Measuring the Impact of Wind Power: Output- vs. Capacity-based Subsidies*

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Abstract

We provide a comprehensive welfare assessment of the impact that wind power has had on the Spanish electricity market during the years 2009-2018. Using detailed hourly data on demand, production, prices, operational costs, and emissions, we provide estimates of the marginal and average impacts of wind on these welfare components. We also document how major market design changes can impact the dispatch of intermittent resources. We exploit a policy change that shifted output-based wind subsidies to capacity-based subsidies to show how such policies can significantly impact the operational effects of wind. We find that capacity-based subsidies removed the presence of zero and near-zero marginal prices and reduced congestion and adjustment costs in the market. However, it also led to a lower utilization of wind generation, reducing the environmental benefits of the installed wind capacity. In net, we find that consumers were worse off with the change, traditional producers benefited, and the overall economic surplus increased due to the reduction in the costs of intermittency.

KEYWORDS: electricity markets, energy transition, intermittency, wind power.

JEL classification codes: Q40, Q42, Q52.

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1 Introduction

Following the advice of climate scientists, governments around the world are utilizing a variety of policies to accelerate the shift to renewable energy sources. Spain, for one, has passed numerous policies in the past ten years to incentivize the rapid installation of wind farms, allowing wind's average hourly generation to satisfy nearly 20% of electricity demand from 2009-2018. However, although the deployment of renewables is essential to combat climate change, their non-dispatchable nature leads to several complications within the grid. There is concern that as the use of intermittent renewables rises, so too will the costs incurred by electricity producers. These integration costs affect the social value of wind that is necessary to design the optimal generation mix (Joskow, 2019).

Using high-frequency data from the Spanish electricity market, we quantify the average and marginal impact of wind on several key components of welfare in the Spanish electricity market during a decade. The detailed available data, as well as the widespread integration of wind, makes the Spanish electricity market a unique opportunity to evaluate the impact of wind at high generation levels. Furthermore, Spain exists in relative isolation, in conjunction with Portugal, from the rest of the European electricity market. Therefore, in the upper tail of wind generation, when wind can satisfy up to 70% of electricity demand, the Spanish electricity market has limited ability to export, making intermittency a potentially larger challenge. Finally, Spain has experienced defined and well-documented shifts in incentives for wind producers, thus allowing us to explore policy impacts.

We exploit the exogenous variation in hourly wind forecasts to estimate the impact of wind on intermittency costs, prices, and emissions using a ten-year panel (2009-2018). We consider both linear and semi-parametric specifications, and confirm that our results are robust to the use of different control variables and time fixed effects. Our baseline estimates show that increasing levels of wind increases system costs by about 0.2 EUR/MWh for each GWh of wind, diminishing wind producer profits and consumers' benefits when compared to an approach that ignores the costs of intermittency. However, we find that such increase in operational costs is not exponentially growing in the level of wind. Given the multi-faceted effects of wind, we quantify its average impact across our ten year panel on several key aspects of welfare. We find that for consumer surplus, the decreasing price of wind outweighs the negative cost associated with paying for subsidies. For producer surplus, the combined positive effect of government subsidies and a decrease in marginal cost outweighs the decrease in prices for wind producers, and hurts traditional producers.

To get at the overall welfare effects, we consider a range of values for the investment costs of wind farms as well as the environmental benefits from the emissions reductions derived from increased wind production. We find that at 50 EUR/MWh of investment costs, the value of emissions reductions to lead to positive welfare is around 30 EUR/ton CO2. If instead the cost of investment is 80 EUR/MWh, the threshold value is around 130 EUR/ton CO2. Given the high need for decarbonization and recent updates in the social cost of carbon (Newell, Pizer, and Prest, Newell et al.; Bueb et al., 2019), we conclude that wind production improved overall welfare for plausible values of the investment cost of wind and the social cost of carbon. Furthermore, given that today's investment costs are on the lower range of our considered values, the cost-benefit analysis of renewable subsidies is very favorable going forward.

