The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest

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***Abstract*—Extant literature documents that wind generation can reduce wholesale electricity market prices by displacing conventional generation. But how large is the wholesale price effect of wind generation in an electricity market dominated by hydroelectric generation? We explore this question by analyzing the impact of wind generation on wholesale electricity prices in the Pacific Northwest region of the United States. This hydro-rich system tends to be energy-limited, rather than capacity-constrained, with its marginal generation during the hydro runoff season often a hydro unit, instead of a natural-gas-fired unit. We find that increased wind generation reduces wholesale market prices by a small, but statistically-significant, amount. While a hydro-rich system can integrate wind generation at a lower cost than a thermal-dominated region, the direct economic benefits to end-users from greater investment in wind power may be negligible.**

***Index Terms*—Electricity markets, electricity prices, power-system economics, regression analysis, sustainable development, wind energy.**

I. Introduction

EXTANT literature documents that increased wind generation can have a large and statistically-significant impact on prices in a wholesale electricity market dominated by thermal generation [1]–[4]. The price reduction results from wind generation's displacement of costly marginal generation units now often fueled by natural gas and mitigation of capacity shortages [1]. In the Electric Reliability Council of Texas (ERCOT) market, where fossil fuels dominate the generation mix and natural gas is commonly the marginal fuel, wind generation can significantly lower wholesale prices. In fact, wind generation occasionally leads to negative prices [5]. While this price reduction can offer substantial benefits to electricity end-users when it applies to their total usage, it has led to concerns as to whether the increasing availability of wind power will dampen the incentives to construct new thermal generating capacity in an "energy-only" market [6]. Similar concerns over wind generation being a disincentive for the construction of additional thermal generation have been raised in Germany [7].

Compared to a system dominated by thermal power, a hydro-rich system such as the Pacific Northwest region in the United States tends to be energy-limited, rather than capacity-constrained, with its marginal generation during the spring runoff season of April through June often a hydro unit, rather than a natural-gas-fired unit. The hydro-generation source meets roughly two-thirds of the electricity needs in this winter-peaking market, which serves the states of Washington, Oregon, Idaho, and Utah, as well as portions of Montana, Wyoming, and California.

As in many other regions of North America, the generation mix in this region is changing with the construction of new wind farms. Oregon ranks sixth among the fifty states in wind-generation capacity, providing over 8% of the state's electricity needs through 2513 MW of wind capacity [8]. Washington increased its wind-generation capacity from virtually nothing in 2000 to 2573 MW by the end of 2011, and it now provides over 5% of the total electricity generated in that state [9]. Most of the existing and proposed wind-generation projects in these two states are to the east of the 1780-MW Dalles Dam on the Columbia River, where inland heating draws cool air from the coastal region through the Columbia River Gorge.[1]

The federal Bonneville Power Administration (BPA) has been active in accommodating wind-generation development in the Pacific Northwest,[2] and transmission congestion may only occur during the spring runoff season of a particularly wet hydro year. This mitigates concerns of transmission congestion and its ensuing impact on the wholesale market prices at the Mid-C hub described in Section II below.

Wind generation in this region is expected to continue to grow. Washington, Oregon, and Montana have enacted Renewable Portfolio Standards (RPS), requiring power suppliers to obtain an increasing percentage of their generation requirements from new or recently-developed renewable energy sources [10], which are made possible by the considerable potential in this region [11].

As wind power increases its share of the generation mix, how will wholesale prices be affected in a hydro-rich electricity

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[1]The 2012 map of these projects is available at: http://transmission.bpa.gov/planproj/wind/documents/BPA_wind_map_2012.pdf

[2]BPA's response to a huge influx of wind power is available at: http://www.bpa.gov/news/pubs/FactSheets/fs200811-BPA responds to influx of wind power.pdf

market? This is a question of interest to 1) consumers, whose retail electricity prices are affected by wholesale prices, 2) policymakers, who seek to understand the impacts of renewable energy development efforts upon energy prices and reliability, 3) market participants, who engage in power trading and hedging, 4) power-plant owners, seeking to forecast their revenues from sales of generation into wholesale markets, and 5) generation-project developers seeking to determine the profitability of investments in new generating capacity.

We address this question by analyzing the impact of wind generation on the Pacific Northwest's wholesale electricity prices. We find that increased wind generation reduces wholesale prices by a small, but statistically-significant, amount. The policy implication is that while a hydro-rich system can integrate wind generation at a lower cost than a thermal-dominated region, end-users may also see less direct economic benefit from greater investment in wind power.

