Energy Economics 46 (2014) 176–185

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneco

An econometric framework for evaluating the efficiency of a market for transmission congestion contracts

Timothy D. Mount [a,*], Jaeuk Ju [b]

[a] Charles H. Dyson School of Applied Economics and Management, Cornell University, United States
[b] Korea Information Society Development Institute, Republic of Korea

ARTICLE INFO

Article history:
Received 31 August 2010
Received in revised form 12 September 2014
Accepted 13 September 2014
Available online 30 September 2014

Jel classification:
Q4
C1
C3
C5
D4
D8

Keywords:
Electricity prices
Econometric models
TCC
Financial risk

ABSTRACT

The goals of this paper are to 1) simulate the ex-ante riskiness of purchasing a TCC, and 2) evaluate the efficiency of the TCC market in New York State to determine if there is evidence of under-pricing. Three VAR models are estimated using only market data available before the auction. This model is then used to simulate the daily payouts of a TCC for the following summer. A Monte Carlo procedure simulates the daily summer temperatures, the levels of quantity demanded and prices over the summer months. The main empirical result is that the market price paid for the most important TCC, in terms of volume, (the Hudson Valley to New York City) is higher than the mean of the simulated payouts even though the actual payout was higher than the market price. The market prices for the other two TCCs are lower than the means of the simulated payouts, and as a result, there is no consistent evidence of under-pricing in this analysis of the market for six-month TCCs in the summer of 2006.

1. Introduction

The electricity market in New York State was restructured in November, 1999, and by 2006, the number of nodes on the network had increased to more than 400. The electricity price at each node is called the nodal price and these prices are determined by the system operator in an auction based on the offers submitted by different generators. Nodal prices are highly volatile and price spikes can occur in load pockets,[1] like New York City, when the demand for electricity is high and transmission lines are congested. The congestion cost can be determined from the nodal price difference between two different nodes after accounting for losses. Since nodal prices and congestion costs are intrinsically uncertain, different kinds of financial instruments, such as transmission congestion contracts (TCCs), have been developed to hedge against the risk of price differences between areas. The theory of Financial Transmission Rights (FTR) has been discussed by Hogan (1992), Hogan (1997), Joskow (2000), Joskow (2005), Cai (2005) and Zhang (2009). Since the transmission corridor from the Hudson Valley to New York City is the most important transmission bottleneck in New York State, the efficiency of the market for this TCC has been of particular interest to policy makers. In the Transmission Congestion Contract Manual published by the New York Independent System Operator (NYISO) (NYISO, 2007), a TCC is defined as follows[2]:

> A TCC represents the right to collect, or the obligation to pay, the Day-Ahead Market (DAM) Congestion Rents associated with 1-Megawatt (MW) of transmission between a specified Point of Injection (POI) and specified Point of Withdrawal (POW). The DAM Congestion Rents are determined by the difference in the Congestion Component of the DAM, Locational Based Marginal Price (LBMP) at the POW of the TCC and the Congestion Component of the DAM LBMP at the POI of the TCC, for each hour of the effective period.

The objectives of this paper are to develop an analytical framework for 1) simulating the ex-ante riskiness of purchasing a TCC, and 2) evaluating the efficiency of the TCC market in New York State. This is accomplished by estimating an econometric model to simulate the stochastic behavior of nodal prices and derive the stochastic

* Corresponding author at: School B33 Warren Hall Cornell University Ithaca, NY 14850, United States.
E-mail addresses: tdm2@cornell.edu (T.D. Mount), jujaeuk@kisdi.re.kr (J. Ju).

[1] The area in which the electricity demand is higher than surrounding areas.

[2] p. 2-1, Transmission Congestion Contract Manual.

http://dx.doi.org/10.1016/j.eneco.2014.09.014

characteristics of the corresponding congestion costs for a chosen TCC and, in particular, the TCC for the link from the Hudson Valley to New York City. Through this process, simulated price differences are used as the basis for measuring the financial riskiness of congestion costs. The model predicts the prices in four different zones, A (West), G (the Hudson Valley), J (New York City) and K (Long Island). The basic specification for the model is that uncertainty about future temperatures is the main source of financial risk because it leads to uncertainty about future levels of quantity demand, and this, in turn, leads to uncertainty about future prices. In the econometric model, each price of electricity in a zone is a function of the corresponding level of quantity demand, the price of natural gas and a set of seasonal and daily variables, the quantity demanded in a zone is a function of the corresponding temperature and a set of seasonal and daily variables, and the temperature in a zone is a function of a set of seasonal variables.

