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The impact of wind generation on the electricity spot-market price level and variance: The Texas experience

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ABSTRACT

The literature on renewable energy suggests that an increase in intermittent wind generation would reduce the spot electricity market price by displacing high fuel-cost marginal generation. Taking advantage of a large file of Texas-based 15-min data, we show that while rising wind generation does indeed tend to reduce the *level* of spot prices, it is also likely to enlarge the spot-price *variance*. The key policy implication is that increasing use of price risk management should accompany expanded deployment of wind generation.

1. Introduction

The existing literature on renewable energy suggests that an increase in intermittent wind generation offers two financial benefits. In the context of a competitive generation market, the benefit is a reduction in spot electricity prices due to the increase in wind generation displacing marginal generation with a high fuel cost (EWEA, 2009, 2010; Woo et al., this issue-a; Sensfuß et al., 2008). From the perspective of electricity consumers, this benefit can be large, since the price reduction would apply to all of the spot-market purchases made directly by themselves or on their behalf by a local distribution company.[1] In the context of an integrated utility, the benefit is that the increase in wind generation cuts the utility's natural-gas purchase cost and provides a hedge against the fuel-price risk (Bolinger et al., 2005; Berry, 2005). Such benefits, however, may come at the cost of an increase in the spot-price variance (Milstein and Tishler, this issue; Chao, this issue; Jacobsen and Zvingilaite, 2010; Green and Vasilakos, 2010).

There is extensive research on spot electricity price behavior and dynamics (e.g. Woo et al., this issue-b and the references therein). There is, however, only limited evidence based on actual market-price data enabling one to study the impact of rising wind generation on spot electricity prices. Such a study is particularly salient at this time because wind generation is the primary and abundant source of renewable energy now being promoted by government policies in many parts of the world, including North America, Europe and China (Woo et al., this issue-a; Lu et al., 2009; Hoogwijk et al., 2004). If rising wind generation has a large impact on the variance of spot-market prices, then expansion of wind-generation capacity should also be accompanied by an increasing use of electricity price risk-management instruments and techniques (e.g., Deng and Oren, 2006; Eydeland and Wolyniec, 2003).

The purpose of this paper is to conduct that salient study by estimating the parameters of a partial-adjustment linear regression model of spot electricity (i.e., balancing energy) prices in Texas. The estimated model enables a direct prediction of the effect of an increase in wind generation on spot electricity price level and variance, which provides important information useful for making electricity procurement and risk- management decisions (e.g., Woo et al., 2004a, 2004b, 2006).

The Texas experience is important because of the state's large and rising wind generation, and because Texas is the largest electricity-consuming state in the nation. And to the best of our knowledge, there is only one econometric analysis of high-frequency market-price data, such as we employ, directed at the impact of wind generation on spot electricity prices.[2] Nicholson et al. (2010, p. 19) find that a 100-MWH increase in wind generation in Texas may reduce the four-zone Electricity Reliability Council of Texas (ERCOT) 15-min balancing-energy

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[1] The spot price decline, however, could discourage investment in thermal generation (Traber and Kemfert, 2011; Steggals et al., 2011), which might in turn cause spot price spikes during hours of low wind generation (Milstein and Tishler, this issue).

[2] This is based on our literature search done at scholar.google.com on January 22 2011, using the following keywords: "spot electricity", "price volatility", and "wind energy".

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market price by \$0.71/MWH in the Houston zone, \$0.07/MWH in the North zone, \$0.57/MWH in the South zone, and \$1.18/MWH in the West zone where nearly all wind generation resides. What is not known is what the same 100-MWH may do to the ERCOT's zonal price variance.

We take advantage of a unique and rich ERCOT data base fully described in Woo et al. (this issue-b). The data comprise 15-min electricity prices in each of the four ERCOT zones, observed over the 41-month period of January 2007 through May 2010. Seldom available elsewhere, this data base has four distinct features that aid our detection of the price effects of wind generation (Sioshansi and Hurlbut, 2010; Woo et al., this issue-b; Zarnikau, this issue):

- The installed capacity of wind generation grew during the 11-year period of 1999–2009 from less than 500 to over 7500 MW, and now accounts for about 10% of ERCOT's total generation capacity of approximately 80,000 MW. When combined with the intermittence of wind generation, this feature leads to widely dispersed levels of wind-energy output, a requisite for statistically precise detection of its effect on market prices.
- Wind generators have a tax-credit incentive to make very low, even negative supply bids, so as to be treated as must-run and dispatched by the ERCOT independent system operator. This feature helps unmask the price effects of wind generation, not confounded by the generators' bidding behaviors.
- ERCOT's marginal generation in the non-West zones is likely to be natural-gas fired and dispatchable, offering ample opportunity for spot-price reductions through its displacement by wind generation. If the marginal generation were must-run and non-dispatchable (e.g., nuclear or run-of-river hydro), wind generation might not have a detectable price effect because the marginal supply bid and the resulting market-clearing price would have been close to zero.
- ERCOT's 15-min zonal loads are price-insensitive and therefore can be used as exogenous variables to delineate market price movements due to fluctuating demands (ERCOT, 2004). This feature leads us to suggest that a detected price effect of wind generation could not have been biased by the possible price response of zonal loads.