An important component of our welfare evaluation is the impact of wind on the system-wide costs of operating the grid. We explore to which extent the impact of wind on these costs has changed over time, and to which extent such changes can be associated to explicit market design rules. In particular, we exploit a regulatory change in June 2014 that transitioned wind subsidies from marginal subsidies, which were added to the wholesale price of electricity or implemented as a feed-in tariff, to eminently a payment for installed capacity, subject to availability requirements. This regulatory change reduced the incentives for wind producers to generate during high-wind conditions, leading to lower emissions reductions per MW of installed capacity. However, it also avoided inefficient utilization of wind farms in days of excess supply. From a distributional point of view, the change benefited traditional producers at the expense of consumers through higher wholesale prices. However, it also reduced the congestion and adjustment costs in the market by avoiding zero price bidding incentivized by the output-based subsidies. In net, the reduction in intermittency costs drove the impacts of the policy rather than the reduction in wind output, thus leading to an increase in total welfare.

We highlight two important takeaways. First, wind generation during this period contributed positively to welfare, benefiting consumers, wind producers, and climate goals under reasonable parameters. Second, market design can serve as a way to actively alleviate some of the concerns regarding wind intermittency. We find that a substantive change in market design moving to capacity-based subsidies from output-based subsidies, which distorted wholesale market prices, contributed to a reduction in the operational costs of accommodating very high-levels of wind into the grid.

Related literature As our paper evaluates the impact of wind and wind intermittency on multiple components of welfare, we reviewed several strands of literature examining wind's impact on different market outcomes. First, we reviewed the economics literature related to emissions offsets due to wind. (Cullen (2013), Novan (2015), Kaffine et al. (2013), Callaway et al. (2015), Siler-Evans et al. (2012) and Sexton et al. (2021) focus on the United States, and examine substitution patterns between renewable sources and traditional producers. They conclude that pollution savings, and their relative value to renewable subsidies, depend on the region, the time of day, and the generational mix. Kaffine and McBee (2018), Gutierrez-Martin et al. (2013), and Dorsey-Palmateer (2019) examine how fossil fuel cycling and inconsistent ramping up and down of power impacts emissions offsets. The first two sources find that such side effects of intermittency cause a reduction in emissions savings, whereas Dorsey-Palmateer (2019) concludes that shifts in the generational mix caused by intermittency increase emissions savings.

Next, we examined the literature investigating the impact of wind on market prices. Both Bushnell and Novan (2018) (California) and Gelabert et al. (2011) (Spain) find that overall, renewables decrease electricity prices. However, Bushnell and Novan (2018) determines that at shoulder hours, solar power's overall impact on prices is positive, due to the ramping up and down of traditional electricity sources, which they link to operational costs of ramping. Gelabert et al. (2011) finds consistent negative impacts of wind on prices, but notes that the effect varies from year to year, and was on a diminishing trend.

Third, we summarize the literature investigating the impact of wind on system costs. Gross and Heptonstall (2008), Swider and Weber (2007), Hirth et al. (2015), Milligan et al. (2011), and Joskow (2011) develop a baseline for understanding the topic via modeling, literature reviews, and brisk calculations. Gowrisankaran et al. (2016) and Batalla-Bejerano and Trujillo-Baute (2016) conduct research more relevant to this paper on the impacts of renewable intermittency on system costs. Batalla-Bejerano and Trujillo-Baute (2016) focus their investigation on Spain from 2011 to 2014, and find that intermittency increases system costs, but the use of flexible generators can partially offset this effect.

Furthermore, we investigate the literature surrounding the welfare impacts of wind power. Liski and Vehvilinen (2020) look at the welfare impacts in the Nordic market, where there is a relatively larger share of renewables and energy storage opportunities. They find that, due to falling electricity prices, consumer surplus rises sufficiently to cover the cost of subsidies for renewables. Abrell et al. (2019) evaluate the welfare impacts of renewables in Germany and Spain. Specifically for Spanish wind power, they find that the cost for reducing 1 ton of CO2 through subsidies ranges from 82-258 EUR, with producers losing and consumers benefiting.