Three multivariate time-series models (Vector Auto-Regressive (VAR)) were estimated using daily data from 2002 to 2005 for 1) the residuals from the model for daily temperature in different locations conditional on seasonal cycles, 2) the residuals from the model for the average daily quantities demanded in different zones conditional on heating degree days (HDD), cooling degree days (CDD), seasonal cycles and dummy variables for days of the week, and 3) the residuals from the model for the prices of electricity in different zones conditional on quantity demanded, a polynomial lag of past prices of natural gas at Henry Hub, seasonal cycles and dummy variables for days of the week. A separate Auto-Regressive Integrated Moving Average (ARIMA) model for the price of natural gas at Henry Hub was also estimated. The structure of this model captures relationships across locations while maintaining a recursive structure of the overall model. In other words, temperature is treated as an exogenous variable in a quantity demanded equation, and quantity demanded, and the price of natural gas are treated as exogenous variables in a price equation. Although the assumption of exogeneity of quantity demanded can be challenged, no solid evidence of simultaneity between price and quantity demanded was found for these data. This would probably not be true using more current data because quantity demanded response has become more important and more customers are now directly exposed to real-time prices. In addition, the use of daily data was considered to be a sensible level of aggregation because TCC payments cover every hour over a contract period, and using an hourly model would involve much greater complexity to capture the seasonal changes of daily quantity demanded profiles. Even with the simplifications of using a recursive structure and daily data, the estimation still posed computational challenges for the statistical package (SAS) such as eigenvalue computation failure, and each set of equations had to be estimated in two stages. However, the statistical properties of the final model are satisfactory and it explains over 90% of the variability for every dependent variable, and most importantly, it replicates price behavior well.

The estimated models were then used to simulate daily price differences between zones A–G, A–J, G–J and J–K for the summer of 2006. The sum of these price differences from May to October determines the earnings of a six-month strip for the corresponding TCC. Since the models were estimated using only information that was available before the auction to sell the TCCs, it is appropriate to use these models to simulate the ex-ante financial risk of purchasing a TCC in the auction. Ten thousand different realizations of the daily temperatures in different locations and the price of natural gas are simulated for May to October 2006 to represent a random sample of 10,000 summers. Each realization of the daily price of natural gas is paired with one realization of the three daily temperatures to simulate 10,000 daily quantities demanded and the corresponding daily prices of electricity in the four zones. These prices are then used to compute the daily price differences. The 10,000 payouts from holding a TCC for May to October 2006 are computed by scaling and aggregating the daily price differences. Finally, the average simulated TCC payout from holding a TCC is compared with the actual market clearing price for each TCC in the auction. If the auction price is found to be significantly lower than the average value, this would indicate evidence of under-pricing. The empirical analysis shows that there is no consistent evidence of under-pricing, and in particular, the auction price is higher than the average simulated price for the highest volume TCC from the Hudson Valley to New York City (zones G–J).

Many trials to model electricity prices or relevant transaction costs with other variables including seasonality are found in various previous literatures. Park et al. (2006) examined 11 U.S. electricity spot market prices using time series analysis. Then, Park et al. (2007) also developed bivariate three-regime threshold vector error correction models to examine seasonality in transaction cost and supply and demand between markets. They found that in the natural gas sector, dynamic threshold effects vary depending on season, geographical location and whether the market is an excess producing or consuming market. Mjelde and Bessler (2009) studied dynamic price information flows among U.S. electricity wholesale spot prices and the prices of their major sources. Market efficiency has been studied in many researches including Fama (1998).

2. The spatial structure of nodal prices in the New York electricity market

The electricity market in New York State has 11 zones: West (A), Genesee (B), Central (C), North (D), Mohawk Valley (E), Capital (F), Hudson Valley (G), Millwood (H), Dunwoodie (I), New York City (J), and Long Island (K). Real-time nodal price data are available on the NYISO website (www.nyiso.com), and the total number of nodes in New York State, including interstate transmission nodes to adjoining systems has increased consistently from 359 in 1999 to 453 in 2007. In Table B.1 the number of nodes by zone in New York State from 1999 to 2007 is shown.[3] In general, nodal prices are the lowest in the west of the state and get higher moving east and south, with the highest prices occurring in zones J and K.[4]

In Fig. 1 the annual mean hourly real-time prices for each node in 2001 and 2005 are shown. The 11 zones are listed in alphabetical order and the order of nodes is the same for each year using the ranked mean price within each zone in 2007. The plots also show the averages for the highest 10% of prices (average peak prices) and the averages for the lowest 10% of prices (average base prices) using the same nodal ordering as the mean prices. By comparing the plots for 2001 and 2005 in Fig. 1 it is shown that the spatial differences among the average peak prices were substantially larger in 2005 than in 2001, implying that congestion increased over time. In addition, the differences among average peak price within zone J were significantly higher in 2005 than they were in 2001. In 2001, the biggest price differences were between zone A and zones J and K, but in 2005, the biggest differences are within zone J even though there was no significant increase in the electricity quantity demanded in zone J (see Fig. 3). A possible explanation for this change is that modifications were made in how the nodal prices were computed by the NYISO. Since the spatial structure of the market is very complicated at the nodal, the analysis that follows is based on the average prices in zones A, G, J and K. These zones were chosen to capture the major sources of congestion on the network, and in particular, the congestion between the Hudson Valley (zone G) and New York City (zone J).

3. Econometric models for temperature, electricity quantity demanded, and electricity price

Since congestion costs can be calculated from the differences in electricity prices between zones, these costs can be derived directly from models of the prices of electricity in the four chosen zones if the spatial relationships among these prices are represented effectively. For this reason, three Vector Auto-Regressive (VAR) models based on the residuals from the regression models were chosen. The dependent variable

[3] 'U' is the group of nodes with an unidentified zone.

[4] These high prices are caused by congestion on the transmission network into New York City and Long Island.