTR profitability. MISO's IMM considers MPMA auctions as the least liquid amongst FTR products. The IMM's recommendations[410] included:

- reviewing the rules and requirements that may limit the participation in the FTR markets;

[407] Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. p. 59.

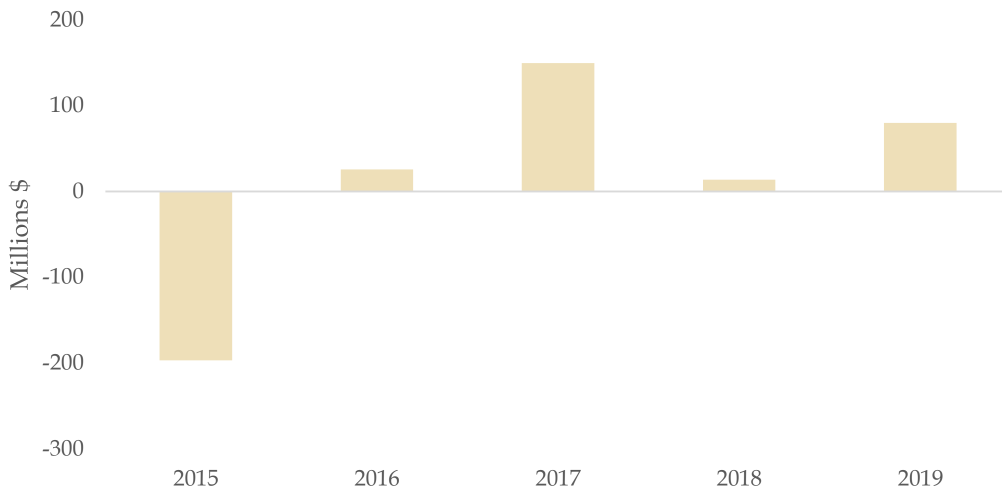
[408] Potomac Economics. "2017 State of the market report for the MISO electricity markets." June 2018. p. vi.

[409] Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. p. 75.

[410] Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. p. 77.

- removing the arbitrary negative auction residual restriction, which limits MISO's ability to sell counterflow FTRs, since there is no need to require each auction strip to have a positive residual; and
- examining the auction processes to determine whether to limit the sale of forward-flow FTRs at unreasonably low prices and/or the sale of counterflow FTRs at unreasonably high prices.

Figure 129. Profits in MISO's FTR auctions



Source: Potomac Economics. State of Market Report (2016, 2017, and 2019).

14.3.7 ARR settlement mechanism

As detailed in MISO's Business Practice Manual 4, the ARR settlement is calculated monthly using the annual FTR auction's clearing prices.[411] An ARR obligation's monetary value will be the difference between the auction shadow prices at the delivery and receipt point times the MWs allocated. Therefore, an ARR obligation will provide credits to its holder if the auction shadow price at the delivery point is less than the shadow price at the receipt point. Conversely, if the shadow price at the delivery is greater than the shadow price at the receipt point, the ARR obligation imposes a charge to its ARR holder.[412] Only MVP ARRs will have a different valuation as they can only have a positive value (i.e., they essentially act as "options"). In PJM, the IARRs are obligations.

[411] MISO. "FTR and ARR Business Practices Manual - BPM-004-r21." June 2020. Section 3.7. pp. 153-156.

[412] It is worth mentioning that for non-self-scheduled ARR the shadow price applicable will be an unweighted average of all-round clearing prices.

The revenues collected from the annual FTR auction are initially used to fund feasible ARRs. If there is any remaining ARR deficiency, MISO's ARR holders will receive a discount. PJM has different mechanisms to deal with this issue. ARR deficiencies might be covered by the excess congestion fund or, if needed, an uplift charge will be applied to the FTR holders with net positive allocation positions. On the other hand, MISO's Stage 2 allocations of the annual ARR allocation will be used to allocate any excess revenue after funding feasible ARRs, as described in Section 14.3.4. In contrast, in PJM, any remaining ARR deficiency at the end of the planning period is covered by FTR holders, which is advantageous to the load.

LTTRs holders will fund infeasible ARRs through an uplift charge calculated as the ratio between the total LTTR MW of each market participant over the total LTTR MW allocated among all market participants in the current annual ARR allocation.

14.3.8 FTR settlement process

FTR hedging outcomes

1. **Exposed:** Transmission congestion charges are not fully covered by FTR payments;
2. **Hedged:** FTR payments are equal to transmission congestion charges;
3. **Over-hedged:** Transmission congestion charges are surpassed by FTR payments.

- MISO, "Level 200 - Auction Revenue Rights and Financial Transmission Rights." slide 63.

According to MISO' Business Practice Manual 5, the FTR settlement process has three stages: hourly, monthly, and yearly.[413]

First, the hourly revenue allocation process determines the congestion dollars for each hour allocated to FTR holders based on day-ahead LMPs, namely the difference in marginal congestion component at the delivery and receipt points.[414] If the funds gathered from the day-ahead energy and operating reserve market in the same hour are sufficient, an FTR will be fully funded. Conversely, if fewer congestion revenues are collected for that hour, then FTR holders will be paid on a pro-rata basis. This shortfall might be covered if excess revenues are available during the monthly and/or yearly revenue allocation process.