Finally, there are two existing papers that evaluate a shift in subsidy payments similar to our policy change of interest. Aldy et al. (2018) uses a natural experiment in the US to compare the performance of wind outcomes in a setting with investment-based vs. output-based subsidies. They find that investment subsidies reduce wind output by 10-20% and are less cost effective than output-based subsidies. We find that capacity-based subsidies similarly decrease output, but we identify such reduction as occurring in very high-wind hours. Precisely for this reason, and different than in their work, we find that capacity-based subsidies are more efficient as they avoid very low distorted day-ahead market prices in days with excess surplus of wind. This policy change is also studied by Johnston (2019), with a focus on how the tax treatment of the different subsidy mechanisms affects investment. A key difference between the policy change of their focus and ours is that the subsidy mechanism was specific to each wind farm in the United States case, whereas our policy change affected the existing fleet at a moment in which the expansion of new wind power was no longer driven via a subsidy policy. Therefore, the investment channel is not relevant in our setting.

Our paper is unique across this literature in that it dissects a variety of market outcomes to determine the non-linear impact of wind generation on several welfare components, while attempting to isolate for specific intermittency effects. We find that wind generation has a negative impact on system costs, which drives welfare effects when a change in the subsidy policy is introduced.

The remainder of this paper is structured as follows. In Section 2, we provide a background in the Spanish electricity market structure and its regulations across the sample period. Additionally, we describe the theoretical basis behind our intermittency and welfare analyses, and we describe our data sources with summary statistics. In Section 3, we analyze the relation between wind generation and a variety of market outcomes using a regression approach. In Section 4, we take a stock of the evolution of prices, costs, and emissions, to assess the overall welfare benefits and costs from wind power, with a focus on the impacts of the transition from output-based to capacity-based subsidies. Section 5 concludes.

2 Background and policy context

This section provides background about the main characteristics of wind energy in Spain and about the market design of the Iberian Electricity Market.

2.1 Market organization

The Iberian Electricity Market is centrally organized in a day-ahead market and up to seven intraday or real-time markets.[1] In the day-ahead market, producers and consumers submit their supply and demand bids for each of the 24 hours of a delivery day, and production for each hour is auctioned simultaneously using a uniform rule, setting a marginal price of electricity for each hour of the day. The day-ahead plans for roughly all expected electricity, whereas sequential markets allow for re-trading. Moreover, the electricity market includes other markets where producers participate adjusting production or providing reserves to ensure security and reliability of supply at all times.

There are three additional balancing markets that ensure that the grid can be operated in a feasible manner, e.g., to solve congestion problems or ensure reliability constraints, which can increase the costs of procuring electricity. Approximately 8.8% of total scheduled energy is traded in those balancing markets. The restrictions market refers to the market that solves constraints in the electricity network such as congestion or auxiliary energy to account for the intermittency of renewable plants. This market takes place after the day-ahead and intra-day markets. The

[1] See Ito and Reguant (2016) for a thorough description of these markets.

aim of insurance markets is to provide reserves or back-up capacity to respond to deviations in demand or production. In these markets, which are specific to different types of reliability and back-up offerings, firms offer their power plants to provide these services and get compensated on an individual basis. The deviations market solves imbalances between supply and demand between an intra-day market and delivery. These imbalances are normally due to deviations in renewable generation or demand, or significant failures in plants. The costs of each of these markets are determined according to the need of these services on pay-as-bid auctions where plants submit offer curves to re-adjust their position.

