Efficiency of New York Transmission Congestion Contract Auctions

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Abstract

Modern electricity market design is dominated by locational marginal pricing (LMP) of energy and transmission, coupled with periodic auctions of financial transmission rights (FTRs or TCCs) to hedge congestion price risks. For these market designs to be effective, participants must be able to efficiently discover forward locational prices. With data from monthly TCC auctions in New York, we use time series ARCH-ARMA models to postulate how clearing prices for TCCs are formed and the resulting implications for market efficiency. This analysis confirms recent studies suggesting that these auctions remain highly inefficient, even after allowing for risk aversion among bidders in the auctions.

1. Introduction

The design of effective market mechanisms for electric power has proved especially difficult, given the nature of electricity as a commodity. Electricity cannot be easily stored, so the generation and demand for power on the grid must be kept within a close tolerance at all times. Moreover, the production and transmission of alternating current (AC) power is subject to a number of inter-temporal and spatial constraints, given existing thermal power plant technology and the limitations of power flows on the grid [15]. The nature of these constraints makes power market design especially critical if the benefits of competition are to be realized while preserving the reliability of the bulk power grid.

Developing effective market mechanisms for power is especially difficult as AC power flows on the path of least impedance, and cannot normally be channeled to flow down any one line on the grid. As the individual components that make up the grid have limited power flow capabilities, any transaction for energy has the potential to congest the grid. To maintain reliability, it is necessary for power flows across hundred or thousands of different grid elements to be limited by the grid operator. Under most recent market designs, users of the transmission grid see transmission prices that incorporate the externalities of congestion impose on other users of the network.

1.1. Pricing congestion on the electric grid

As with other externalities, pricing of congestion on interconnected electricity networks has been tackled using Pigouvian and Coasian approaches. Under the Pigouvian approach, the grid operator requires full information on the state of the transmission and generation system, as well as supply offers for all generators and demand bids for all loads. Given this admittedly large set of information, the grid operator can then compute optimal "locational marginal prices" (LMPs) at each point on the grid and production schedules for each supplier.

Alternatively, it might be possible to define tradable property rights in the network, so that the traders themselves could incorporate these congestion effects in their transactions [4]. These Coasian approaches rely on the theoretical insights of Chao and Peck [3], who have demonstrated that such a system could in theory reproduce the efficient dispatch, if a separate transmission right was created for each constrainable element of the transmission grid. This theoretical approach, sometimes known as flow-based or flowgate rights trading, has been stymied by the number of potentially congestible network components. Unless limited to a smaller subset of flowgates determined to be commercially significant, such flow-based systems might thus create large transactions costs. On a complex and heavily-looped grid, such as operated by the New York Independent System Operator (NYISO), there are tens or hundreds of possible transmission constraints that can bind in an hour in the real-time operation of the system [11]. Although completely decentralized trading methods might work in a forward timeframe, they would appear to be impractical for use in real time, and the Federal Energy Regulatory Commission (FERC) has adopted the centralized LMP approach as the cornerstone of its proposed Standard Market Design (SMD) framework for the future of the U.S. power industry [7].

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1.2. Transmission congestion contracts

The essence of the LMP approach is that all operational decisions will be made by the grid operator, and that power produced and consumed is traded at the locational spot power price. As implemented in the market operated by the New York Independent System Operator (NYISO), for financial settlement purposes generators are considered to generate at their bus, while loads are considered to consume at their load zone. For example, a generator who produces 100 MWh in an hour at a node near Rochester will be will be paid 100 times the price at that node for the hour, and that a load of 10 MWh on Long Island will pay 10 times the Long Island zonal price.

Although this system is effective at addressing the realities of AC power flow, on its own it poses substantial financial risks for both generators and users of power. Spot power prices are highly volatile, and few users can expect to be located at or near a generator with whom they could contract. Some method is needed to hedge the price risks posed by spot power prices that vary from location to location.

