Gone with the Wind: Consumer Surplus from Renewable Generation

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Abstract

I use a simple equilibrium framework to analytically show how a short run increase in the quantity of renewable generation should impact the wholesale price of electricity. This is a function of the slope of demand and supply, as well as a parameter for the conduct of market participants. Conduct has the potential to be important in wholesale electricity markets, as they are typically structured as multi-unit uniform price auction where there is an incentive to withhold generation proportional to the quantity a market participant produces. Taking advantage of detailed data on the largest wholesale electricity market in the United States, I calculate the expected price reduction associated with increased renewable generation under different assumptions on firm conduct. Evidence and theory show it is the horizontally integrated firms, owning wind turbines and conventional electricity generators, that withhold their ex-ante generation offer in response to their own wind generation. As a result, over 30% of wind generation is replacing these withheld units suggesting a decrease in consumer surplus of 2 to 3 billion US Dollars from 2014 to 2016.

JEL classification codes: L13, Q42, D44
Keywords: Wholesale Electricity, Physical Withholding, Merit Order Effect, Renewable Generation, Supply Function Equilibrium, Consumer Surplus.

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1 Introduction

From 2008 to 2016 more than 50% of new electricity generation capacity within the U.S. has been from investments in wind and solar. At the same time, there has been a precipitous decline in the number of coal powered electricity generating units (EIA, 2017). While the environmental benefits of this market transition have been given significant attention, the private benefits associated with reduced operating costs can be just as large, if not larger (Callaway, Fowlie, and McCormick, 2018). This is because renewable generation does not require fuel to generate electricity, whereas steam and combustion generators do. The extent to which this reduced operating cost lowers the market price of electricity, or increases profit for the producers, has implications for investment incentives, incidence, public policy, and market design. To address this issue, I use detailed micro data on firm specific strategies to quantify the price reduction and consumer surplus associated with short run increases in renewable generation, taking into account the competitive behavior of market participants, for a large wholesale electricity market in the Midwest United States from 2014 to 2016.

In wholesale electricity markets where demand is highly inelastic in the short run, emission costs can be perfectly passed-through to the market price (Fabra and Reguant, 2014). In contrast, the cost savings associated with increased renewable generation might not pass-through to the wholesale price for a number of reasons. For one, the electricity market is comprised of horizontally integrated market participants owning multiple generating units, including wind turbines and conventional electricity generators.[1] In theory, this imperfection in competition has the potential to perfectly offset the price reduction from increased renewable generation under Cournot Competition (Acemoglu, Kakhbod, and Ozdaglar, 2017). In addition, not all market participants benefit from increased renewable generation, only those that own wind turbines. When there are firm specific cost shocks, the price reduction is expected to be less than the change in cost (Sweeny and Muehlegger, 2017). Finally, there is a known incentive to withhold generation in a wholesale electricity market structured as a multi-unit uniform price auction (Ausubel et al., 2014). This incentive is proportional to the total quantity produced by a market participant (Wolfram, 1998), and wind generation is an exogenous increase in the quantity produced by diverse firms. For these reasons it is important to empirically evaluate how the market price changes relative to what would be expected by economic theory.

Many papers have evaluated the integration of renewable generation in electricity markets, uncovering a "merit order effect" where low cost generation displaces high cost generation and lowers the market price, as shown in Figure 1. These papers either consider a simulation model (Sensfuß, Ragwitz, and Genoese 2008; McConnell et al. 2013), or empirically estimate the change in price due to renewable generation (Woo et al. 2011; Cludius et al. 2014; Clò, Cataldi, and Zoppoli 2015; Woo et al. 2015, 2016). The results are location specific, often determined by the fuel mix and fuel prices, and are not trivial in magnitude. For example, Woo et al. (2016) find that a one gigawatt hour (GWh) increase of wind generation in California lowers the wholesale market price by \$1.5 to \$11.4 per megawatt hour. This implies average hourly wind generation can lower total market revenue by millions of dollars per day.[2] While the estimates provided in these papers

[1] I define conventional electricity generators as steam, combustion, hydrological, or nuclear powered alternating current electricity generators.

[2] The average hourly wind generation is California is around 1 GWh and the total load is around 24 GWh. If 1 GWh of wind generation reduces the price by 6.5 \$/MWh, for 24,000 MWh in a hour, for twenty-four hours, revenue declines by 3.7 million USD that day.

are informative, they either assume a competitive economic dispatch or provide no context for how we would expect the price to change.

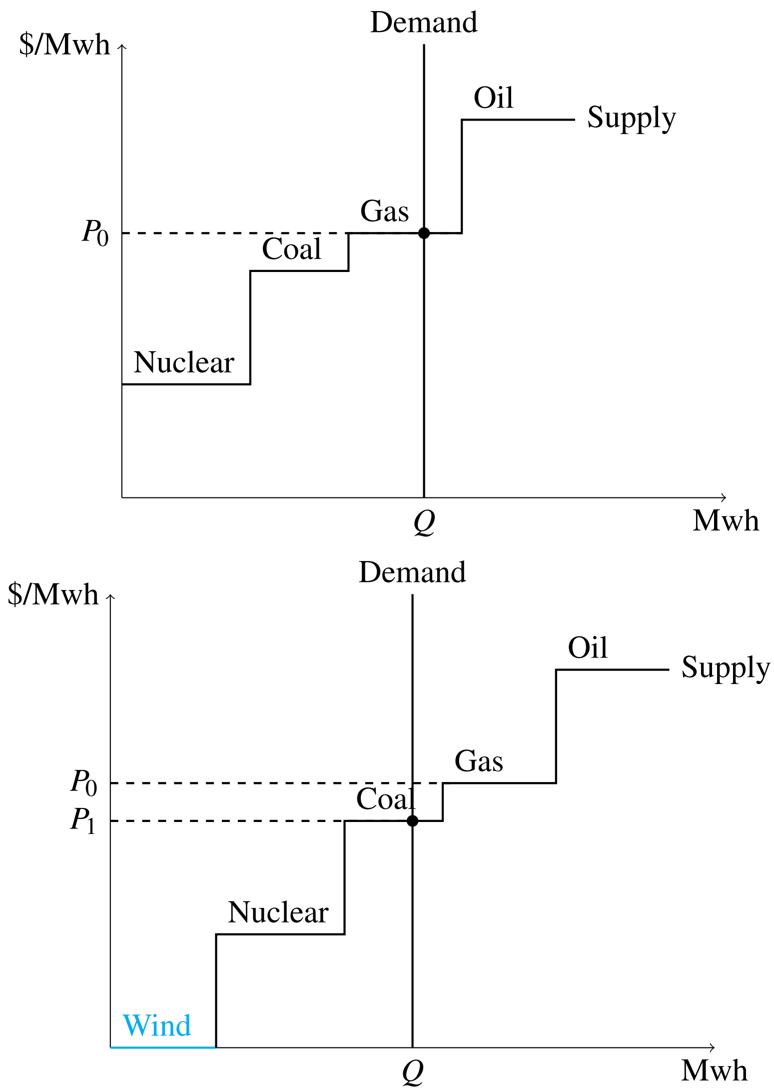

Figure 1: The Merit Order Effect of Increased Renewable Generation. Electricity markets are conceived as a Merit Order, where the lowest cost resources have merit and are dispatched first. When wind turbines generate electricity, it is believed they displace higher cost units as wind generation shift the supply curve to the right. As a result of the supply shift the equilibrium price of electricity decreases, from P_0 to P_1, displacing higher cost electricity generating units.

My contribution to the this literature is two-fold. First, I derived an analytical expression for the merit order effect as a function of fundamental market components: the slope of supply, the slope of demand, and a parameter for every market participant's conduct. This provides intuition for the conditions under which renewable generation is expected to have the largest impact on price. Second, I exemplify the importance of firm behavior by showing how this analytical merit order effect changes under two contrasting modeling assumptions. One model assumes market participants submit bids equal to their cost of production, the other is supply function equilibrium (SFE) framework of Klemperer and Meyer (1989), as applied to electricity markets by Hortacsu and Puller (2008). In this imperfectly competitive SFE model, there is an incentive for firm's to withhold their generation offer as in Acemoglu, Kakhbod, and Ozdaglar (2017); Ausubel et al. (2014).

In application I consider a third, less structural, alternative that estimates parameters of conduct for every firm in MISO. I do this by observing how the supply functions submitted by market participants change during windy hours.[3] These supply functions represent the quantity each market participant is willing to generate at a given price, ex-ante, therefore any inference is in regards to the market participant's strategy. While a large number of market participants do not change their supply function in response to increased wind generation, diverse market participants that own both wind turbines and conventional generation assets tend to offer less electricity from their conventional generators.[4] These market participants have an incentive to use their conventional assets to prevent price reductions, as the quantity produced from their wind turbine is not marginal.

This shuffling of electricity generation by resource type within a particular market participant's portfolio has important implications for our understanding of wholesale electricity markets. In an ideal competitive wholesale market, the lowest cost resource is given priority and replaces higher cost resources when available. As a result, wind generation should displace the highest cost generating unit. However, when market participants reduce the quantity they offer when their own wind turbines are generating electricity, their wind generation is replacing their own units regardless of the cost to run those units. This inefficiency reduces total economic surplus, and transfers the surplus from consumers to producers of electricity. The producers owning wind turbines have all of

[3]Fabra and Reguant (2014) use a similar method to see how a market participant's generation offer changes with emission credit prices in Spain.