Final consumers pay for most of these costs as a surcharge in their cost per purchased MWh. However, deviation costs due to last-minute wind changes are paid by wind farms, and determined by the costs of the deviations market. Wind farms need to pay the missing generation, if they fail to produced what they had scheduled, or get a payment for their surplus energy at lower prices than in the day-ahead market if they happen to produce in excess. In both cases, shortfall or surplus deviations are effectively penalized when compared to scheduling wind generation more accurately.

In our analysis, we explicitly separate system costs paid by consumers vs. those costs paid by wind farms, to appropriately understand the distributional implications of wind intermittency. We define "system costs" as those paid by consumers as an adder to the final cost of electricity.[2] Within the system costs paid by consumers, we also consider three broad categories: (i) congestion costs, which include the reshuffling costs after the day-ahead and intra-day markets, (ii) insurance services (which include reserves and secondary regulation, among others), and (iii) deviation costs, meant to cover last minute deviations between production and demand, as explained above. Separately, we consider the deviations costs paid directly by wind farms, which affect their profitability and are not passed-through to consumers as an adder.

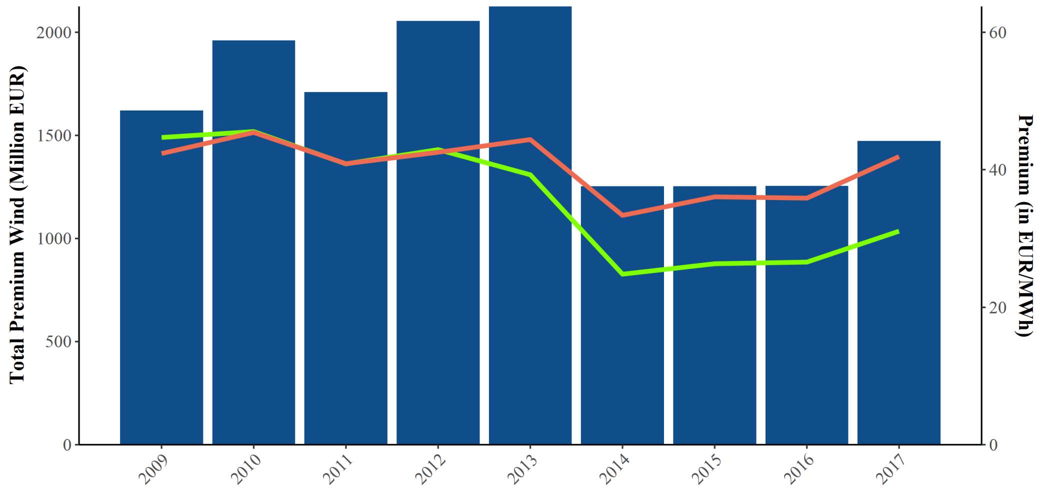
2.2 Regulation

Environmental regulation together with government subsidies and policies have encouraged investment in renewable energy in Spain over the last fifteen years. Renewable capacity in Spain experienced a considerable increase since 2005 motivated by feed-in-tariffs and capacity payments. Only combined cycle power increased since 2002, whereas the rest of traditional technologies remained fairly constant over time. Nowadays, renewable capacity accounts for approximately 25% of all generation in Spain and wind capacity alone accounts for 19% overall.

Regulation of renewable power in the Spanish electricity market has changed significantly in the last twenty years. In the beginning, regulation promoted investment in renewable capacity through output-based subsidies. In particular, renewable producers could opt for two pricing schemes since

[2] This nomenclature follows that of the grid operator, who refers to the costs of these additional markets, which are prorated to the price per MWh of the demand side, as "costes del sistema."

Figure 1: Total Premium and Subsidies for Wind Energy in Spain



Notes: This figure shows the total premiums paid to wind energy in the Spanish electricity market (in mEUR) and the implied subsidies (in EUR/MWh). The red line shows total subsidy remuneration divided by subsidized wind production while the green line shows total subsidy remuneration divided by all wind production, regardless of its subsidy status. Source: Comisión Nacional de la Energía (2018).