In related avenues of research, optimization models have been developed to simulate the impact of wind generation on electricity prices, thus providing theoretical insights [12], [13]. Jónsson, Pinson, and Madsen analyzed price formation in the Western Danish Price Area, the world's leading region in wind-power dependence [14]. Findings from their study provide a useful benchmark for our analysis, since the Nordic market, of which the Western Danish Price Area is a part, is similarly heavily dependent upon hydroelectric power, and prices are established in a day-ahead market. Singh and Erlich explored how alternative market designs affect the compensation to wind generators in a competitive wholesale market [15]. Optimal strategies for offering wind generation into a competitive wholesale market also have been devised [16]–[21], and the benefits of accurate forecasts of wind generation or value of information have been extensively studied [22]. The impact of wind-power control strategies, penetration level and location on prices is investigated in [23]. Hydro power has also been considered to balance the uncertainty and variability of wind power in combined stochastic optimization settings in [24]–[26]. In contrast to measuring how wind power affects market prices, the impact of real-time pricing on wind-power utilization has been studied in [27].

The patterns and determinants of day-ahead wholesale electricity prices in the Pacific Northwest have previously been studied [28], [29]. The relationship between wind generation and wholesale prices, however, was not modeled in these earlier analyses. This paper expands these studies to better analyze the relationship between wind generation and wholesale electricity prices in the Pacific Northwest.

The paper is organized as follows. Section II describes the source of our price data. Section III introduces the regression model that is instrumental in our analysis. Section IV develops the estimation procedure, Section V presents the results, and Section VI concludes.

II. Mid-C Hub

Physically located at several substations along the Columbia River in the state of Washington, the Mid-Columbia (Mid-C) hub is an intersection point for numerous regional transmission systems, including the Federal Columbia River Transmission System (FCRTS) operated by BPA. Many regional utilities such as Puget Sound Energy and Avista Corporation are directly connected to Mid-C, while the FCRTS provides relatively unconstrained access to Mid-C for other market participants. In short, wholesale market trading and its ensuing prices at Mid-C are largely free from transmission constraints and congestions.

Mid-C is an important wholesale spot-electricity market in the Pacific Northwest region of the U.S. Several large hydroelectric dams are housed within this region, including Grand Coulee (6089 MW) and Dalles (1780 MW). The Dalles Dam on the Washington-Oregon border is the most closely watched indicator of the Federal Columbia River Power System's energy potential, and the subject of forecasts published by the Northwest River Forecast Center during the winter. Overall, hydroelectric projects comprise 60% of the region's generating capacity [28]. Mid-C is also very close to most of the region's wind energy facilities, and the FCRTS provides ready access to Mid-C for wind energy producers.

Unlike a wholesale market with a centralized power exchange and nodal price determination (e.g., ERCOT), the Pacific Northwest has bilateral trading among participants primarily through telephone calls. Prices are established on a day-ahead basis and reported in various trade publications. Standard products defined by the Western Systems Power Pool (WSPP) specify delivery to the physical Mid-C location, and are traded among parties with physical transmission rights that allow access to and from Mid-C.

The Mid-C hub prices generally move with prices in the hubs at the California-Oregon border (COB) and California's NP15 and SP15 delivery points, because the Pacific Northwest is part of the vast Western Electricity Coordinating Council (WECC).[3] To be sure, transmission system limitations sometimes prevent power from flowing to California, particularly during times of unavoidable high hydro production (e.g., the spring runoff), leading to separation between Mid-C and California prices. Such transmission congestions, however, are between the Pacific Northwest and California, not within the Pacific Northwest.

Hydroelectric production prominently impacts prices during on-peak hours, defined in the WSPP Agreement as being from 6 a.m. to 10 p.m., Monday through Saturday, excluding holidays. During these periods, electricity demand is relatively high and the fast-ramping capability of hydro facilities can effectively satisfy fluctuating demands. During off-peak hours, hydro systems are ramped down, enabling reservoirs to replenish for the following day's on-peak production.

Wholesale prices at the Mid-C hub are weather-sensitive and seasonal. River flows are highest during the spring runoff and when water is released for salmon spawning. Extreme temperatures in the Pacific Northwest increase aggregate demand for electricity, resulting in high prices. Below-normal precipitation

[3]Specifically, the Pacific Northwest grid is interconnected with utility systems in California, New Mexico, Arizona, far western Texas, and a portion of Mexico to the south and two Canadian provinces to the north. Interconnections enable surplus hydro power to flow south in the summer to meet air conditioning needs. Surplus thermal generation may flow north in the winter months from the Southwest U.S. states to meet heating loads in the Pacific Northwest.

can severely impede hydro generation, prompting the dispatch of natural-gas-fired generating units with higher operating costs, subsequently raising the electricity spot-market price. Finally, prices exhibit seasonality for reasons beyond the Pacific Northwest weather, as they are also driven by the seasonal market conditions in California and its neighboring states.