[4]I use the adjective diverse to define market participants that own wind turbines and conventional electricity generators.

the benefit of lower fuel cost without the reduction in the market price. Conversely, the consumers of electricity in the wholesale market do not get the benefit of lower prices.[5]

Renewable generation has had a substantial impact on the price of electricity and has increased consumer surplus in the wholesale market overall. With the detailed data and analytical predictions on how the price should decline, I make credible claims regarding the change in consumer surplus due to increased renewable generation. I calculate this for both the perfect competition and the supply function equilibrium framework, showing over 70% of consumer surplus disappears if diverse market participants withhold perfectly in line with their incentives. Using empirical estimates of physical withholding due to renewable generation, I quantify the change in consumer surplus due actual physical withholding observed in MISO. While the reduction in consumer surplus is less than what would be expected in the supply function equilibrium framework, physical withholding by diverse generators has reduced consumer surplus by 2.2 to 3.2 billion USD from 2014 to 2016, equivalent to 15 to 22 USD per person per year.

The paper proceeds as follows, section 2 outlines a general framework for understanding how renewable generation, in particular wind, impacts the price of electricity in wholesale markets. Section 3 provides context by describing the wholesale electricity market I study, the data I use, and estimates of the change in price under the two assumptions on firm conduct. Section 4 turns to micro-data on firm strategies, showing evidence of physical withholding during windy hours. Section 5 summarizes the implications of withholding for consumer surplus, section 6 concludes.

2 Wind generation in wholesale electricity markets

The following is intended to model a wholesale electricity market operating as a multi-unit uniform price auction that allows for diverse market participants and a degree of low variable cost renewable generation. Demand for electricity is determined by Load Serving Entities, predominately utilities, that charge customers a rate for electricity in the retail market.[6] These Load Serving Entities submit demand bids for each hour that can be price sensitive. I model aggregate demand at time

[5] Consumers in wholesale electricity markets are typically utilities that serve residential, commercial and industrial customers. It is possible the producers and consumers are vertically integrated, which I do not observe.

[6] Load Serving Entities in wholesale markets can also be generators of electricity if they are vertically integrated.

t as $D_t(p) = d_t(p) + \varepsilon_t$ where $d_t(p)$ is the deterministic component of demand as a function of price that can be forecasted and ε_t is a random variable representing fluctuations in the quantity demanded. I model ε_t to be an *i.i.d.* random variable with expectation equal to zero.

Supply in the wholesale electricity market is provided by market participants, which I denote by the subscript o, who own multiple electricity generating assets including coal, gas, nuclear, wind, or hydrological based resources. Each conventional unit owned by market participant o, denoted by the subscripts $k \in K_o$, submits a unit-specific supply curve as a function of price, $s_{kt}(p)$. This offer curve represents the quantity the market participant o is willing to produce from unit k at time t for price p. I consider the market participant's aggregate supply sans wind generation as $S_{ot}(p) = \sum_{k \in K_o} s_{kt}(p)$. When the uniform market clearing price is $\hat{p}$, the market participant will produce $S_{ot}(\hat{p}) = \sum_{k \in K_o} s_{kt}(\hat{p})$ with costs $C_{ot}(S_{ot}(\hat{p}))$ and revenue $\hat{p} S_{ot}(\hat{p})$.

Wind at time t is modeled by an aggregate quantity, W_t that is decomposed in to a deterministic forecasteable quantity, w_t, and a random variable, ω_t, such that $W_t = w_t + \omega_t$ where w_t is common knowledge to all market participants. Similar to ε_t, ω_t is an *i.i.d.* random variable with expectation equal to zero.[7] The proportion of wind that is owned by market participant o is denoted by $\theta_o \in [0,1]$, with $\sum_o \theta_o = 1$. This implies the amount of wind generated by market participant o is $\theta_o W_t$. As a simplification, this modeling assumption states that the electricity generated by wind for any market participant is directly proportional to their wind generation capacity.[8] In this model I assume that wind generation always clears at the equilibrium because of its low variable cost.[9]

The price concept most common in U.S. wholesale electricity markets is a Locational Marginal Price (LMP). This price represents the marginal cost of increasing energy production at any given moment and at any given location within the market, and therefore varies by location (at different pricing nodes) and by time (typically at 5 minute intervals). The LMP can be decomposed

[7] It is possible that wind shocks are correlated over time, or with demand. It is not essential to the results presented.

[8] While this is restrictive, I relax the assumption in the empirical application.

[9] I assume the variable cost of production for wind turbines is zero as it does not require fuel. There are other variable operation and management cost associated with wind turbines, but the Federal Renewable Energy Production Tax Credit is larger than these costs. It is possible that wind generation can be curtailed manually, however the market I study, MISO, has incorporated wind generation as part of the economic dispatch since 2011, resulting in a curtailment rate of less that 1%.

into three exclusive components: the Marginal Energy Component (MEC) determined as the price where supply equals demand at a load-weighted reference node, marginal congestion cost associated with the shadow price of system transmission capacity constraints and out of merit dispatch, and marginal losses associated with transmitting the electricity over long distances. At any given moment, the MEC is the same at every location within the market while the losses and congestion components vary by node.[10] Analytically, I consider the price p to represent the MEC of the LMP. For most hours, the MEC is the largest component of the LMP.

2.1 Market Equilibrium and the Analytical Merit Order Effect

Moving forward, I will suppress the time subscript for notational ease. The market operator takes the supply offers as given, observes the realized demand and wind shocks, ε and ω, to solve for the dispatch quantity for each firm and the price received in accordance with a security constrained dispatch algorithm. Outside of security constraints and reliability concerns, we can think of the market clearing as follows:

$$\underbrace{d(p)+\varepsilon}_{\text{demand } D(p)} = \underbrace{\sum_o S_o(p)}_{\text{conventional supply}} + \underbrace{w+\omega}_{\text{wind } W} \tag{1}$$

Implicitly differentiating the market clearing condition with respect to total wind generation, W, gives the equilibrium effect of increased renewable generation on wholesale market price.[11]

$$\frac{dp}{dW} = -\frac{1+\sum_o \frac{\partial S_o(p)}{\partial W}}{\sum S_o'(p) - d'(p)} \tag{2}$$

Where $'$ denotes the partial derivative with respect to the function's main argument. Equation 2 is the rate at which an increase in renewable generation impacts the equilibrium price, what I am calling the analytical merit order effect. This value depends on the supply function slope, demand slope, and the strategic response by market participants. The intuition of Equation 2, when demand is inelastic and $\frac{\partial S_o(p)}{\partial W}$ is equal to zero, is shown in Figure 1 where the change in the price of electricity is determined by the difference in price submitted for the marginal unit, $-\frac{1}{\sum_o S'(p)}$. This

[10]Some markets are known for very high and sometimes negative prices at times, this is typically because of the congestion and loss components.

[11]I assume that the quantity demanded does not depend on the quantity of wind generated, that is $\frac{\partial D(p)}{\partial W} = 0$.

can be thought of as the pass-through of increased renewable generation. This is related to, but different from, the conventional pass-through rate of a cost shock or tax. [12]

Electricity markets are often considered to be imperfectly competitive because of capacity and transmission constraints, a degree of market power, as well as vertical and horizontal relations. I incorporate competitive conduct into Equation 2 with the inclusion of $\frac{\partial S_o(p)}{\partial W}$ in the numerator. Without placing structure on the market or market participants' incentives it is impossible to sign this value. The sign of this term suggests the extent to which increased renewable generation has a pro- or anti- competitive effect on firm's behavior. If the term is positive the market participant offers more generation quantity to the market at any given price in response to increased renewable generation. This pro-competitive outcome arises if the firm is trying to ensure their generation clears in the market, and is not displaced by the increased renewable generation.[13] The implications is that renewable generation would decrease the price by more than the change in cost. Conversely, when the term is negative, the supplier is offering less quantity to the market at any given price. This anti-competitive outcome would be an attempt by the firm to keep the price high, and offset the lower price associated with increased renewable generation.

2.2 Market Participants' Strategy

To understand how a firm might change their strategy in response to increased renewable generation, I consider two models of the market participants' behavior. One model assumes market participants have strategies as if they are in a perfectly competitive wholesale electricity market, the other uses a supply function equilibrium framework. These will provide two different predictions for $\frac{\partial S_o(p)}{\partial W}$, implying different values for the analytical merit order effect, $\frac{dp}{dW}$. For each prediction, I use the detailed data I have on market hourly supply and demand to explicitly calculate the analytical merit order effect.

In a perfectly competitive market, firms are price takers and submit a supply function that

[12] To show this, consider the market equilibrium with a unit tax, $d(p) = \sum S_o(p-t)$, under perfect competition. Implicitly differentiating the market equilibrium with respect to t uncovers the well-known pass-through formula $\frac{dp}{dt} = \frac{\sum S_o'}{\sum S_o' - d'} = \frac{1}{1+\frac{\varepsilon_D}{\varepsilon_S}}$ where ε_D and ε_S denote the own-price and market supply elasticities respectively.