Under the LMP framework, the marginal cost of any transmission is the difference in the congestion and loss components of locational spot prices between locations. For example, if the generator in Rochester wished to sell power at a fixed price to a customer in Long Island, it would be at risk that the Long Island LMP might be significantly higher in some hours than the Rochester price it will be paid by the grid operator. Similarly, if a load in New York City wished to contract to purchase power from a generator in Albany, it would face the additional risk that NYC prices can (and often are) much higher and more volatile than Albany prices.

In response to this problem, Hogan [10] proposed a system of financial hedging contracts designed to mitigate the component of this risk associated with congestion. These financial hedging contracts — fundamentally similar to financial swaps — pay the owner of the congestion contract the quantity (in MW) times the price difference between a specified Point of Injection (PoI) and Point of Withdrawal (PoW) for each hour in the term of the contract. These transmission congestion contracts (TCCs) or financial transmission rights (FTRs) play the role that ordinary point-to-point transmission rights play in physical market designs, although in this case they act solely as swaps and have no effect on system operations.

An example of a monthly TCC might be defined with a PoI of Albany and a PoW of New York City. For each hour in the month, the TCC holder is paid the difference between the NYC and Albany congestion prices. As noted previously, the LMPs in New York also include a locationally-specific marginal loss component. This element of the LMP is not included in the TCC structure and is not considered in the present analysis. Note that a TCC payment over an hour (or even over a month) can be negative — a TCC is normally is a financial obligation and not an option.

In a result that has had major implications for power market design, Hogan [10] showed the merchandizing surplus obtained by the grid operator was sufficient to fund a full set of TCCs that reflected the maximum physical simultaneous transfer capability of the transmission grid. Thus, if the grid operator auctions or allocates as many TCCs (in megawatt terms) that it could sell as physical transmission rights, its receipts will be sufficient to make the aggregate difference payments to TCC holders. This principle underlies the TCC auctions that occur in the NYISO market, the FTR auctions of other Northeastern ISOs, and the congestion revenue rights auction that comprise an essential component of the FERC's standard market design plans for the remainder of the country.

1.3. TCC auctions

NYISO was one of the first markets to fully adopt the LMP system, along with the neighboring PJM (Pennsylvania-New Jersey-Maryland) market. The core of the market structure used in New York and PJM has been proposed by FERC as the benchmark market design for use in the entire U.S. power industry. This proposal has proved controversial in many parts of the United States.

The periodic auctions in which TCCs are sold to market participants have been a key feature of the NYISO market since it opened in November 1999. Market participants include generators, transmission owners and marketers, including financial participants such as hedge funds. In New York, TCCs are sold for varying durations – one month, six months, and one year. The TCCs sold are made feasible either by unallocated transmission capacity associated with expired TCCs, or by TCCs sold on behalf of third parties in its reconfiguration auctions. Because they lend themselves more easily to analysis, one-month TCCs are the focus of the present research.

As noted previously, a one-month TCC is the right to hourly differences between congestion prices at two specified locations for the period of a calendar month. Since the TCC is defined as an obligation, and not an option, it may have a negative value, in which case a reverse auction is used to allocate it. An auction of TCCs covering a month is conducted in the middle of the preceding month, so that a TCC covering the month of November, for example, will be auctioned in mid-October. By focusing on monthly TCCs, which by design are never overlapping in coverage, statistical issues associated with overlapping observations are avoided.

2. TCC market efficiency analysis

The financial transmission rights used in the New York LMP/TCC framework comprise an economically consistent approach to power market design, which allow price risks to be hedged separately from system operations. Under this model, the hedging transactions (purchases and sales of TCCs) are independent of generator and grid operations, allowing the grid operator the ability to centrally dispatch all generation units to meet transmission reliability constraints at least cost and determine hourly marginal prices for all loads. The LMP model does have its drawbacks, however, and critics have suggested that the model as implemented in New York has traded one set of problems for another.