III. MODEL

Our model of day-ahead Mid-C prices is a variation on a theme by [30] that focused on the four ERCOT zonal markets of Texas. The variation is orchestrated to take advantage of the unique characteristics of the daily demand for, and supply of, electricity in the Pacific Northwest. Specifically, the model recognizes the fact that, as has been shown in [28], [29] and as one would anticipate, daily Mid-C prices are sensitive to that day's weather conditions. On the one hand, the demand for electricity is weather-dependent due to the increased reliance on electricity-generated heat in cold weather and electricity-generated air conditioning in hot weather. On the other hand, the weather-dependent flows at the Dalles hydroelectric dam impact prices, because hydro generation comprises more than half of the generation capacity in the Northwest Power Pool, and the flows can be sensitive to precipitation in the area, depending upon the need for replenishment. As will be seen below, these two stochastic weather-driven factors contribute to the large price variations observed in the Pacific Northwest, reflecting the empirical reality that wholesale electricity prices are more volatile than those in other energy markets such as coal, oil and natural gas.

While natural-gas-fired generation contributes less to the total market output in the Pacific Northwest than in Texas, it is an important component during months outside the spring runoff season of April through June. Hence, natural-gas prices can impact electricity prices, with thermal generation whose cost depends upon the price of natural gas having a supply-side influence. Like the Texas market, the Pacific Northwest market has non-dispatchable nuclear generation, whose output variations may also have an impact on the market prices.

But while Texas is the national leader in both electricity consumption and wind generation, which primarily takes place in the western part of the state and whose implications for electricity prices and thermal generation vary from zone to zone, the BPA exports the majority of its wind power as part of its surplus power sale. Thus, we anticipate that the effect of wind generation on prices in the Pacific Northwest might well be less than is the case for Texas. That, however, is an informed conjecture that merits empirical verification.

Our investigation's focus is an empirical examination of the effect of wind generation on the Mid-C day-ahead price. This focus motivates us to use a transparent and time-tested regression specification, as in [28] and [30].

Albeit deceptively simple, our regression specification should be judged by its performance in identifying and quantifying the price-reduction effect of wind generation in the presence of noisy and volatile wholesale-price data. As will be seen below, our specification yields pointed empirical findings amenable to meaningful interpretations that are consistent with economic and engineering intuition. This validates the usefulness of our approach for such users of wholesale-price information as the market participants and policy makers that may not be familiar with, and therefore may be skeptical of, highly complicated and somewhat obtuse techniques.

Specifically, then, let y_{tdmj} denote the 6:00 to 22:00 on-peak ($j = 1$) and the other-hours off-peak ($j = 2$) electricity price ($/MWH), respectively, for an observation day t ($t = 1, \ldots, 1992$) that falls on the day-of-the-week d ($d = 1$ (Sunday)$, \ldots, 7$ (Saturday)) in the month m ($m = 1$ (January)$, \ldots, 12$ (December)) from January 1, 2007 through June 30, 2012. That price is the dependent variable in a linear partial-adjustment AR(1) model whose independent variables comprise 17 binary dummy independent variables and six metric variables, in addition to the lagged-by-a-day price, $y_{(tdmj)-1}$, that gives the model its partial-adjustment characteristic. With any minor risk of confusion amply compensated for by reading clarity, we henceforth suppress all but the mandatory subscripts.

Six of the seven binary dummy variables that delineate the days of the week are introduced into the regression: D_2 is equal to unity when the day d is a Monday, and is zero otherwise, through D_7 is equal to unity when the day d is a Saturday, and is zero otherwise; by default, we exclude a comparable dummy variable, D_1, to single out Sundays. Similarly, 11 binary dummy variables identify the month, m: M_1 is equal to unity when the day-t observation occurs in the month of January, and is zero otherwise, through M_{11} when observation t occurs in November, and is zero otherwise. Again, by default we do not include a comparable dummy variable, M_{12}, for December.

We specify two types of weather-dependent electricity usage. In the first case, energy users respond to the cool-weather months of October through April through increased heating, the impetus for which is measured by $x_H = \max$ (65° F—daily minimum temperature, 0), or the heating degree-day. In the second case, energy users respond to the warm-weather cooling degree-days of May through September, which is measured by $x_C = \max$ (daily maximum temperature—65° F, 0), or the cooling degree-day. In both cases, Portland, Oregon temperature defines the degree-day measure.

The widely-available daily natural-gas price at the Henry Hub in Southern Louisiana, measured in $/MMBTU, is used to proxy natural-gas prices in the Pacific Northwest, denoted x_G, in light of the well-documented high spot-price correlation with other natural-gas spot markets in North America, including the local markets in the Pacific Northwest [31], [32].