Second, the monthly revenue allocation process occurs if excess funds have been collected during the calendar month due to total congestion for an hour being greater than the revenue required to cover FTRs for the same hour. Under this situation, FTR holders who have not been fully covered in the same calendar month will receive the available amounts prorated based on their target revenue allocation.

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[413] MISO. "Market Settlements Business Practices Manual - BPM-005-r19." February 2020. Section 2.9.3. pp. 73-75.

[414] Like PJM, balancing congestion is allocated to load and exports on a pro-rata basis. See Potomac Economics. "2019 State of the market report for the MISO electricity markets." June 2020. p. 59.

Finally, the annual revenue allocation process is settled, funded by unallocated revenues from the monthly process. This final stage is meant to cover FTR holders who have not received their full target allocation during the same calendar year (on a pro-rata basis). Transmission customers receive any excess remaining at the end of the year `per MISO's Tariff.[415] Conversely, any shortfall is allocated to FTR holders on a pro-rata basis according to their target allocation.[416] In PJM, any remaining surplus or revenue deficiency at the end of the planning period follows a different allocation process. Excess funds at the end of the planning year are allocated pro-rata to ARR holders based on their net positive ARR Target Allocation position, while any FTR revenue deficiency is covered through an uplift charge, paid only by FTR holders with net positive FTR Target Allocation position on a pro-rata basis, which is, in turn, set based on the net positive FTR Target Allocation position of all FTR holders. In other words, any remaining excess is allocated to ARR holders in PJM, while it is assigned to transmission customers (regardless of holding FTRs) in MISO. On the other hand, any shortfall in MISO is allocated to FTR holders as a discount, while this results in an uplift charge only applicable to FTR holders with net positive allocation positions in PJM.

[415] MISO's Tariff describes this process as follows: "*To the extent FTRs are fully funded and there is a surplus of funds in the Excess Congestion Fund, the aggregate remaining excess revenues attributable to the year-end Excess Congestion Charge Fund will be distributed to all Transmission Customers taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service based on a pro rata share of their billing determinants used in calculating the Schedule 10 charges and Schedule 23 charges associated with such Transmission Service taken during the same calendar year, regardless of whether these Transmission Customers hold FTRs for their Transmission Service.*"

[416] Doying, R. (Testimony on behalf of MISO). "Initiating Investigation of the potential costs and benefits of Entergy New Orleans, Inc. and Entergy Louisianan, LLC. joining a Regional Transmission Organization versus continuation of the Entergy Independent Coordinator of transmission with enhancements." Council of the City of New Orleans. Docket Number. UD-11-01. March 23, 2012.

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16 Appendix H: About London Economics International LLC

LONDON ECONOMICS INTERNATIONAL LLC

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm also has in-depth expertise in economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design and analysis. LEI has worked extensively in North America, Europe, Asia, Latin America, Africa, and the Middle East, and has a comprehensive understanding of the issues faced by the utilities and regulators alike.

The following attributes make LEI unique:

- *clear, readable deliverables* grounded in substantial topical and quantitative evidence;
- *internally developed proprietary models* for electricity price forecasting incorporating game theory, real options valuation, Monte Carlo simulation, and sophisticated statistical techniques;
- *balance of private sector and governmental clients* enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;
- *ability to estimate relative efficiency levels* and efficiency frontiers provides expertise to advise on network tariffs and design rates under performance-based ratemaking; and
- *worldwide experience* backed by multilingual and multicultural staff.

LEI has significant experience in several areas, including:

ELECTRICITY: London Economics International LLC has participated in the birth and development of competitive electricity markets worldwide. Our strategy practice has helped traditional IOUs in the creation of competitive gencos, assessment of the establishment of independent transcos, and valuation of synergies with associated businesses. Market design achievements include use of game theoretic techniques to assess bidding strategy and creation of sophisticated contracting structures to mitigate market power.

WATER: LEI's water and wastewater, and collection system sector services include advising on water utility management, tariff rate-setting and regulatory frameworks, PBR, water demand management programs, and freshwater supply, treatment and distribution systems. LEI has advised water and wastewater industry clients ranging from power and water utilities to government regulators and financial institutions in Europe, Africa and the Middle East.

NATURAL GAS: LEI's natural gas related activities include assessment of the synergies between the natural gas and electric power industries, examination of performance-based ratemaking and total factor productivity for natural gas distribution companies, and developing screening methodologies for potential investments in the natural gas industry.

RENEWABLES: LEI provides a range of services associated with the renewable energy industry. This includes working with developers to value potential revenue streams from renewable energy credits (RECs) and/or emissions offsets, advising private equity funds to craft investment plans targeted at "green" technologies, and counseling governments and regulators on creating policies which efficiently incentivize investment in renewable energy.

TRANSPORTATION: London Economics is at the forefront of analyzing key issues related to pricing and privatization of key transportation infrastructure. This includes analysis of the implications of road pricing, regulation and development of privatized ports, and lessons from the UK rail privatization process.

LONDON ECONOMICS

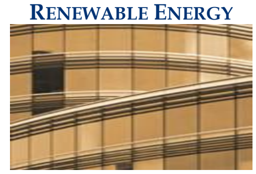
ASSET VALUATION, PRICE FORECASTING & MARKET ANALYSIS

REGULATORY ECONOMICS, PBR & MARKET DESIGN

EXPERT TESTIMONY & LITIGATION CONSULTING

TRANSMISSION

RENEWABLE ENERGY



PROCUREMENT