CONFLICTS OF INTEREST IN AUCTIONS FOR FINANCIAL TRANSMISSION RIGHTS

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Overview

Auctions for Financial Transmission Rights (FTRs) are a mechanism to reimburse load-serving entities (LSEs) for expected congestion payments they will incur in the energy market, while simultaneously making a financial product available for use as a hedging instrument. Recent analysis shows that FTR auctions are persistently profitable for financial speculators and that, on average, congestion rent paid by LSEs exceeds reimbursement.[1] One common explanation for the revenue shortfall is that price formation is inefficient in FTR auctions (Olmstead, 2018). In this paper, we explore an alternative explanation for persistent congestion reimbursement shortfalls, which is the presence of trading premia demanded by financial speculators. Essentially, the trading premium of an FTR adjusts the FTR's bid price to account for the market participant's risk aversion and/or transaction costs.

In this paper, we develop a theoretical framework that describes the roles of supply, demand, and trading premia in determining an LSE's expected revenue from FTR auctions. Even when the FTR auction market is fully competitive, the presence of trading premia facilitates a transfer of wealth from electricity customers to FTR holders. Furthermore, we study how the ownership structure of generating resources and LSEs in a competitive electricity market affects the congestion reimbursement received by electricity customers through FTR auctions.

There are a handful of dominant corporations, called investor-owned utilities (IOUs), that own both generation resources and regulated utilities in competitive electricity markets. One such company owns six regulated utilities and as many as two dozen competitive generators that operate in the PJM Interconnection. Because this company owns regulated utilities that serve load in PJM, they receive Auction Revenue Rights (ARRs) to offset congestion rents incurred by these utilities. Moreover, because this company owns and operates baseload generating stations in PJM, they purchase a substantial quantity of FTRs to hedge locational basis risk faced by their generating stations. These generating stations generally operate in the same territory as their regulated utilities. Thus, this IOU has competing interests in PJM's annual FTR auction. On one hand, they want to purchase locational basis hedges for their generators at the lowest price possible. On the other hand, they want their regulated utilities to receive the maximum value for their ARRs.

Methods

We begin by developing a theoretical model that describes equilibrium outcomes in FTR auctions under various ARR management strategies. This framework explores how the LSE's ARR configuration strategy impacts the quantity of FTR transmission capacity available to hedgers and speculators in the auction. In the mathematical formulation of the auction clearing process, transmission capacity is modelled explicitly as the right-hand-side values for each transmission constraint. The majority of the network transmission capacity is allocated to LSEs in the form of ARRs. As the LSE self-schedules more ARRs into FTRs, there is less "free" transmission capacity available to other bidders. Transmission capacity (i.e. market supply) beyond the ARR allocation is created either by an FTR holder offering to sell a previously acquired FTR or an auction participant bidding to purchase a counterflow FTR. The LSE's expected payoff from their ARR management choice depends on who (e.g. hedger or speculator) is the marginal bidder along the ARR path and the direction/magnitude of the marginal bidder's trading premium.

We explore empirical evidence regarding the predictions of the theoretical framework in the Commonwealth Edison ("ComEd") transmission zone of PJM. This zone is a useful case study because the investor-owned utility, Exelon, owns the regulated utility ComEd as well as several nuclear power plants that serve the ComEd region under a separate subsidiary, Exelon Generation. We study the ARR management strategies in this transmission zone and their realized payoffs as well as the cost-effectiveness of FTR hedges purchased by participants who own physical assets.

We then extend our analysis to investigate two implications of the theoretical framework. First, we wish to test if an LSE's ARR management strategy impacts the LSE's expected payoff of their ARR allocation. Specifically, we test whether self-scheduling more ARRs into FTRs increases the expected payoff of an ARR allocation. To do this, we specify the following econometric model:

[1] The work of California ISO's Department of Market Monitoring and PJM's independent market monitor highlight this fact and has received attention in their respective ISO/RTO stakeholder processes. See also Leslie (2018).

$$TA = \beta_0 + \beta_1 AP + \beta_2 ARR + \beta_3 SS + \sum_{i=4}^{13} \beta_i \, Year_i + \sum_{i=14}^{33} \beta_i \, Region_i$$

where TA is an FTR's target allocation (in \$/MW), AP is the auction price of an FTR (in \$/MW), ARR is the quantity of an ARR allocation (in MW), SS is the quantity of an ARR allocation self-scheduled into FTRs (in MW), and Year and Region control for yearly and regional fixed effects due to weather and other omitted variables. The data used in this regression is the set of ARR allocations in PJM from 2007-2017.

Second, we wish to know if the ownership structure of LSEs and generating stations in a given region could impact the degree of competitiveness in the region through imbalanced access to hedging products. So, we ask the question: Are Exelon Generation's hedges more cost-effective than their rivals' hedges in the ComEd region? To answer this question, we specify the following econometric model:

$$TA = \beta_0 + \beta_1 AP + \beta_2 Exelon + \beta_3 AP * Exelon + \sum_{i=4}^{13} \beta_i \, Year_i$$

where Exelon is a dummy variable that equals one when the purchaser of the FTR is Exelon. The data used in this regression are observations of FTRs purchased by owners of physical assets in PJM's annual FTR auction within the ComEd transmission zone over the period 2007-2017. Our parameters of interest are β_2 and β_3, which correspond to the payoff of Exelon's FTRs versus other hedgers. If Exelon has access to more cost-effective hedges than its rivals, then one or both of β_2 and β_3 should be positive and statistically significant.

Data used in this study are publicly available on the PJM website. PJM publishes ARR allocation results several months after the conclusion of the annual auction. The ARR results includes the source and sink nodes and the cleared MW quantity of ARRs. PJM does not report the quantity of ARRs that are self-scheduled into FTRs along a given path, nor do they publish the recipient of ARRs. However, we can derive self-schedule quantities by leveraging our knowledge of PJM rules regarding how self-scheduled FTRs clear the FTR auction. Data for FTR settlements come from the Hourly LMPs for the Day-Ahead Energy Market.

Results

Preliminary results are consistent with the implications of the theoretical model. From 2007-2017, the vast majority of ARRs were claimed as auction revenue as opposed to converted into FTRs in the ComEd region. Despite annual reimbursement shortfalls attributable to claiming ARRs as auction revenue, ARR management strategies in ComEd did not change considerably in the study period. In total, electricity customers lost \$326 million due to ARRs not being converted into FTRs.

On the other hand, Exelon Generation was able to acquire cost-effective hedges from 2007-2017. In total, Exelon was able to purchase FTRs at \$131 million below market value. Our theoretical model attributes the ability to purchase below-market FTRs to the substantial transmission capacity made available in the ComEd region along Exelon Generation's hedging paths.

Conclusions

A conflict of interest arises in auctions for Financial Tranmission Rights when an investor-owned utility owns a regulated utility and generating stations in the same region. The IOU has a strong market incentive to minimize the cost of hedging their fleet of generators, but the incentive to maximize the value of the regulated utility's ARRs is weakened due to public utility rate structure. We find that ARR allocation management strategies were not profit maximizing in the ComEd region from 2007-2017, but Exelon Generation was able to acquire cost-effective hedges for its generating resources. Beyond the loss of surplus experienced by electricity customers in ComEd, Exelon's ability to acquire more cost-effective hedges than rival generating stations could impact the degree of competitiveness in the power generation industry in this region.

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