The BPA sells its nuclear-generated power in Western spot markets, including the Pacific Northwest and California. The average of 5-min MW generated on observation day t is denoted x_N. Hydro flow at the Dalles Dam on the Washington-Oregon border, x_F, is measured by daily Columbia River flow in thousands of cubic feet per second.

Finally, and at the heart of the paper, x_W denotes the daily BPA average of 5-min wind generation in MW. This daily average MW reflects actual generation on the delivery day, even though the applicable price is established in the prior trading day. We use the actual MW on the delivery day for two reasons. First and foremost, we do not have each trader's own wind-

TABLE I
DESCRIPTIVE STATISTICS FOR THE SAMPLE PERIOD OF JANUARY 1, 2006 TO JUNE 6, 2012

Variable	Mean	Standard deviation	Minimum	Maximum
Daily Mid-C daytime price ($/MWH): 06:00 – 22:00	40.90	19.57	-2.0	197.4
Daily Mid-C nighttime price ($/MWH): other hours	31.80	19.41	-7.0	94.3
Portland cooling degree days (CDD)	1.35	2.89	0	23.8
Portland heating degree days (HDD)	13.48	9.34	0	43.8
Daily Henry Hub natural-gas price ($/MMBTU)	5.34	2.35	1.8	13.3
Daily Dalles Dam discharge rate (000 cubic feet/second)	183.13	92.56	63.9	528.7
Daily average of 5-minute MW of BPA's nuclear plant	913.59	433.66	0	1150.0
Daily average of 5-minute MW of BPA's wind generation	684.41	684.27	0	3817.0

Note: The local (Stanfield) and Henry Hub natural gas prices are highly correlated (r = 0.99)

TABLE II
PHILLIPS-PERRON UNIT-ROOT TEST STATISTICS BY TYPE

	Single mean		Trend	
Variable	*Tau*	*p*-value	*Tau*	*p*-value
Daily Mid-C daytime price ($/MWH): 06:00 – 22:00	-7.76	0.001	-12.50	0.001
Daily Mid-C nighttime price ($/MWH): other hours	-3.85	0.003	-5.18	0.001
Portland cooling degree days (CDD)	-12.72	0.001	-12.75	0.001
Portland heating degree days (HDD)	-6.27	0.001	-6.27	0.001
Daily Henry Hub natural-gas price ($/MMBTU)	-1.18	0.685	-2.53	0.312
Daily Dalles Dam discharge rate (000 cubic feet/second)	-3.48	0.01	-3.65	0.027
Daily average of 5-minute MW of BPA's nuclear plant	-6.11	0.001	-6.18	0.001
Daily average of 5-minute MW of BPA's wind generation	-27.68	0.001	-30.88	0.001

Note: The number of lags is eight, as automatically chosen by PROC AUTOREG in SAS.

generation forecast when negotiating his/her bilateral trades. Second, the market price can only reflect a consensus wind-generation forecast. To the extent that this forecast is highly correlated with the actual MW, we can use the actual MW as an instrument for the unobservable market consensus forecast. To be sure, the actual and forecast MWs differ, leading to a forecast error that may be correlated with the regression's error term and the problem of estimation bias. As a result, we perform additional analysis to test how the wind generation's price effect may change under alternative specifications for x_W.

Accurate day-ahead forecasts of the temperature, Henry Hub prices, nuclear generation, and the Dalles flow are readily available to Mid-C traders. The same, however, cannot be said for wind generation. Nonetheless, it is not unreasonable to assume that *on average* their forecasts will approximate "tomorrow's" wind-generated output and that their forecasts are highly correlated with the actual values. We therefore use the actual wind output to proxy the day-t-ahead forecast for wind generation, although we explore an alternative approach later in this paper.

Table I provides the descriptive statistics for our data. It shows that Mid-C prices are highly dispersed and can at times be negative. The CDD and HDD data suggest that the Pacific Northwest has relatively mild summer weather and cold winter weather. When available, nuclear generation operates at its full capacity of 1150 MW. Finally, wind generation fluctuates widely, with a range of 0 to 3187 MW that is far in excess of its mean of 684 MW.

Letting ε_t denote a random-error term with the usual normality properties, we initially obtain the ordinary-least-squares (OLS) estimates of parameters β_k $(k = 0, \ldots, 24)$ of the following equation:

$$y_t = \beta_0 + \beta_1 x_H + \beta_2 x_C + \beta_3 x_G + \beta_4 x_N + \beta_5 x_F + \beta_6 x_W + \beta_7 y_{t-1} + (\boldsymbol{DM})\boldsymbol{\beta} + \varepsilon_t \quad (1)$$

where $(\boldsymbol{DM})$ is a row vector comprising the day-of-the-week and month-of-the-year dummy variables that serve as controls, and $\boldsymbol{\beta}$ is a column vector of their 17 regression coefficients.