[13] Ciarreta, Espinosa, and Pizarro-Irizar (2017) finds evidence of this in the Spanish electricity market by looking at the difference in the offer curves over long periods of time.

outlines the inverse of their marginal cost of production. This would be independent of W implying that $\frac{\partial S_o(p)}{\partial W} = 0$. Substituting this into Equation 2 we have that

$$\frac{dp_{comp}}{dW} = -\frac{1}{\sum S_o'(p) - d'(p)} \tag{3}$$

and for an observed quantity of wind based generation in an hour, the total price effect would be

$$dp_{comp} = -\frac{1}{\sum S_o'(p) - d'(p)} dW \tag{4}$$

From an incidence perspective, this represents the upper bound of the price reduction associated with increased renewable generation and can be used to calculate to the potential consumer surplus available.

Conversely a firm with market power might internalize the benefits associated with increased renewable generation. Figure 2 provides the intuition. When a market participant with market power is considering the incentives to withhold, they are comparing a higher price and smaller quantity to a lower price and larger quantity. When this market participant owns a wind turbine that is also generating electricity, they receive additional benefit of increasing the price directly proportional to the quantity of electricity generated by their wind turbine. This is because they receive additional revenue from the wind turbine, as they are infra-marginal, but do not incur any cost.

I use the supply function equilibrium framework (SFE) outlined by Hortacsu and Puller (2008) to derive the market participant's best response function.[14] Market participants choose the $S_o(p)$ that maximizes their expected profit, with the expectation taken over the uncertainty in price due to wind and demand shocks. Appendix A proves the optimal strategy of market participant o with conventional assets and wind turbines can be characterized by

$$\left[p - C_o'(S_o(p))\right] = \left[S_o(p) + \theta_o W\right] \frac{-1}{RD_o'(p)} \tag{5}$$

where $RD_o'(p) = d'(p) - \sum_{j \neq o} S_j'(p)$ is the slope of the residual demand curve for owner o. It is clear that an increase in the amount of electricity produced by wind, W, will be associated with a

[14] A major component in this model is forward contracts. These are used to identify firm behavior or cost of production. I ignore this component of the model as it is not directly tied to wind production. This is in contrast to Ito and Reguant (2016) who focus exclusively on wind generation and forward contracts in the Iberian Peninsula.

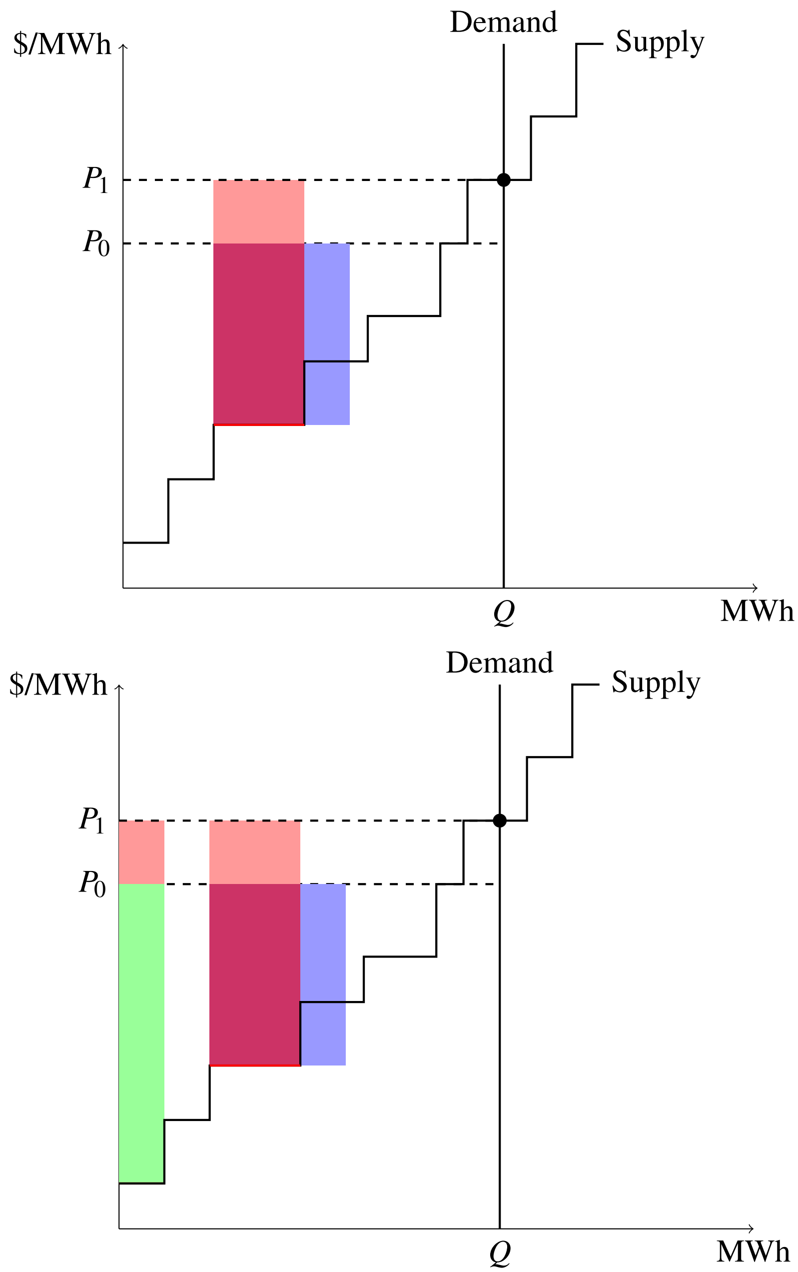

Figure 2: Incentive for Diverse Market Participants to Curtail. When a firm with market power considers the incentives to curtail they trade off a lower price with a larger quantity with a higher price and a smaller quantity. This trade off is represented in the top figure by the blue and light salmon rectangles. When the market participant is diverse, owning wind turbines and conventional generators, they receive additional revenue from a high price on their wind based assets. In the bottom panel, the green rectangle represents the revenue from the wind turbine if the firm does not curtail and the light salmon square shows the additional revenue received from the wind based asset if they curtail.

reduction in the supply curve offered to the market. For simplicity I assume that the marginal cost is constant near the equilibrium price, $C_o''(S(p)) = 0$, and that market participants do not change the slope of their offer curve in response to increased renewable generation, $\partial S_i'(p)/\partial W = 0, \forall i$, near the equilibrium price.[15] This provides $\frac{\partial S_o(p)}{\partial W} = -\theta_o$, a market participant will reduce their generation offer in response to a unit increase in renewable generation by the proportion of total wind generation they own.[16]

All market participants that do not own wind turbines have $\theta_o = 0$ implying $\frac{\partial S_o(p)}{\partial W} = 0$. Substituting the values of $\frac{\partial S_o(p)}{\partial W}$ into Equation 2, we have that the analytical merit order effect is

$$\frac{dp_{SFE}}{dW} = -\left(1 - \sum_{o \in V} \theta_o\right) \frac{1}{\sum S_o'(p) - d'(p)} \tag{6}$$

where V is the set of market participants that own both wind turbines and conventional assets. In aggregate this strategic withholding implies increased renewable generation will have the following impact on the market price

$$dp_{SFE} = -\left(1 - \sum_{o \in V} \theta_o\right) \frac{1}{\sum S_o'(p) - d'(p)} dW \tag{7}$$

This shows the impact on price paid by consumers in wholesale electricity markets depends on the ownership of the wind turbines. If all wind turbines are owned by market participants that also own conventional assets, then $\sum_{o \in V} \theta_o = 1$ and there would be no effect on price. Conversely, if wind turbines were owned exclusively by independent producers, then $\sum_{o \in V} \theta_o = 0$ and the expected price change would be identical to Equation 4.

3 The Midcontinent Independent System Operator and Data

The Midcontinent Independent System Operator (MISO) was formed in 1998 and approved as the first Regional Transmission Organization in the US by the Federal Energy Regulatory Commission in 2001.[17] The operator serves as a non-profit organization managing transmission and dispatch of electricity generating units within its foot print through a variety of market operations, focusing on

[15] Empirical evidence validates the assumptions regarding the change in the slope of supply at equilibrium prices.

[16] More broadly, this comparative static suggests that a market participant will withhold their conventional generation by the quantity of wind generated, one for one. Overall they are generating the same quantity of electricity, however they are replacing their conventional generation with wind generation.

[17] MISO was formerly known as the Midwest Independent System Operator up until 2013

reliability, efficiency, and the development of electricity resources. Since the incorporation of the Southern Region in 2013, MISO has become the the largest wholesale electricity market within the United States with a total of 180 gigawatts of generation capacity, and conducts market operations from North Dakota to Michigan to Louisiana. This includes part of The Great Plans, where there is the largest concentration of wind turbines within the United States. MISO operates a number of markets to achieve its goals in distribution and reliability including a day ahead and real time wholesale electricity similar to the model described in section 2. These markets capture almost all electricity generation and transmission activities within MISO's footprint that are not part of bilateral contracts.[18]

MISO publishes data regarding their market operations on their website as Market Reports. The primary data I use are the daily real time generation offers by generation units from January of 2014 to December of 2016.[19] I focus on the real time market because I am looking at actual wind generation, not forecasts. These data provide, for every hour, a time consistent unit and owner identification code, the generating unit type (steam, combustion, wind turbine, hydro), the ex-post quantity generated and LMP received at five minute intervals, as well as details on the generating unit's supply bid. Unit-level data on the hourly LMP received and the quantity generated for all units are summarized in Table 1. The sample average unit LMP is \$27.37/MWh with wind turbines receiving a lower than average LMP and combustion turbines receiving the highest LMP on average. This is because the LMP is lower when wind turbines generate electricity, while the combustion turbines only generate electricity when the LMP is high. In terms of unit level generation, steam turbines and combined cycle units produce the most electricity per hour. Overall I observe a total of 1,327 units during the sample, of which 213 are wind turbines.