2007 (a) Feed-in-Premium (FiP), or (b) Feed-in-Tariff (FiT). Under option (a), producers sold their electricity in the electricity market and their price would be determined by the market price plus a premium payment. Under option (b) or FiT, producers had to offer all their production at a zero price in exchange of a regulated compensation invariable for all scheduling periods. These subsidies encouraged a significant increase of wind production from 5.7% of total electricity generation in 2004 to 18.9% 2014.[3] This increase in participation pushed market prices down in the day-ahead market as wind plants offered their energy at zero or near-zero prices. Additionally, wind's intermittent nature required an increasing utilization of adjustment markets where additional, reliable plants guarantee a fast response to changes in wind production with respect to forecast. The cost of these additional services went up as wind participation increased.

The increase in costs of subsidizing renewable technology, due to rising adjustment costs, as well as the decreases in price paid by consumers, contributed to a growing electricity debt that motivated a turn in regulation. The debt arose due to mismatches between the revenues obtained from consumers compared to the actual costs incurred by the electricity system and the transferred subsidies. Figure 1 shows the rapid increase in total wind subsidies paid by the Spanish government up to 2013. Wind farms received an average subsidy of approximately 45 EUR/MWh produced between 2009 and 2013 compared to an average subsidy of 30 EUR/MWh produced between 2014 and 2017.

[3] https://ourworldindata.org/explorers/energy

Subsequent regulation hence focused on eliminating these output-based subsidies and designing a new subsidy scheme to provide an additional economic compensation for renewable energy at lower costs. The Spanish government implemented several regulations between 2012 and 2014 to decrease the "electricity debt". The regulations also promoted the improvement of operational procedures to better integrate wind into the market. Table A.1 in the Appendix presents the most relevant regulations during our sample period.

The first regulation in 2012 suppressed the economic incentives for new renewable production facilities, which explains why renewable energy stopped growing after 2012. The second regulation, in February 2013, eliminated the FiP pricing scheme. Under this regulation all producers under the FiP scheme were moved to the FiT pricing scheme. In July 2013, the government further eliminated the FiT pricing scheme, although the new pricing scheme was not implemented until June 2014. These new regulations affected the arbitrage incentives for wind plants illustrated in (Ito and Reguant, 2016).

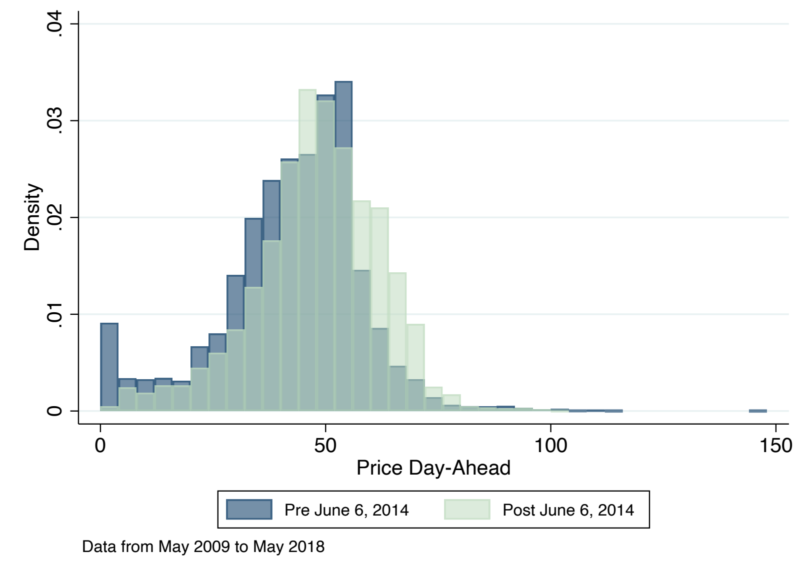
In June 2014, the Government implemented a new pricing scheme where renewable producers were compensated by installed capacity rather than produced electricity. This new compensation was based on a capacity payment to compensate investment costs not recovered through the market, and a production payment to provide investment incentives by reducing production costs. Both components were independent of the actual revenues or investment costs of the producers. The new pricing scheme applied to facilities that had not recovered the investment costs previously (mostly capacity installed after 2004). Around 51% of the installed wind capacity effectively received subsidies of less than 20 EUR/MWh that were not enough to cover marginal costs and hence were exposed to market prices.[4] This regulation in addition stated the possibility of renewable sources' participation in adjustment markets, although their participation effectively started only in February 2016.