Although it could be argued that a double-log format would more appropriately model price behavior, the presence of negative prices prevents this, at least for the off-peak period when an abundance of wind and nuclear generation impels wind generators to pay buyers to use their energy to get the production tax credits. To allow for direct comparison of the parameter estimates for peak versus off-peak prices, we therefore model both in a linear format.

IV. ESTIMATION PROCEDURE

We initially tested both electricity-price series and the six independent variables for stationarity via the Phillips-Perron

TABLE III
MAXIMUM LIKELIHOOD ESTIMATION RESULTS FOR MID-C PRICE REGRESSIONS WITH PARTIAL ADJUSTMENT AND AR(1) ERRORS

Variable: coefficient	Daily Mid-C daytime price ($/MWH): 06:00 – 22:00			Daily Mid-C nighttime price ($/MWH): other hours		
	Estimate	Standard error	p-value	Estimate	Standard error	p-value
Total R^2	0.892	NA	NA	0.972	NA	NA
Akaike Information Criterion (AIC)	13046.2	NA	NA	10332.0	NA	NA
Mean squared error: MSE	41.87	NA	NA	10.64	NA	NA
Root mean squared error: RMSE	6.47	NA	NA	3.26	NA	NA
Portland cooling degree days (CDD): β_1	0.329	0.0605	<.0001	0.125	0.0393	0.0015
Portland heating degree days (HDD): β_2	0.166	0.0285	<.0001	0.109	0.0189	<.0001
Daily Henry Hub natural-gas price ($/MMBTU): β_3	0.902	0.0872	<.0001	0.397	0.0546	<.0001
Daily Dalles Dam discharge rate (000 cubic feet/second): β_4	-0.0187	0.00249	<.0001	-0.0151	0.00201	<.0001
Daily average of 5-minute MW of BPA's nuclear plant: β_5	-0.00102	0.00033	0.0022	-0.00085	0.00024	0.0003
Daily average of 5-minute MW of BPA's wind generation: β_6	-0.00096	0.00022	<.0001	-0.00072	0.00013	<.0001
Lagged daily price ($/MWH): γ	0.830	0.0123	<.0001	0.905	0.00893	<.0001
AR(1) parameter: ρ	-0.298	0.0233	<.0001	0.096	0.0242	<.0001

Note: For brevity, this table does not report the coefficient estimates for the intercept and the binary indicators that indicate statistically-significant time-dependence of the daily market prices ($\alpha \le 0.01$). "NA" denotes "not applicable".

TABLE IV
MAXIMUM LIKELIHOOD ESTIMATION RESULTS FOR THE MID-C PRICE REGRESSIONS WITH AR(1) ERRORS

Variable: coefficient	Daily Mid-C daytime price ($/MWH): 06:00 – 22:00			Daily Mid-C nighttime price ($/MWH): other hours		
	Estimate	Standard error	p-value	Estimate	Standard error	p-value
Total R^2	0.882	NA	NA	0.971	NA	NA
Akaike Information Criterion (AIC)	13238.9	NA	NA	10407.8	NA	NA
Mean squared error: MSE	45.98	NA	NA	11.00	NA	NA
Root mean squared error: RMSE	6.78	NA	NA	3.32	NA	NA
Portland cooling degree days (CDD): β_1	0.563	0.1042	<.0001	0.137	0.0479	0.0045
Portland heating degree days (HDD): β_2	0.121	0.0523	0.0209	0.052	0.0248	0.0383
Daily Henry Hub natural-gas price ($/MMBTU): β_3	5.49	0.279	<.0001	2.82	0.4394	<.0001
Daily Dalles Dam discharge rate (000 cubic feet/second): β_4	-0.0615	0.00735	<.0001	-0.0199	0.00424	<.0001
Daily average of 5-minute MW of BPA's nuclear plant: β_5	0.00006	0.00113	0.9547	0.00009	0.00063	0.8899
Daily average of 5-minute MW of BPA's wind generation: β_6	-0.00146	0.00027	<.0001	-0.00078	0.00012	<.0001
AR(1) parameter: ρ	0.770	0.0146	<.0001	0.977	0.0050	<.0001

Note: For brevity, this table does not report the coefficient estimates for the intercept and binary indicators that indicate statistically-significant time-dependence of the daily market prices ($\alpha \le 0.01$)

unit-root test with both a single mean and a trend, using an eight-lag structure. As seen in Table II, save for the natural-gas price, *all* variables, and most particularly and critically the two electricity-price variables, rejected the unit-root hypothesis, in all but two cases at p-values of $p = 0.001$; in the other two cases, the hypothesis is rejected at $p < 0.03$. This obviates any concerns we might have harbored as to a spurious-regression problem.