As show by Equation 7, the impact of renewable generation on the price of electricity can depend on who owns the wind turbines so it is important to know the portfolio of unit types owned by every market participant. I take advantage of the time-invariant owner code associated with

[18] A market report from 2011-2012 suggests 20 to 30% of electricity generated in a year is through bilateral contracts. These bilateral contracts include agreements with groups outside of MISO and grandfathered contracts within MISO.

[19] The start date is a few months after when the Southern Region was integrated into MISO. The end date is when MISO stopped reporting unit specific identification numbers to preserve the privacy of the asset owners.

Table 1: Unit Level Summary Statistics

	Unit LMP USD/MWh		Unit-Hour MWh			
	Mean	Std. Dev.	Mean	Std. Dev.	Num. Units	Unit-Hour Obs.
Steam-Turbine	28.54	28.99	220.28	235.80	411	6,177,105
Combustion-Turbine	30.13	33.70	55.49	120.50	441	2,602,751
Hydro-Powered	29.66	32.56	14.35	63.13	83	1,405,800
Combined-Cycle	29.59	28.91	276.78	161.64	76	726,195
Wind-Turbine	23.11	27.12	27.61	39.06	213	4,689,910
Other	28.39	30.97	12.04	45.03	103	754,317
Total	27.37	29.82	114.02	186.56	1,327	16,356,078

Notes: Unit-Hour observations come from MISO Real Time Cleared Offers Market Report From January 1, 2014 to December, 24, 2016. The MWh produced and price received are reported at 5 minute intervals within a single hour. This is aggregated by hour using a sum and mean respectively.

the generating units in the supply offer data to measure market participants portfolios, as all units with the same owner code are owned by the same market participant. I consider the maximum quantity generated by a unit during the sample period as a measure of its capacity to calculate the portfolio of assets for every owner code. Figure 3 shows the portfolio for the thirty largest market participants and their corresponding owner code. It is evident that almost all of these market participants have diverse assets, and that some of the largest market participants own a sizable amount of wind generation capacity.

In addition to the micro-data on unit level offers, MISO's market reports include hourly market level information on average LMP, the marginal energy component (MEC) of the LMP, the hourly fuel mix, the number of binding transmission constraints, the shadow price of relieving the binding constraints, wind forecasts, and net exports. I supplement these data with daily weather measures from the National Oceanic and Atmospheric Administration averaged across all states in MISO, as well as daily day-ahead natural gas prices at Henry Hub from the Intercontinental Exchange. The first panel in Table 2 summarizes these data. This market is large, clearing 71 GWh in a hour on average. A little more than half this is provided by coal based generators, and a fourth by natural gas. Wind generation provides almost 5 GWh on average, with a maximum of 13.7 GWh. While wind generation is a small portion of the market overall, there are moments when wind turbines produce more electricity than all the nuclear plants with MISO, and wind can meet up to 20% of

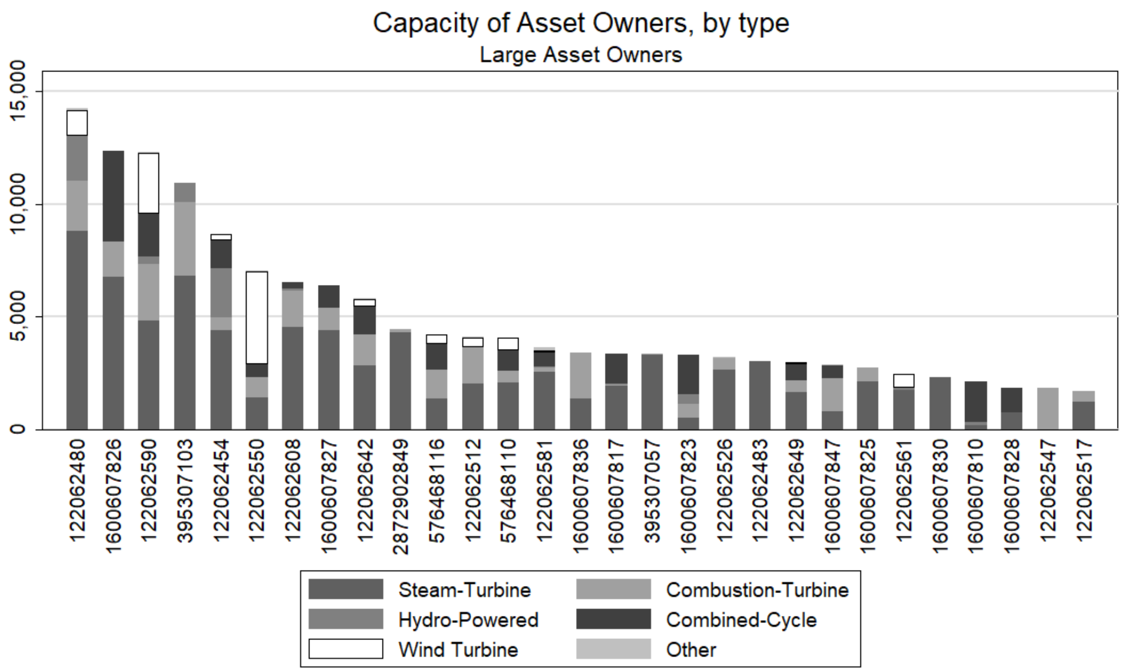

Figure 3: The capacity and portfolio of the thirty largest market participants in MISO. Capacity is measured as the maximum MWh produced by a unit during the entire sample period. The bar labels is the Market Participant's coded identification number. This shows the large and diverse market participants that own wind and conventional assets.

load during periods of low demand.

Hourly unit level supply offer data include up to ten price-quantity pairs that outline the quantity each unit is willing to produce at a given market price. I reconstruct unit specific supply curves for the hour by interpolating the price-quantity pairs on a common support (e.g. from -10 dollars to 100 dollars at an interval of 1 dollar). When appropriate, I extrapolate the quantity offered using the maximum and minimum quantity offered. To ensure the function is everywhere differentiable and monotonic I smooth the offer curve using a normal kernel following Wolak (2007). For a set of price and quantity pairs p_{ikt} q_{ikt}, $i = 1 \ldots N$ for unit k at time t, the smoothed supply function is

$$\hat{s}_{kt}(p) = \sum_i q_{ikt} \Phi\left(\frac{p - p_{ikt}}{h}\right)$$

where Φ is the standard normal cumulative distribution function and h is the bandwidth.[20] Figure 4 shows all offer curves of a sample unit and sample hour for one hour of day in a month.

To find the slopes at equilibrium, I aggregate all of the generation unit supply curves within

[20]I use a bandwidth of three dollars, as does Kim (2017). Changing the bandwidth does not alter the results.

Table 2: Market Level Summary Statistics

	Mean	Std. Dev.	Min.	Median	Max.	Observations
Panel A						
Market LMP, USD/MWh	27	20.8	-26.8	23.7	1,571	26,117
Market MEC, USD/MWh	29.9	22.7	-28.7	25.8	1,806	26,117
Market GWh Generated	71.4	12.6	42.1	70.4	116	26,117
Coal GWh	36.8	8.46	16.5	36.6	56.8	26,117
Gas GWh	15.9	6.21	4.57	15.3	43.4	26,117
Hydo GWh	.988	.5	.305	.843	3.29	26,117
Nuclear GWh	11.4	1.23	6.1	11.7	13.3	26,117
Other GWh	1.35	.852	.295	1.07	7.74	26,117
Wind GWh	4.96	2.79	.132	4.61	13.7	26,117
Wind GWh, Diverse	3.58	2.1	.0551	3.29	10.2	26,117
Wind GWh, Indpendent	1.37	.722	.0693	1.3	3.61	26,117
Shadow Price of Constraints	-.947	1.28	-17.3	-.506	0	26,117
Number of Binding Constraints	3.79	2.65	0	3.17	19.2	26,117
Max Daily Temperature, C	17.6	10.4	-11.7	19.5	33.4	26,117
Natural Gas Price, USD/MMBtu	3.13	1.01	1.49	2.84	7.88	26,117
Net Exports GWh	4.41	1.99	-1.77	4.27	11.6	26,117
Wind Forecast Error, GWh	-.00594	.965	-4.13	.00101	4.32	26,093
Panel B						
Equilbrium Price, USD/MWh	26.6	7.13	15	25	101	26,117
Supply Slope, $\Delta MWh/\Delta \frac{USD}{MWh}$	2,482	1,202	32.5	2,524	6,217	26,117
Demand Slope, $\Delta MWh/\Delta \frac{USD}{MWh}$	-5.12	6.91	-56.5	-1.99	0	26,117

Notes: Market-Hour observations from January 1, 2014 to December, 24, 2016. Market LMP, from the Nodal LMP Market Report, is taken as the average of all LMPs with an hour. The MEC is found by subtracting the Loss and Congestion Component from the LMP for each hour. Generation quantity in GWh comes from the Fuel Mix Market Report. The decomposition of Wind into Diverse and Independent Owners comes from the Cleared Offers Market Report. Diverse is defined as wind generation that is owned by a market participant that owns assets other than wind turbines. Independent wind comes from market participants that own only wind based resources. Shadow Price, in thousand USD, and Number of Binding Constraints comes from MISO's Real Time Binding Constraint Market Report. Temperature data is an average of all temperature readings within MISO's footprint from the Global Historical Climatology Network operated by NOAA. Wind Forecast Error and day ahead Henry Hub natural gas price and comes from Yes Energy. The wind data is missing one day of data from June of 2015. Equilibrium Price, Supply Slope, and Demand Slope are recovered from the offer supply and demand curves. The equilibrium is where the offered supply net of wind equals the demand less of net exports.