One important feature of the June 2014 regulatory change is that most wind generation stopped having marginal subsidies proportional to production, and instead were offered subsidies to investment (subject to minimum availability requirements to avoid perverse incentives on maintenance). This change had a very significant impact on the occurrence of zero prices in the day-ahead market, as shown in Figure 2a. It also effectively removed the incentives of wind farms to offer their output in the market in situations of wind oversupply. Surprisingly, we find that the policy did not lead to significant curtailment of wind at high-levels of generation, as shown in Figure 2b.

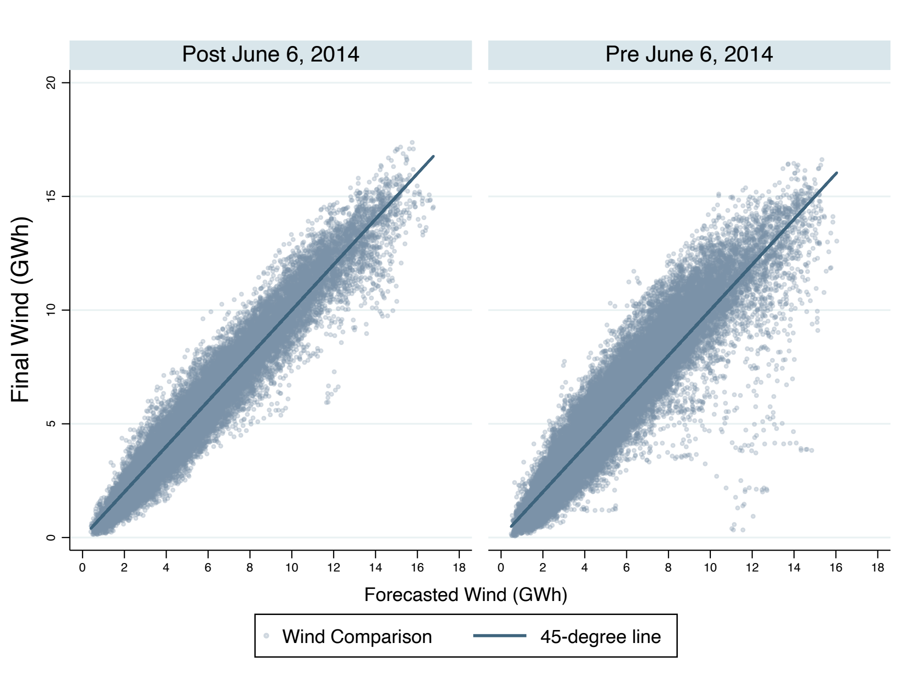
We focus on the change in June 2014 because, empirically, it seems to be the one that has the most substantial impact on the system costs of integrating wind via the elimination of zero prices. We provide evidence that the economic channels expected to play a role in this policy, are borne by the data. However, it is important to keep in mind other measures undertaken by the regulator can also affect the welfare implications of wind power.

[4] Page 25, https://www.aeeolica.org/uploads/AEE__ANUARIO_2015_web.pdf.

Figure 2: Price and wind outcomes before and after the 2014 policy change



(a) Day-ahead marginal prices before and after policy change



(b) Wind productions vs. wind forecast before and after policy change

Notes: Going from production-based to capacity-based subsidies removes the incentives to bid all wind production at very low prices. The policy change reduced the occurrence of zero prices in the wholesale electricity market, as shown in Panel (a). The policy change did not seem to lead to additional wind curtailment in hours of high wind production, as shown in Panel (b).