We obtained OLS estimates for both variants of (1) and subjected the residuals to the Durbin h test for serial correlation, which is the appropriate test for serially correlated errors when lagged values of the dependent variable are included as independent variables. Since in both cases we reject the hypothesis of uncorrelated errors, we estimated the equations anew, obtaining maximum-likelihood estimates assuming an AR(1) random-error process whose results are shown in Table III. The estimated intercepts and parameters for the 17 control variables are not shown, as they are of little interest in the present context. We then repeated the procedure for both price series, but with the lagged price omitted as an independent variable. Those estimates, with the previous caveat still in play, are shown in Table IV.

V. Results

Before exploring the wind generation's effect on Mid-C prices, we use Table III to assess if the daytime and nighttime regressions are reasonable representations of the price-data-generation process. Estimated using PROC AUTOREG in SAS, both regressions fit the data quite well ($R^2 \geq 0.9$). The statistically significant ($\alpha = 0.01$) coefficient estimates confirm our expectation that the daily Mid-C prices rise when: 1) the Portland CDD and HDD increase; 2) the natural-gas price increases; 3) the Dalles Dam discharge declines; 4) the BPA's nuclear plant's output falls; and 5) the BPA's wind generation declines. The coefficient estimates for the lagged price and the AR(1) parameter estimates suggest that the daily Mid-C prices are driven by yesterday's prices and random shocks. Taken together, these findings suggest that the two regressions in Table III are eminently reasonable representations of the price-data-generation process that allow us to confidently assess the impact of wind generation on that process.

A. Price Effect of Wind Generation

Based on Table III, the short-run daytime price reduction yielded by a 100-MW increase in the average wind generation output is \$0.096/MWH ($= -0.00096 * 100$), which is at the low end of the range of \$0.097 to 0.38/MWH reduction found for ERCOT [30].[4] The long-run price effect is \$0.565/MWH [$= 0.096/(1 - 0.83)$], which is within the range of \$0.34 to \$1.10/MWH found for ERCOT. These findings suggest that the price-reduction effect of wind generation in the Pacific Northwest is similar to the effects found for ERCOT's Houston, North and South zones, which have little wind generation and interzonal transmission congestion. It is, however, smaller than the effect in ERCOT's West zone that houses most of Texas' wind-generation capacity and has limited transmission for exporting wind energy to the other three zones. These findings are quite plausible, since natural gas is the day-time marginal generation fuel under high system-load conditions in both the Pacific Northwest and ERCOT.[5]

Based on Table IV, which reports the price regressions without the lagged price variable, the daytime price reduction yielded by a 100-MW increase in the average wind-generation output is \$0.146/MWH ($= -0.00146 * 100$), thus confirming the inferences that we have drawn from Table III.

Our findings differ from those obtained for Denmark which is highly dependent upon wind power and interconnections to hydroelectric generation resources in Norway and Sweden. The histograms provided by Jónsson, Pinson and Madsen [14] suggest that a 11%–20% penetration of wind generation in the Western Danish Price Area, would lead to a 10% reduction in the market price, which is much higher than our findings for the Pacific Northwest. Similarly, Munksgaard and Morthorst [33] display evidence of very large price movements in Danish markets, resulting from changes in wind-generation levels.

We attribute the difference in findings to two factors. First, the Pacific Northwest is a much larger market than West Denmark. A geographically large region in western North America, the Pacific Northwest is bounded by California to the south, the Pacific Ocean to the west and the Rocky Mountains to the east. It had a peak capacity of over 43 000 MW in 2011, or about seven times Denmark's total peak load in 2010. Moreover, the Pacific Northwest is tied to its southern neighbor California, whose vast power imports tend to dilute the price-reduction effect of wind generation in the north. In contrast, West Denmark is a small market that is susceptible to large price movements and volatility. Second, the Pacific Northwest does not have the significant transmission constraints that might fragment the aggregate market. This is not the case for West Denmark where frequently-binding transmission constraints lead to the establishment of submarkets within the Nordic market [34], similar to what has been observed in the ERCOT's West zone.

B. Final Checks

The regression results in Tables III and IV are based on a number of assumptions that merit our final checks.

The first assumption is that the linear regression given by (1) is empirically reasonable for quantifying wind generation's price-reduction effect in the Pacific Northwest. As noted by an insightful referee, fundamental drivers of whole market price can have nonlinear impacts. If not properly accounted for, these nonlinear impacts may bias our determination of wind generation's price effect. Hence, we explore the possibility of nonlinear impacts by first estimating a quadratic specification with 27 linear, squared and cross-product terms of the six continuous variables, $(x_H, x_C, x_G, x_N, x_F, x_W)$, on the right-hand-side of (1). For the peak price data, this regression only has eight statistically significant ($\alpha = 0.01$) coefficients for the 27 terms, thus suggesting over-specification.