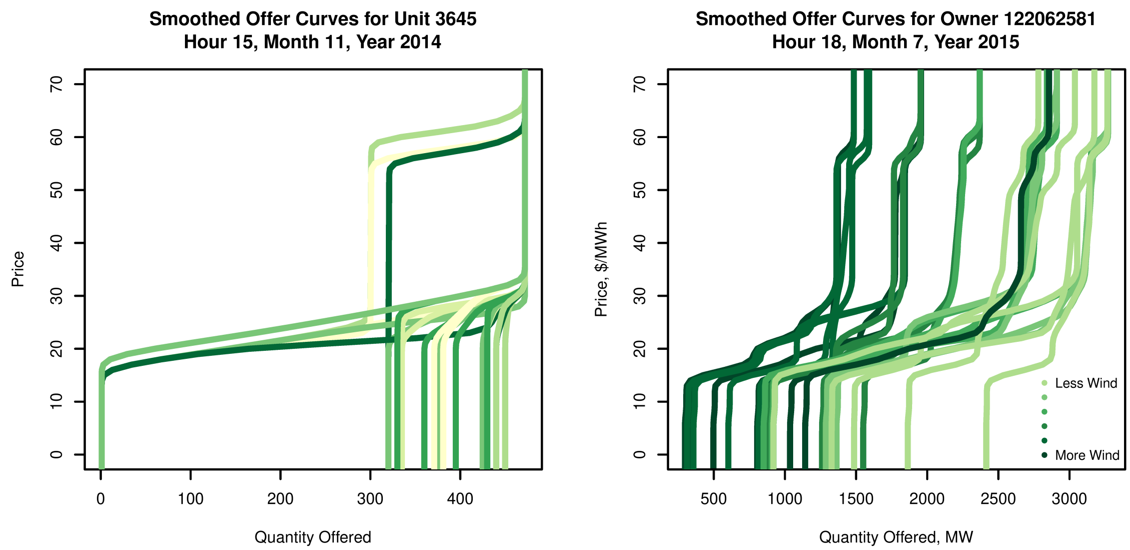

Figure 4: Two sets of sample offer curves. Each plot shows all offers for a particular unit during one Month Hour. This showcases the type of variation used in the bid level regression that include month-hour fixed effects. Darker lines are associated with windier hours. The left plot shows the offer curves for a single unit. The right plot shows the offer curve aggregated to the owner level.

MISO to obtain a market supply curve.[21] Because I am interested in the impact of wind on the price of electricity, I define the equilibrium as the aggregate supply without using the supply bids by the wind generating units. At this equilibrium I calculate the local slope of supply and demand as the difference in the quantity, along the curve, for a one step increase in price. The equilibrium prices and slopes are summarized in Panel B of Table 2. This price should correspond to the Marginal Energy Component of the LMP, however are not identical due to out of merit dispatch.

I use the slope of supply and demand, summarized in Panel B of Table 2 to calculate an exact expression of Equation 3 for every hour in my sample. I do the same for Equation 6 where I use the fraction of wind owned by diverse market participants in that hour for the value of $\sum_{o \in V} \theta_0$. Table 2 shows that on average the proportion of wind owned by diverse market participants is 72%. The resulting values are summarized as "Analytical Merit Order Effect, Competitive" and "Analytical Merit Order Effect, SFE" respectively in Table 3. For a one GWh increase in wind

[21] Here I define the entire MISO region as a single market. I've considered other market definitions including subregions within MISO and price clusters similar to Mercadal (2015). Because the Marginal Energy Component is the same for all units in MISO, and I am interested in how wind impacts the Marginal Energy Component, any other market definition is inappropriate.

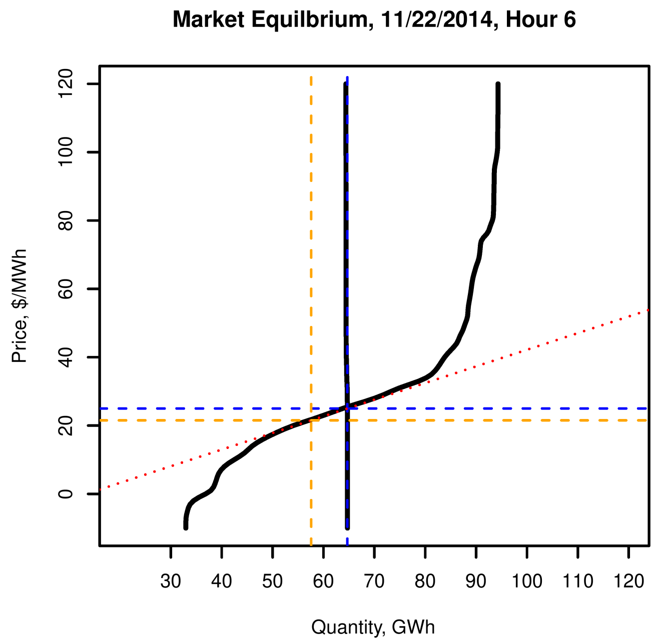

Figure 5: The reconstructed market supply and demand curves, in black, for a sample hour form the equilibrium price. The equilibrium is denoted by the dashed blue lines. The calculated merit order effect for a one unit increase is shown by the dashed red line. Walking down the merit order effect from the equilibrium shows the expected price reduction at with the yellow dashed lines.

generating for a given hour, we'd expect the price to decrease by \$0.63/MWh if market participants were acting competitively, and \$0.18/MWh if market participants were withholding according to their incentives. For context, the same increase in wind has been associated with a 3.18% price decline in Spain (Böckers, Giessing, and Rösch, 2013), 0.8 to 2.3 €/Mwh price decline in Germany (Cludius et al., 2014), 1.5 to 11.4 \$/Mwh price decline in California (Woo et al., 2016), and 3.9 to 15.2\$/Mwh price decline in Texas (Woo et al., 2011).[22]

To find the total price effect, I take the analytical merit order effect for an hour and multiply this by the quantity of electricity generated by wind for that hour. This provides values of dp_{comp} and dp_{SFE} from Equation 4 and Equation 7. The total price effect is \$3.5/MWh in a perfectly competitive market and around \$1/MWh according to the supply function equilibrium framework. These values vary tremendously, ranging from near zero to over \$100/MWh. This is consistent with the wholesale market where prices fluctuate greatly and can reach over \$1,000/MWh.

[22] It is important to note these numbers include the impact on wind generation on congestion and transmission.

Table 3: Analytical Merit Order Effect

	Mean	Std. Dev.	Minimum	Maximum	Observations
Analytical Merit Order Effect, comp.	-0.63	0.86	-30.73	-0.16	26,117
Analytical Merit Order Effect, sfe	-0.18	0.24	-8.97	-0.03	26,117
dp_{comp}, USD	-3.54	7.84	-360.81	-0.04	26,117
dp_{sfe}, USD	-0.97	2.10	-92.99	-0.02	26,117

Notes: Analytical Merit Order Effect comes from the theoretical prediction of the impact of 1 GWh of wind on the price of electricity with the corresponding assumptions on the price of electricity. Competition corresponds to Equation 3, the supply function equilibrium (sfe) corresponds to Equation 6. The values of $dp_{comp,sfe}$ come from Equation 4 and Equation 7 respectively, where the analytical merit order effect is multiplied by the GWh of wind based electricity. The slopes of supply and demand come from the equilibrium without wind bids and demand less of net exports. The value of $\sum_{o\in V}\theta_o$ is set equal to the proportion of wind that is generated by diverse market participants in a hour.

4 Evidence of Strategic Curtailment

While the merit order effects presented in Table 3 are informative, they rely on modeling assumptions. Here, I instead use detailed data on the strategies of all market participants for all hours to directly test for physical withholding. I begin by aggregating the conventional unit supply curves, described in section 3, by owner codes for every hour. This gives me a hourly supply curve of the conventional assets for every market participant on a common support, every \$3 interval between 0 and 60 dollars. These curves are defined by a set of $b = 1\ldots21$ price quantity pairs, (p_b, q_{otb}), for owner o at time t. The set of p_b are the same for all market participants, for all hours, only the quantities offered at these prices change.