As will be shown, the ERCOT data base enables us to confirm that while rising wind generation tends to reduce the *level* of spot prices, it also tends to enlarge the spot-price *variance*. The key policy implication is that increasing effort in price risk management should accompany expanded deployment of wind generation.

2. Model

The focus of our attention is the 15-min balancing-energy market price within each of the four ERCOT zonal markets. Suppressing a subscript to delineate the individual zones, let Y_t denote that zonal market price in a particular zone during time interval t. The price Y_t, which is the dependent variable in a linear regression model with partial adjustment, is driven by a set of seven numeric metric variables, denoted x_{rt} ($r=1,\ldots,7$), the lagged price, Y_{t-1}, which gives the model its partial-adjustment character, and a set of three time-dependent binary indicators that account for month of the year (M_{it}), day of the week (W_{jt}), and hour of the day (H_{kt}), with $i=1,\ldots,11$; $j=1,\ldots,6$; $k=1,\ldots,23$, respectively. Letting ε_t denote a normally distributed disturbance term, the model is written as

$$Y_t=\alpha+\Sigma_r\beta_r x_{rt}+\gamma Y_{t-1}+\Sigma_i\mu_i M_{it}+\Sigma_j\omega_j W_{jt}+\Sigma_k\eta_k H_{kt}+\varepsilon_t. \quad (1)$$

In Eq. (1), ε_t is assumed to follow a stationary AR(1) process: $\varepsilon_t=\rho\varepsilon_{t-1}+\upsilon_t$, with $|\rho|<1$ and υ_t=white noise (Kmenta, 1986, pp. 528–536). The coefficients to be estimated are α, $\{\beta_r\}$, γ, $\{\mu_i\}$, $\{\omega_j\}$, $\{\eta_k\}$ and ρ.

Four sets of coefficients are estimated, one for each ERCOT zone, based on samples of approximately 116,000 observations. As will be seen, our AR(1) assumption is validated for all four regressions. The estimated model will ultimately be used to explore the impact of changes in wind generation on the levels and variances of the zonal market prices.

The seven metric variables are as follows:

- x_{1t} is the 15-min wind generation of the ERCOT system, which is largely at the mercy of random wind conditions. We hypothesize that rising wind generation reduces market price, which translates into the hypothesis: $\beta_1<0$.
- x_{2t} is the 15-min MWh nuclear generation in the ERCOT system. We do not use the 15-min data on dispatchable generation (i.e., hydro, coal, and natural gas), because they are endogenous as a result of ERCOT's least-cost dispatch decisions (ERCOT, 2004). Nuclear generation is baseload and non-dispatchable. Reducing nuclear output due to maintenance, repair or refuel is expected to raise the market price. This translates into the hypothesis: $\beta_2<0$.
- x_{3t} is the daily Henry Hub natural-gas price. Because of Texas's vast thermal-generation fleet, we use the exogenous Henry Hub price, which is almost perfectly correlated with the Houston Ship Channel price (R=0.99), to quantify what we hypothesize to be the positive price effect of the marginal fuel (natural gas) on the electricity market price. This translates into the hypothesis: $\beta_3>0$.
- x_{4t}, x_{5t}, x_{6t}, x_{7t} are 15-min exogenous MWh loads in ERCOT's Houston zone, North zone, South zone, and West zone, respectively. Rising loads tend to raise market prices; hence, (β_4, …, β_7) are hypothesized to be positive.
- An increase in the lagged price likely raises the current price, with its effect dampening over time (Woo et al., 2007). This translates into the hypothesis: $0<\gamma<1$. The size of γ measures the speed of adjustment such that $1/(1-\gamma)$ is the number of 15-min intervals required to achieve the equilibrium state of $Y_t=Y_{t-1}$, implying $\beta\equiv\beta_1/(1-\gamma)$ is the "full" price effect of wind generation.

The binary indicators aim to capture the spot price's residual time-dependence that may exist *after* controlling for the influence of the aforementioned metric variables. They are: (a) $M_{it}=1$ for $i=1$ (January), …, 11 (November), and is zero otherwise; (b) $W_{jt}=1$ for $j=1$ (Sunday),…, 6 (Friday), and is zero otherwise; and (c) $H_{kt}=1$ for $k=1$ (an hour ending at 1:00), …, 23 (an hour ending at 23:00), and is zero otherwise.

3. Data

Table 1 presents the descriptive statistics for the approximately 116,000 observations used in our regression analysis. It shows that 15-min zonal prices are highly volatile, have large spikes (e.g., up to \$4500/MWH for the North zone), and can be negative (e.g., -\$1536/MWH for the Houston zone). Reflecting capacity growth and output intermittency, the 15-min wind-generation output has a range of 0–1703 MWH, with an average of 444 MWH. The 15-min nuclear generation tends to be close to full capacity, as evidenced by the average