To remedy the over-specification problem, we estimate another regression with linear and squared terms for the six continuous variables. The squared term for wind is highly insignificant ($p = 0.6828$) and only two of the four weather terms are significant ($\alpha = 0.01$). As a result, we proceed to estimate a regression that modifies (1) by only including squared terms for the Henry hub natural gas price, Dalles Dam discharge and BPA's nuclear generation. While these squared terms are statistically significant ($\alpha = 0.01$), their presence does not materially alter the coefficient estimate for wind generation. To specify, this regression's estimate for β_6 is -0.00088 ($p < .0001$), close to the estimate of -0.00096 reported in Table III.

We perform similar analysis for the off-peak price data and the resulting estimate for β_6 is -0.00070 ($p < .0001$), which is also close to the estimate of -0.00072 reported in Table III. Taken together, this finding and those for the peak price data suggest that allowing for nonlinear impacts does not alter our inference of wind generation's price effects in the Pacific Northwest.

The second assumption is that the wind-generation variable x_W is measured by the daily average of BPA's 5-minute wind generation in MW; that is, the wind-generation effect is assumed

[4]Since a 100-MW increase yields 25-MWH in a 15-min interval, its price-reduction effect in ERCOT is $\$0.0039/\mathrm{MWH} * 25\ \mathrm{MWH} = \$0.0975/\mathrm{MWH}$ for the Houston zone [30, Table 2].

[5]The marginal generation unit in the Pacific Northwest during the hydro run-off season of April to June is hydro, but the system-load conditions during these months are relatively low. For the rest of the year, however, the Pacific Northwest's day-time marginal generation is combined-cycle gas turbine or combustion turbine fueled by natural gas.

TABLE V
WIND GENERATION'S COEFFICIENT ESTIMATES OF THE AR(1) REGRESSIONS WITH PARTIAL ADJUSTMENT BY PRICE-EFFECT SPECIFICATION; p-VALUES IN ()

Alternative specification	Daily Mid-C daytime price ($/MWH): 06:00 – 22:00		Daily Mid-C nighttime price ($/MWH): other hours	
	α_6	γ_6	α_6	γ_6
1. $\alpha_6 x_{WD.} + \gamma_6 x_{WN}$ for both daytime and nighttime regression	-0.000663 (0.0705)	-0.000293 (0.4586)	-0.000576 (0.0016)	-0.000112 (0.5971)
2. $\alpha_6 x_{WD.}$ for the daytime regression	-0.000888 (<.0001)			
3. $\gamma_6 x_{WN}$ for the daytime regression				-0.000622 (<.0001)

TABLE VI
COMPARISON OF THE MAXIMUM LIKELIHOOD ESTIMATES FOR β_6, THE DAILY WIND GENERATION'S COEFFICIENT FOR THE MID-C PRICE REGRESSIONS IN TABLE III

Data type of wind generation	Daily Mid-C daytime price ($/MWH): 06:00 – 22:00			Daily Mid-C nighttime price ($/MWH): other hours		
	Estimate	Standard error	p-value	Estimate	Standard error	p-value
Actual daily average MW of BPA's wind generation	-0.00096	0.00022	<.0001	-0.00072	0.00013	<.0001
Forecast daily average MW based on the persistence model	0.00007	0.00022	0.7481	0.00021	0.00013	0.1030
Forecast daily average MW based on the Holt-Winters exponential smoothing method	-0.00029	0.00043	0.4886	0.00018	0.00027	0.5028

to be $\beta_6 x_W$. We compare the estimates for β_6 with those obtained under three alternative specifications: 1) the effect in each regression is $(\alpha_6 x_{WD} + \gamma_6 x_{\mathrm{WN}})$, where x_{WD} = average daytime MW and $x_{WN}\cdot$ = average nighttime MW; 2) the effect in the daytime regression is $\alpha_6 x_{WD}$; and (3) the effect in the nighttime regression is $\gamma_6 x_{WN}$. Table V shows that the coefficient estimates under these alternative specifications are smaller in size than those shown in Table III; or, the alternative specifications tend to reduce the price- reduction effect of wind generation.

The third assumption is that the actual wind generation is an adequate proxy for the unobservable consensus wind-generation forecast made by bilateral traders. An alternative is to directly use an MW forecast in the regressions. To do so, we make two forecasts, the first of which is based on the persistence model so that the day-ahead forecast is the most recent wind MW recorded, while the second is based on Holt-Winters exponential smoothing in PROC FORECAST in SAS.