One of the biggest weaknesses of LMP markets, according to critics, is that locational forward price discovery is typically weak [14]. Under the LMP design, the NYISO, which holds full information on the state of the transmission system, primarily focuses on creating efficient hourly spot prices. Even in these LMP markets, however, the majority of trade is in (bilateral) forward markets, which are traded on expectations of future locational spot prices. Market participants must be able to form reasonable expectations of future locational prices if forward market liquidity is to be maintained and the allocative efficiency of forward prices is to be preserved. LMP, say critics, fails this important test.

Given the importance of expectations in creating efficient forward market outcomes, and the FERC's stated desire to use the New York and PJM LMP market models as the preferred platform, there has been an upswing in quantitative and semi-quantitative studies examining how well these and other power markets have performed in practice.

2.1. Review of existing studies on power market efficiency

Until the last few years the majority of economic analysis of power markets has had its antecedents in the industrial organization literature, much of its focusing on imperfect competition in transmission-constrained power markets [13]. Only recently has there been an upswing in the number of studies examining the performance of actual markets, with the exception of several well-publicized analyses of market power during the California electricity crisis of 2000-2001.

DeVany and Wall [6] examined the efficiency of Western transmission prices using a co-integration approach and price index data. This paper, however, analyzed only a small number of locational prices and focused on a decentralized bilateral-based market in the Western United States rather than the centralized LMP approach now advocated by FERC. Arcinegas, Barrett and Marathe [1] examined the very short-term trading efficiency of the New York, PJM and California markets, focusing on the relationship between day-ahead and real-time (hourly) spot prices. No analysis is included of TCC/FTR or other longer-term contract markets. Borenstein, Bushnell, Knittel and Wolfram [2] have similarly examined inter-temporal price convergence between day-ahead and real-time prices in the non-LMP California market. Saravia [14] has conducted a similar analysis for the New York market.

Outside of the United States, Gjolberg and Johnsen [8] have explored the forward pricing dynamics in the Nordpool market in Norway and Sweden. These authors conclude that the Nordpool market remains inefficient, while examining patterns in convenience yields in these storage-based hydro systems.

To our knowledge there has been only one published study to date on the TCC and FTR auctions that underlie current federal policy in power market design. Siddiqui, Bartholomew, Marnay and Oren [16] have conducted an initial analysis of NYISO TCC auction efficiency by direct comparison of auction prices against out-turn spot prices. The paper includes a few OLS estimates, and concludes that the initial TCC market was highly inefficient. This analysis, while revealing, examined only four auctions in the early years of the market (and hence is based on only four independent data points) [12]. The inefficiencies reported may also be a combination of both poor forward price discovery and understandable risk aversion in a new and untested TCC market and auction structure. A more complete and rigorous analysis is therefore required to understand the efficiency properties of these TCC markets, with the view of better understanding TCC auction design, price discovery processes, and bidder behavior.

The Siddiqui, Bartholomew, Marnay and Oren analysis may also suffer certain methodological problems, as it relies on ordinary least squares (OLS) estimation. Least squares estimation is inefficient in the presence of autocorrelation, and inference based on OLS can be biased. [9]. Examination of the auction and spot prices suggests that autocorrelation is a significant factor, as is common in time series data. Additionally, examination of residuals reveals that the auction and spot price data show considerable heteroscedasticity, which further undermines the use of OLS.

Two further developments provide further insights into the TCC auction price problem. Deng, Oren and Meliopoulos [5] claim to demonstrate by examples that a TCC auction will not produce prices that reflect the underlying spot prices, even if bidders have perfect foresight of average congestion rents. In early June 2004, the NYISO reported that existing transmission contracts had been omitted in accounting for the amount of transmission capacity available in the auctions going back as far as late 2002. The effect on historical TCC auction prices is yet unknown.

3. Methodology

The objective of our analysis was to evaluate the efficiency of the NYISO TCC market by comparing TCC auction prices to relevant day-ahead congestion price differences for a set of one-month TCCs. This section provides an overview of the data requirements and the econometric approach used in the analysis.