To directly test for strategic physical withholding, I see how the quantity offered at a given price changes in response to increased renewable generation. The general estimating equation of interest is

$$q_{otb} = \gamma_0 ClearedGWh_t + \gamma_1 NetExports_t + \delta WindGWh_t + X\beta + \eta_{op_bymh} + \varepsilon_{otb} \tag{8}$$

where q_{otb} is the quantity offered, in MWh, by market participant o at time t and price bin p_b. X represents other determinants of a market participant's strategy including daily temperature measures, daily natural gas prices, the hourly number of binding constraints in MISO, and the hourly shadow price of all constraints. Identification comes from owner specific, month-of-sample by hour, fixed effects for every price bin, η_{op_bymh}. This captures the average quantity offered by market participant o at price p_b within a month-of-sample hour (e.g. September 2014, 4pm). Therefore the coefficient δ is identified off the deviation from the market participants month-of-sample hour average supply curve. Because these data represent the ex-ante strategy of a firm, withholding the quantity offered at a given price would imply that $\delta < 0$. The supply function equilibrium theory presented in section 2 suggest the coefficient of δ should be (1) negative for diverse market participants that own both wind turbines and conventional assets and (2) larger in response to a market participants own wind generation.

Table 4 shows the estimate of the δ in Equation 8 is negative. Overall, a 1 GWh increase in wind generation in an hour is associated with a 2 MWh reduction it the quantity offered at a given price on average across all market participants. In column (2), I interact $WindGWh_t$ with a indicator variable for if a market participant owns wind turbines and conventional assets. This shows that diverse market participants reduce the quantity offered by 10 MWh on average, while the independent market participants only reduce the quantity offered by 0.8 MWh. Finally, in column (3) I decompose $WindGWh_t$ into the quantity of electricity generated by independent wind turbines and the quantity of electricity generated by wind turbines owned by diverse market participants. This shows that the quantity offered by diverse market participants is reduced the most in response to diverse wind generation.

The estimates presented in Table 4 are the average effects for all market participants, or at best separated by if a market participant owns wind turbines. I expect there to be substantial heterogeneity in how market participants respond to increased renewable generations because they vary in the portfolio of wind based generation and their bidding sophistication.[23] I interact $WindGWh_t$ in Equation 8 with the owner code of every market participant to get a unit specific estimate of δ. In particular, I estimate the parameters in the following equation

$$q_{otb} = \gamma_0 ClearedGWh_t + \gamma_1 NetExports_t + \delta_o WindGWh_t \cdot OwnerCode_o + X\beta + \eta_{op_bymh}\varepsilon_{otb} \quad (9)$$

and plot the density of the coefficients in Figure 6 by if the market participant is diverse.[24] This shows the coefficients for the market participants that do not own wind generation are near zero,

[23] Hortacsu and Puller (2008) show evidence of imperfect bidding behavior by market participants in Texas's ERCOT market.

[24] Both densities use a Epanechnikov kernel with a bandwidth of 2 MWh.

Table 4: Curtailment of Offer Curve in Response to Wind Generation

	(1)	(2)	(3)
Market GWh Generated	2.830***	2.830***	2.831***
	(0.443)	(0.443)	(0.442)
Wind GWh	-2.338***		
	(0.598)		
Not Diverse Owner × Wind GWh		-1.101***	
		(0.223)	
Diverse Owner × Wind GWh		-10.78**	
		(3.752)	
Not Diverse Owner × Wind GWh, Indpendent			-2.269
			(1.387)
Diverse Owner × Wind GWh, Indpendent			-6.578
			(9.648)
Not Diverse Owner × Wind GWh, Diverse			-0.702
			(0.552)
Diverse Owner × Wind GWh, Diverse			-12.20*
			(5.085)
Owner-Price-Year-Month-Hour Fixed Effects	Yes	Yes	Yes
Other Controls	Yes	Yes	Yes
Observations	28,777,140	28,777,140	28,777,140
R-squared	0.97	0.97	0.97

Notes: Data comes from MISO Real Time Offer Market Reports January 1, 2014 to December 24, 2016. This sample is all offers by market participants during peak hours, defined as 3pm to 8pm inclusive. Offer curves are are interpolated and defined at 3$ intervals between 0 and 60 USD. All unit level offers are aggregated to the market participant. One observation is the quantity offered by all units owned by the same market participant at a given price for that hour. Diverse market participants own wind turbines and conventional electricity generating assets. Wind Based GWh, Independent, is wind based electricity generated by market participants that own only wind turbines. Likewise, Wind Based GWh, Diverse is wind based electricity generated by diverse market participants. All specifications include fixed effects for the average quantity offered by the market participant at the price for a given month-hour. Other controls include daily temperature, daily natural gas price, hourly number of binding constraints, hourly shadow price of all constraints. Standard errors, in parenthesis, are clustered by month of sample and owner. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively for each hypothesis test. The hypothesis test for all coefficients is $H_0 : \beta = 0$ vs. $H_1 : \beta \neq 0$.

where as the density for diverse market participants has an obvious left skew and is centered below zero.

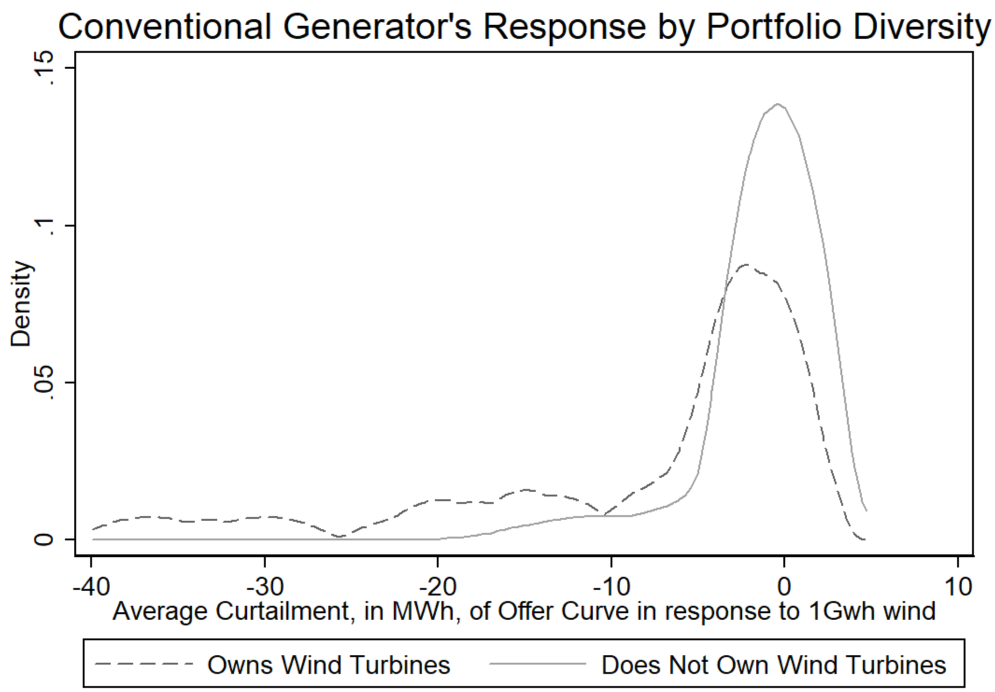

Figure 6: Kernel density of curtailment coefficients for ever market participant separated by the market participant's portfolio diversity. Curtailment coefficients are how the market participants offer curve changes in response to increased wind generation controlling for the month/year/hour/price/owner average quantity. Both densities use a Epanechnikov Kernal with a bandwidth of two dollars.

Finally, we are only interested in withholding of the quantity offered if it happens at or below the equilibrium price. To see how exactly a market participant is withholding their generation offer I estimate a separate withholding coefficient for all market participants at every price bin. Figure 7 shows the point estimates and confidence intervals of four large and diverse market participants. This shows the market participants respond more to their own wind than to the wind generated by others. This is consistent with the theory presented in section 2. These diverse market participants are withholding to increase the price received by their own wind turbines, not just to offset the price decline on their conventional assets.