We use these two forecasts as follows. First, we include the forecast variables in each price regression in Table III and perform a likelihood ratio test to determine if the actual wind variable should be used in the regressions.[6] While the test results reject $(\alpha = 0.01)$ the alternative hypothesis, they only do so marginally.[7] Second, after replacing the actual MW value with its forecast, we re-estimate the regressions. Table VI compares the estimates for β_6, the daily wind generation's coefficient, showing that when the forecasts are used, the coefficient tends to have a counter-intuitive and insignificant positive value. Hence, we do not use the forecast alternatives in our analysis.[8]

The last assumption is that the error term in the regressions reported in Tables III and IV follows an AR(1) process. It is based on our test result that the error term does not follow an AR(2) process. We also tried alternative error specifications that allow for time-dependent variances (i.e., ARCH and GARCH), as was done in [28]. We rejected these alternative specifications because 1) the estimates in Tables III and IV are insensitive to the choice of error specification, and 2) the estimated variance process is unstable and yields unreasonably large variances.

VI. CONCLUSION

As electricity markets around the world increase their dependence upon wind generation, it becomes increasingly important to understand how this intermittent renewable energy source with negligible operating costs will affect the prices paid by end-users and the economic incentive to construct additional generating capacity. There is now an extensive literature explaining how wind generation can have an impact on prices via "merit order effects" in capacity-constrained markets dominated by fossil-fueled generation. The exact magnitude of the impact in various markets will vary, depending upon market design, the presence of special incentives for wind generation (e.g., production tax credits), and a host of other factors.

There are, however, a number of regions of the world where hydro power dominates the generation mix, including areas of Canada, Brazil, China, Iceland, New Zealand, and the Pacific

[6]The null hypothesis is H_0: both the actual and forecast wind variables should be part of the regression's drivers; and the alternative hypothesis is H_1: only the actual wind variable should be included. The test statistic is $\chi^2 = -2$ (LL under $H_1 - LL$ under H_0) with two degrees of freedom, where LL = maximum value of the log-likelihood function at convergence.

[7]The χ^2 values are: 1) 11.2 for the daytime regression and 2) 10.5 for the nighttime regression. These values marginally exceed the critical value of 9.21 for $\alpha = 0.01$ at two degrees of freedom.

[8]These results may only reflect the poor quality of our wind-energy forecasts. We have tried to obtain wind-energy forecast data from BPA's website: http://www.bpa.gov/Projects/Initiatives/Wind/Pages/Wind-Power-Forecasting-Data.aspx, but the BPA data series only starts in June 2012, which is much shorter than our sample period, and thus is not useful for our estimation purpose.

Northwest region of the U.S. For those regions, the economics of wind-power integration may be quite different. Our findings suggest that in hydro-dominated regions where formal wholesale markets for power exist or may be established, additional wind generation may still impact prices, especially when the marginal generation fuel is natural gas. Specifically, wind generation's price-reduction effect with no transmission constraints is similar in the Pacific Northwest and ERCOT. This is a remarkable but understandable result because when two regions have similar marginal generation units fueled by natural gas, wind generation should have a similar price-reduction effect. When there are transmission constraints, however, the price-reduction effect of wind generation can be large, as in West Demark and ERCOT's West Zone. These findings lend support to our regression approach as a straightforward and transparent means to identify and quantify the price-reduction effect of wind generation across different systems and markets.

The relatively small price-reduction effect of wind generation reported herein should not be taken as a reason to discourage wind development in hydro-rich regions. Indeed, it may be easier to integrate wind power into a market that is dominated by hydroelectric generation than into a market dominated by fossil-fueled generating units. The generation output from typical hydro facilities may be adjusted in a fairly rapid manner to compensate for imbalances resulting from unexpected fluctuations in wind generation. This has led to proposals for the submission of combined wind generation and hydro offers into power markets [26]. Consequently, it is also eminently plausible that greater penetration of intermittent wind power into hydro-dominated markets will not greatly increase the volatility of wholesale electricity prices. There may be minimal need to increase operating reserves or construct new generation to accommodate a modest increase of up to five percent of total system capacity in wind power in hydro-rich markets, where hydro units can respond quickly to changes in wind generation. Thus, both the technical challenges and the economic impacts of wind integration in hydro-rich markets may be modest, compared to those faced in markets dominated by thermal generation.

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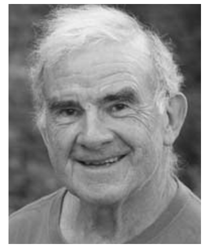

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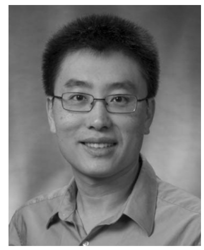

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