3.1. Data collection

All monthly TCC price data for the period November 1999 (when the New York market opened) to April 2003 was obtained from the NYISO website, and aggregated into a SQL Server database. For each TCC selected for analysis (50 TCCs for which the largest time series of actual auction prices were available), the sum of hourly spot congestion price differences over the contract month between the relevant PoI and PoW was calculated.

3.2 Estimation of predicted spot prices and variances

In the first stage of the analysis, predicted spot prices and variances for the contract month were created using univariate historical spot price data (monthly sum of price differences between the PoI and PoW of the individual TCC) available before the monthly auction. Since the monthly TCC auctions in NYISO are midway through the proceeding month, the data used ranged from month T_0 (November 1999, when the NYISO started operations) to month T_{n-2} where *n* is the contract month.

After differencing, the available price data was fit to an ARCH (autoregressive conditional heteroscedasticity) model with ARMA (autoregressive moving average) terms using maximum likelihood estimation (MLE). The generalized model was of form:

$$P_t = \alpha + \beta_{AR(1)}(P_{t-1} - \alpha) + \beta_{AR(2)}(P_{t-2} - \alpha) + \ldots + \beta_{MA(1)}\varepsilon_{t-1} + \beta_{MA(2)}\varepsilon_{t-2} + \ldots + \varepsilon_t$$

$$\sigma^2{}_t = \gamma_{ARCH(1)}\varepsilon^2_{t-1} + \gamma_{ARCH(2)}\varepsilon^2_{t-2} + \ldots$$

Model specifications with ARIMA terms of lags up to three were tested using the Aikaike Information Criterion. The estimated ARCH/ARMA model was then used to predict spot prices and variances for month $T_{n,}$ which establishes the cash price for the auctioned TCC. Table 1 provides the model specifications used in predicting contract month prices in the analysis.

Figure 1 illustrates the fit of the time series model for a sample TCC price series. The figure shows the observed congestion price difference (small circles) between the PoI and the PoW and the predicted spot price difference by month (small squares). As can be seen, the time series model well reflects the trends and volatility in NYISO monthly spot price differences.

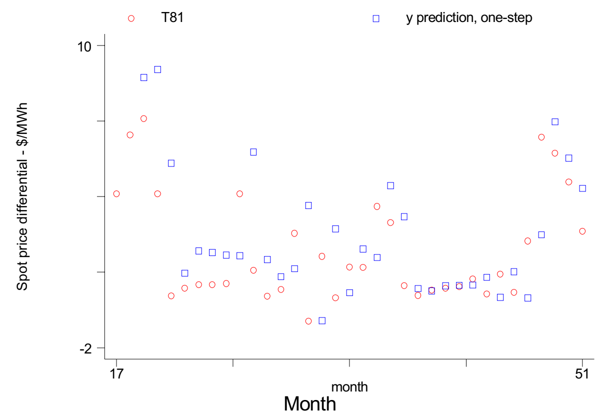

Figure 1. Example of time-series fit

Similar models were fit to the other TCC price series, using different model specifications as presented in Table 1 below.

Table 1. Model Specifications - ARCH/ARMA

TCC IDs	Differenced	AR Terms	MA Terms
T1-T5	1	-	MA(2)
T6-T12	1	-	MA(1)
T13-T15	1	AR(2)	MA(2)
T16-T18	1	AR(1 2)	MA(2)
T29-34	1	AR(1)	MA(1)
T54-T55	1	-	MA(1)
T56-T59	1	-	MA(1)
T60-T64	1	-	-
T75-T77	1	AR(1)	MA(1)
T78-T80	2	AR(3)	MA(1)
T81-T90	2	-	MA(1)

For each case an ARCH-ARMA model was found that provided a good fit to historical spot prices and volatilities. The model for each TCC was then used to predict the auction clearing price for the month in which that TCC was sold.