2.3 Data

We construct a dataset using publicly available data from the system operator, Red Eléctrica de España (REE), and the the Iberian electricity Market Operator (OMIE). The final dataset includes planning and production outcomes from the system operator at the hourly level. More precisely, it incorporates aggregate demand and supply from each type of generation, market clearing prices, emissions, demand forecasts, and wind forecasts. One of the main advantages of this dataset is that forecasts are observed hourly and for up to 48 hours before that hour is realized. This allows us to construct different variables based on these forecasts to compare to actual demand or production delivered. Another advantage is that the data have detailed accounting of reliability, congestion, and other system costs, allowing us to measure the impact of wind on these different components. Finally, the addition of market prices and emissions expands the scope of this paper to include a full welfare analysis.

Table 1 provides summary statistics for the main variables of interest. We use data from January 2009 to December 2018. The average wind delivered in that time period was $5,290$ MWh (with a median value of $4,724$ MWh), or approximately 18.5% (16.4%) of actual demand. Wind deviations from the last market taking place for a given hour are on average 147.68 MWh and vary significantly across different hours. In this sample, average price is 44.83 EUR/MWh and average system costs are 3.99 EUR/MWh. These costs are the sum of restrictions, insurance, and deviations costs, where restrictions explain the majority of system costs.

We supplement the data from the REE and OMIE with several other sources to account for a variety of additional variables. First, we obtained data on historical natural gas prices from Bloomberg Markets.[5] Prior to March 2010 we utilized the British Virtual Gas Hub Spot Price, after August 2014 we used the Netherlands TTF Spot Price, and in the dates between we used an average of the two. Second, we obtained historical weather data on hourly temperature, humidity, pressure, and dew point at a variety of airports across Spain from the Wunderground databases[6] (prior to 2017) and the Tutiempo databases[7]— (2017 and 2018). Finally, we downloaded data on daily EU-ETS carbon pricing from the Carbon Price Viewer webpage on the Sandbag Smarter Climate Policy Website.[8]

In addition to detailed market outcomes data, we construct two variables to summarize intermittency: volatility and uncertainty. We define volatility as the changes in delivered wind production between different hours of the day, and across different days. We compute volatility as the standard deviation in delivered wind for rolling intervals of 6, 12, and 24 hours. Figure A.1a shows the distribution of the standard deviation in wind delivered for those different time intervals. One can

[5] https://www.bloomberg.com/energy

[6] https://www.wunderground.com/history

[7] https://www.tutiempo.net/registros/

[8] https://sandbag.be/index.php/carbon-price-viewer/

Table 1: Summary Statistics

	Summary Mean	SD	P25	P50	P75
Actual Demand (GWh)	28.66	4.84	24.51	28.83	32.34
Wind Forecast (GWh)	5.29	2.96	2.97	4.7	7.06
Solar production (GWh)	.82	1.08	0	.05	1.65
Price DA (EUR/MWh)	44.83	15.49	36.88	46.5	54.3
Total System Cost (EUR/MWh)	3.97	3.17	1.96	3.22	5.07
Restrictions Cost (EUR/MWh)	2.56	2.38	1.04	2.03	3.37
Insurance Cost (Euro/MWh)	.3	.79	0	.12	.4
Deviations Cost (EUR/MWh)	1.14	1.39	.43	.76	1.35
CO2 Emissions (tCO2)	7087.11	2771.43	4823.5	7204.52	9222.67

Notes: Price DA is the price at the day-ahead market. The variable "Operational Cost" is the sum of all other costs (restrictions, insurance, and deviations costs). $N = 78,730$.

see that, in the span of 24 hours, it is common for wind to have a standard deviation of around one GWh, and it is not uncommon to have standard deviations above two, which is substantial given average wind production of 5.30 GWh.