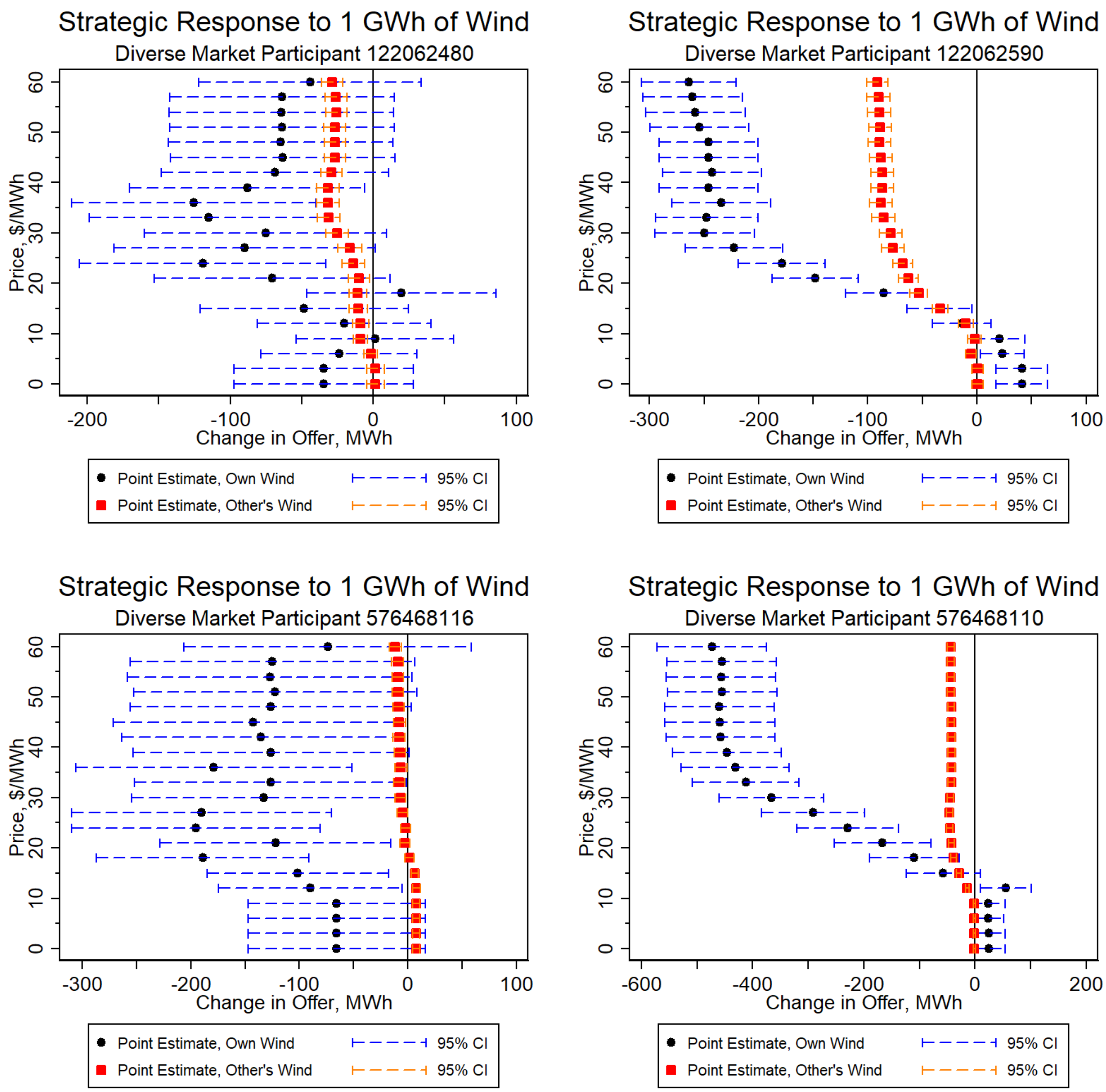

Figure 7: Curtailment coefficients at every price bin for a select number of large and diverse market participants. Estimates come from estimating Equation 8 with flexible price bins interacted with WindGWh, separately for each market participant. Confidence interval uses robust standard errors.

5 Implications for Consumer Surplus

Using the analytical merit order effect for the expected price change due to increased renewable generation it is possible to make claims regarding consumer surplus in the wholesale electricity market. I model consumer surplus from electricity during hour t at market price p as

$$CS_t(p) = \int_p^\infty D_t(x)dx$$

where $D_t(x)$ is the demand for electricity at time t and price x. To see how consumer surplus changes due to an increase in the quantity of wind, W_t, I take the total derivative to get

$$\frac{dCS_t}{dW_t} = -D_t(p)\frac{dp}{dW}_t$$

with the change in consumer surplus during the entire sample period would be

$$\Delta CS = -\sum_t D_t(p)\frac{dp}{dW}_t dW_t. \tag{10}$$

When calculating consumer surplus, I consider three alternative values for $\frac{dp}{dW}$. One is the prediction under the assumption of price taking behavior, where $\frac{dp_{comp}}{dW}_t = -\frac{1}{\sum_o S_o'(p) - d'(p)}$. For the second, I considered a supply function equilibrium framework with $\frac{dp_{sfe}}{dW}_t = -\left[1 - \sum_{o \in V} \theta_o\right] \frac{1}{\sum_o S_o'(p) - d'(p)}$ where $\sum_{o \in V} \theta_o$ is the proportion of wind owned by diverse market participants. Third, I use the estimates of physical withholding for diverse market participants from Equation 9 as an estimate of $\frac{\partial S_o}{\partial W}$.[25] Table 5 shows the estimates of δ_o for all diverse market participants. To calculate consumer surplus using the estimated withholding coefficients, I substitute the value of $\hat{\delta}_o$ in for $\frac{\partial S_o(p)}{\partial W}$ in Equation 2. The sum of these estimates, presented in the bottom of Table 5, suggests that over 30% of wind generation is replacing withheld offers by diverse market participants.

All together this provides me with three separate estimates of consumer surplus, all varying in

[25] To ensure I am looking only at relevant bid prices, I discard any observations where the market price is more than the price bin plus three, $p_b + 3$.I add three to the price bin because the price bins are at three dollar intervals.

Table 5: Owner Specific Curtailment of Diverse Market Participants

	(1)		(2)	
Owner.Code=122062454 × Wind GWh	-16.95***	(0.206)	-22.61***	(0.390)
Owner.Code=122062463 × Wind GWh	0.108	(0.222)	-1.345**	(0.428)
Owner.Code=122062474 × Wind GWh	-1.890***	(0.198)	-3.185***	(0.376)
Owner.Code=122062480 × Wind GWh	-22.57***	(0.205)	-31.25***	(0.390)
Owner.Code=122062486 × Wind GWh	-2.579***	(0.202)	-3.465***	(0.386)
Owner.Code=122062512 × Wind GWh	-13.25***	(0.192)	-19.94***	(0.363)
Owner.Code=122062521 × Wind GWh	-1.221***	(0.222)	-2.515***	(0.420)
Owner.Code=122062548 × Wind GWh	-1.871***	(0.192)	-3.279***	(0.361)
Owner.Code=122062550 × Wind GWh	-36.17***	(0.192)	-38.63***	(0.365)
Owner.Code=122062561 × Wind GWh	-3.990***	(0.193)	-3.966***	(0.363)
Owner.Code=122062564 × Wind GWh	-0.0728	(0.195)	-1.687***	(0.370)
Owner.Code=122062581 × Wind GWh	-6.078***	(0.202)	-7.241***	(0.384)
Owner.Code=122062590 × Wind GWh	-103.9***	(0.194)	-115.0***	(0.367)
Owner.Code=122062603 × Wind GWh	-2.036***	(0.191)	-4.147***	(0.360)
Owner.Code=122062624 × Wind GWh	-2.116***	(0.200)	-2.951***	(0.378)
Owner.Code=122062627 × Wind GWh	-0.582**	(0.195)	-2.103***	(0.369)
Owner.Code=122062642 × Wind GWh	-7.270***	(0.202)	-7.196***	(0.386)
Owner.Code=122062646 × Wind GWh	-1.131***	(0.195)	-2.560***	(0.370)
Owner.Code=122062647 × Wind GWh	-3.625***	(0.206)	-7.178***	(0.391)
Owner.Code=122062649 × Wind GWh	-14.34***	(0.204)	-15.39***	(0.390)
Owner.Code=125767546 × Wind GWh	-1.974***	(0.190)	-2.869***	(0.357)
Owner.Code=576468110 × Wind GWh	-61.28***	(0.193)	-66.09***	(0.366)
Owner.Code=576468116 × Wind GWh	-11.28***	(0.198)	-14.22***	(0.376)
Owner-Price-Year-Month-Hour Fixed Effects	Yes		Yes	
Controls for Demand	Yes		Yes	
Other Controls	Yes		Yes	
Peak	No		Yes	
Sum of Coeficients	-316.06		-378.86	
Observations	7,722,893		2,058,174	
R-squared	0.97		0.98	

Notes: Data comes from MISO Real Time Offer Market Reports January 1, 2014 to December 24, 2016. This sample is all offers by diverse market participants. Column (1) uses the full sample, while column (2) is only for peak hours, defined as 3pm to 8pm inclusive. Offer curves are are interpolated and defined at \$3 intervals between 0 and 60 USD. All unit level offers are aggregated to the market participant. One observation is the quantity offered by all unit owned by the same market participant at a given price for the hour. Sample includes all diverse market participants. All specifications include a fixed effect for the average quantity offered by the market participant at the price for a given month-hour, and control for demand. Other controls include daily temperature, daily natural gas price, hourly number of binding constraints, hourly shadow price of all constraints. Standard errors, in parenthesis, are clustered by month of sample and owner. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively for each hypothesis test. The hypothesis test for all coefficients is $H_0 : \beta = 0$ vs. $H_1 : \beta \neq 0$.

the degree to which market participants withhold their generation offer

$$\Delta CS_{comp} = \sum_t D_t(p) \frac{1}{\sum_o S'_{ot}(p) - d'_t(p)} dW_t \tag{11}$$

$$\Delta CS_{SFE} = \sum_t D_t(p) \frac{1 - (\sum_{o \in V} \theta_o)_t}{\sum_o S'_{ot}(p) - d'_t(p)} dW_t \tag{12}$$

$$\Delta CS_{obs} = \left[1 - \sum_{o \in V} \hat{\delta}_o \right] \sum_t D_t(p) \frac{1}{\sum_o S'_{ot}(p) - d'_t(p)} dW_t \tag{13}$$

I calculate the value of Equation 11, Equation 12, and Equation 13 using all hours between January 1st 2014 and December 24th 2016. I do this in two ways to account for import and exports of electricity within MISO. One uses net generation within MISO as a proxy for demand net of imports. The other considers total demand within MISO.