3.3. Estimation of second stage regression model

We postulated that TCC auction prices are a linear function of the predicted spot price and predicted variance.

To test that hypothesis, the following model was estimated:

$$AUC_{i\,n} = \alpha + \beta_1 predmean_{i\,n} + \beta_2 pred\,\mathrm{var}_{i\,n}$$

where $AUC_{i\,n}$ is the observed auction clearing price of TCC_i in the NYISO auction, $predmean_{i\,n}$ is the predicted mean spot price for the univariate ARCH or ARCH-ARMA equation, and $predvar_{i\,n}$ is the predicted variance, based on the same ARCH or ARCH-ARMA equation for the relevant price series and month *n*. Additional specifications using the linear coefficient in the square of the predicted variance were also tested, as was the contract month *n*.

4. Results

The ARCH-ARMA model appeared to provide a reasonable basis for projecting future spot price differences for contracts with at least 24 months of prior data. All of the contracts modeled had at least this amount of prior data available — no contracts from the early months of the TCC auctions were included in the dataset.

The results of the first stage analysis were then used to determine whether the clearing prices in the auction were consistent with the linear model described previously — i.e., was the clearing price a linear function of the predicted cash price mean and variance?

The estimated linear equation was:

$$AUC = 0.499\,predmean - 0.098\,pred\,\mathrm{var} + 0.395$$

The standard errors on *predmean*, *predvar* and the constant term were 0.138, 0.052 and 0.400 respectively. A *t*-test confirms that the coefficients on *predmean* and *predvar* are significant at the 10% level, with *predmean* having a *t* value of 3.61. The constant term was not significantly different from zero.

The coefficients on both *predmean* and *predvar* are significant and have the expected sign — the amount bid is positively correlated with the predicted mean return and negatively correlated with the predicted variance, as would be expected due to risk aversion. Note that the coefficient on *predmean* is only approximately one-half, suggesting that the TCC prices realized were only half of the expected spot value. Either bidders had difficulty in establishing efficient expectations of prices, or TCC purchasers were especially risk averse to a degree not captured in the linear model.

To test the latter possibility, a second linear model was estimated, with the auction price determined as a function of *predmean* and the square of the predicted variance (*predvarsq)*. This model has the form:

$$AUC_{i\,n} = \alpha + \beta_1 predmean_{i\,n} + \beta_2 pred\,\mathrm{var}\,sq_{i\,n}$$

The results of the estimation were:

$$AUC = 0.386\,predmean - 0.009\,pred\,\mathrm{var}\,sq + 0.31$$

with standard errors of 0.137, 0.004 and 0.323 on each of the three terms in order. All terms except the constant were significant at the 5% level. Under this specification, less than 39% of the predicted mean was captured in auction prices.

5. Conclusions

The hypothesis that prices in the NYISO TCC auction can be predicted using univariate ARCH-ARMA models based only on past monthly spot price differences available before the auction cannot be immediately rejected. The individual time series models predicted contract month conditional means and variances fairly well and appeared to capture the major features of spot congestion price differences in the NYISO day-ahead power market.

More importantly, this analysis has reinforced the evidence that pricing in the NYISO TCC auctions continues to be inefficient, with the TCC clearing prices representing less than half of their expected spot value, even after making allowances for risk aversion (using the predicted variance or its square as a measure of risk). Market participants may continue to find it difficult to develop accurate expectations of NYISO market prices, while the regulatory risks and transactions costs associated with TCC trading in New York, as well as their locationally idiosyncratic nature, may have stymied efficient secondary market trading in the instruments.

In further work, it should be possible to examine a significantly larger number of TCCs (up to the approximately 900 TCCs that have been traded to date in the NYISO monthly auctions), as well as longer-term TCCs. Furthermore, examining TCCs spanning locations at which forward markets for energy have some liquidity (e.g., NYISO zones A and J) and comparing the results for those TCCs to those spanning illiquid locations would help to discern the impact of forward energy market liquidity on the efficiency of the TCC market.

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