Table 6 presents all estimates of the total change in consumer surplus, as well as market revenue over the sample period. I normalized these totals to a value per person per year assuming 50 million people live within MISO's footprint.[26] The potential consumer surplus from increased renewable generation, according to Equation 11, is huge, seven to ten billion USD over three years, equivalent to 47 to 68 USD per person per year. This number is greatly diminished if diverse market participants withhold perfectly, as calculate by Equation 12. The total consumer surplus would be only 1.9 to 2.7 billion USD, or 13 to 18 USD per person per year. Using the observed withholding coefficients to calculate consumer surplus, as in Equation 13, the surplus per person per year is 32 to 46 USD, suggesting that observed withholding by diverse market participants reduces consumer surplus by 15 to 22 USD per person per year.

6 Conclusion

The increase in renewable generation capacity within the United States has created immense value by providing low marginal cost electricity. I first derive an analytical expression for how increased renewable generation should impact the price of electricity. I show the strategic response of conventional electricity generators to increased wind generation is an important factor to consider in

[26]This population estimate is my best guess given that 61 million individuals live in the states of Arkansas, Illinois, Indiana, Iowa, Louisiana, Michigan, Minnesota, Mississippi, Missouri, North Dakota, Wisconsin according to the 2016 US Census Bureau estimates.

Table 6: Impact of Curtailment on Consumer Surplus

	Demand Less Net Imports		MISO Demand	
	Total, Bil.USD	Annual USD/person	Total, Bil.USD	Annual USD/person
Revenue	58.70	393.93	55.33	371.34
ΔCS_{comp}, no curtail	6.96	46.71	10.09	67.75
$\Delta CS_{o}bs$, observed	4.76	31.95	6.90	46.34
ΔCS_{sfe}, full curtail	1.92	12.88	2.74	18.37
$\Delta CS_{comp} - \Delta CS_{obs}$	2.20	14.76	3.19	21.41
$\Delta CS_{comp} - \Delta CS_{sfe}$	5.04	33.84	7.36	49.38

Notes: Time period of interest is from January 1st, 2014 to December 24th, 2016. All calculations come from Equation 11, Equation 12, Equation 13. Revenue is the sum of Market MEC and market generation quantity in MWh for all hours. "Demand Less Net Imports" uses the analytical merit order effect and production quantity at the equilibrium where supply net of wind equals demand less net imports. "MISO Demand" uses the equilibrium where supply net of wind equals total demand within MISO. Bil. stands for billion. Annual per person calculations divides the total quantity by 2.98 years and 50 million people. This number is the authors best guess for the population within MISO's footprint based on the cumulative population of 61 million in the states of Arkansas, Illinois, Indiana, Iowa, Louisiana, Michigan, Minnesota, Mississippi, Missouri, North Dakota, Wisconsin according to the 2016 US Census Bureau estimates. All numbers are in nominal US dollars.

price formation. In particular, a supply function equilibrium model with horizontally integrated generating units predicts that diverse market participants will reduce their generation offer in response to an increase of their own wind generation. Using detailed data on supply and demand from 2014 to 2016 in MISO's wholesale electricity market, I quantify the expected price reduction under a model of perfect competition and a supply function equilibrium model with withholding.

I directly test for evidence of physical withholding by diverse market participants using month-of-sample by hour, price, owner fixed effects. Indeed, it is the diverse market participants that reduce the quantity offered, and they do it more in response to their own wind generation. This has important implications for consumer surplus and overall economic efficiency if this withholding leads to less efficient units having merit in the dispatch order. The analytical merit order effect I calculate and withholding coefficients I estimate imply increased renewable generation has the potential to increase consumer surplus by 47 to 68 USD per person per year, however observed withholding by diverse market participants reduces consumer surplus by 15 to 22 USD per person per year. This has implications for the market monitor in these wholesale electricity market, as increased renewable generation might be associated with anti-competitive behavior.

There are a number of policy implications that come from these results as well as avenues for future research. For one, the ownership of the renewable generation assets is not neutral to the incidence of consumer and producer surplus. Wind turbines and solar panels owner by diverse market participants participating in wholesale markets will not reduce the price of electricity by as much as the same assets owned by independent market participants or compensated by purchasing power agreements. Moving forward, it is important to quantify how renewable generation impacts producer surplus in these wholesale electricity markets. Producers can benefit from increased renewable generation because it reduces their fuel cost, or can be harmed if it decreases the price they receive. With accurate information on the cost of production, it would be straight forward to calculate producer surplus and compare them to my estimates of consumer surplus. Finally, this paper shows that wind generation might not be replacing the most inefficient generation units because of profit motives. There might be technical reasons for this as well. Better understanding why this might be the case can increase the value derived from renewable generation.

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A Appendix: Firm's incentives

Given the notation presented in section 2, I can characterize market participant o's profits at time t as

$$\Pi_o(S_o(p)) = p[S_o(p) + \theta_o W] - C_o(S_o(p)) \tag{14}$$

The optimal strategy employed by the owners of electricity generation assets depends on the uncertainty with respect to the market clearing price. As modeled there are two different forms of uncertainty (1) the quantity demanded, ε, and (2) the quantity of wind being produced ω. The first form of uncertainty, in conjunction with uncertainty over private forward contracts, has been considered by Hortacsu and Puller (2008); Mercadal (2015). The uncertainty in regards to wind is novel. I define a probability measure over the realizations of price for a given strategy for a particular market as follows:

$$\begin{aligned} H(p;S_o(p)) &= Pr(\hat{p} \leq p|S_o) \\ &= Pr(\sum_{j\neq o} S_j(p) + S_o(p) + w + \omega \geq d(p) + \varepsilon|S_o) \end{aligned} \tag{15}$$

Where the second inequality comes from the market clearing condition and the fact that a lower price is associated with an excess of supply. Using the profit definition with the probability measure, the market participant wants to maximize their expected profit:

$$\max_{S_o(p)} \int_{\underline{p}}^{\bar{p}} U\left[\Pi_o(S_o(p))\right] dH(p;S_o(p)) \tag{16}$$

We can rewrite $dH(p)$ as $H_p + H_S S'$ where the subscript denotes a partial derivative, and define $J \equiv U(\Pi)[H_p + H_S S']$. The first order condition for the Euler Lagrange solution is

$$J_S = \frac{\partial}{\partial p} J_{S'}$$

The left hand side can be expressed as

$$\begin{aligned} J_S =& U'(\Pi)\frac{\partial \Pi}{\partial S}\left[H_p + H_S S'\right] + U(\Pi)\left[H_{Sp} + H_{SS}S'\right] \\ =& U'(\Pi)\left[p - C'\right]\left[H_p + H_S S'\right] + U(\Pi)\left[H_{Sp} + H_{SS}S'\right] \end{aligned}$$

Then noting that, $J_{S'} = U(\Pi)H_S$, we can express the right hand side as

$$\begin{aligned} \frac{\partial}{\partial p} J_{S'} =& U'(\Pi)\frac{\partial \Pi}{\partial p} H_S + U(\Pi)\left[H_{Sp} + H_{SS}S'\right] \\ =& U'(\Pi)\left[S'p + S + \theta W - C'S'\right] H_S + U(\Pi)\left[H_{Sp} + H_{SS}S'\right] \end{aligned}$$

As a result, the Euler-Lagrange condition implies

$$\left[p - C'\right]\left[H_p + H_S S'\right] = \left[S'p + S + \theta W - C'S'\right] H_S$$

which can be simplified to

$$\left[p - C'\right] H_p = \left[S(p) + \theta W\right] H_S$$

Contextually, H_p is the density of prices in the spot market and H_S is the change in the price distribution when participant o increases it's supply offer.

We can isolate all the random terms as follows:

$$\begin{aligned}
H(p; S_o(p)) &= Pr(\hat{p} \leq p | S_o) \\
&= Pr(\sum_{j \neq o} S_j(p) + S_o + w + \omega \geq d(p) + \varepsilon | S_o) \\
&= Pr(\omega - \varepsilon \geq d(p) - \sum_{j \neq o} S_j(p) - S_o - w | S_o) \\
&= 1 - \Gamma\left[d(p) - \sum_{j \neq o} S_j(p) - S_o - w\right]
\end{aligned} \tag{17}$$

Where $\Gamma()$ is the cumulative density function for the random variable $\eta = \omega - \varepsilon$.

From this expression of the probability measure, we can derive

$$\begin{aligned}
H_S =& \Gamma'\left[d(p) - \sum_{j \neq o} S_j(p) - S_o - w\right] \\
H_p =& -\Gamma'\left[d(p) - \sum_{j \neq o} S_j(p) - S_o - w\right]\left(d'(p) - \sum_{j \neq o} S_j'(p)\right)
\end{aligned}$$

We can observe that the residual demand for any market participant is $RD(p) = d(p) + \varepsilon - \sum_{j \neq o} S_j(p) - w - \omega$ making $\frac{H_S}{H_p}$ an expression for the reciprocal of the slope of the residual demand. This provides an optimality condition that is related to the inverse elasticity pricing rule:

$$\left[p - C_o'(S_o(p))\right] = \left[S_o(p) + \theta_o W\right] \frac{-1}{RD'(p)} \tag{18}$$