We define uncertainty as the difference between forecasted and actual generation. We compute uncertainty as the standard deviation of the differences between forecasted and delivered wind in the periods leading to the time of delivery. We exploit the fact that we observe predicted wind at different intervals: 36 hours in advance, 35 hours in advance, etc. Therefore, we observe how uncertainty in the forecasts is evolving over time and can compute the standard deviation in such forecasts. Figure A.1b shows the distribution of uncertainty when we consider forecasts up to 6, 12, 24 and 36 hours in advance to compute the standard deviation. The measures show that uncertainty is reduced as the time of delivery approaches, but there is still substantial uncertainty left even six hours in advance, with a mode around 150-200 MWh. This implies that the forecast of wind for a given hour can fluctuate in the order of 150 MWh even six hours close to delivery, and some days the forecasts can fluctuate by 500 MWh (approximately 10% of wind generation) or more.

3 Quantifying the impact of wind

We empirically investigate the impact that wind power has had in the operations of the Iberian electricity market. Our goal is to characterize the impact that wind generation has to several market outcomes, such as prices, system costs, and carbon dioxide emissions, putting special emphasis on the role of intermittency in explaining the effects. We also explore the temporal evolution of these impacts. We first focus on the impacts to system costs paid by consumers, such as congestion payments and reliability services, which are very directly linked to intermittency. We then evaluate other market outcomes that are relevant for a comprehensive welfare evaluation (prices, wind revenues, and emissions).

3.1 System costs

Our goal is to estimate the fraction of system costs that are explained by wind production and intermittency. Wind production and intermittency affect restrictions markets causing congestion, increasing the need for back-up capacity in specific nodes of the grid. Changes in forecasts affect firms' positions in intra-day markets, causing over or under production in the grid. Wind production has an impact on insurance markets due to the need for higher reserves to accommodate deviations in production working against deviations in system demand.

We first investigate the average effect of wind generation on all system costs (in EUR/MWh) using the following specification:[9]

$$Y_t = \beta_0 + \beta_1 W_t + \gamma X_t + \epsilon_t \ , \tag{1}$$

where Y_t refers to the outcome of interest, W_t is the forecasted wind in the market, X_t includes control variables, and ϵ_t is the error term. The coefficient of interest is β_1 and represents the marginal effect of a GWh increase in wind on Y_t. In this as well as future regressions, control variables include daily natural gas prices, as well as hourly forecasted demand, temperature, temperature squared, dew point, and photovoltaic generation.

We estimate equation (1) using OLS and clustering standard errors at the month of sample level. We exploit the exogenous variation in wind output and intermittency to identify its effects on the outcomes of interest. Furthermore, we control for demand forecasts, solar production, and time fixed effects that might impact the evolution of these variables.

Table 2 presents the baseline results for the impact of wind on total system costs. We confirm that wind generation tends to increase system costs. For an additional GWh of forecasted wind generation, our results suggests that system costs go up by about 0.17 to 0.23 EUR/MWh compared to an average of 3.66 EUR/MWh. The results are robust to the inclusion of several relevant controls, such as natural gas prices, which fluctuate substantially during this period, and weather indicators. Intuitively, the price of natural gas also contributes positively to system costs, which is intuitive due to the role of gas power plants at providing these services, although the effects are noisily measured due to the inclusion of substantial fixed effects (interactions of month, year, and hour).

[9] The same patterns arise if we focus on costs in thousands of dollars, instead. The measure in EUR/MWh facilitates a direct comparison with market prices, which are in EUR/MWh.

Table 2: Marginal impacts of wind on system costs

VARIABLES	(1)	(2)	(3)	(4)
Forecasted wind (GWh)	0.198	0.197	0.199	0.194
	(0.0168)	(0.0168)	(0.0166)	(0.0168)
Forecasted demand (GWh)	-0.156	-0.157	-0.159	-0.159
	(0.0199)	(0.0197)	(0.0197)	(0.0197)
Solar production (GWh)	0.0152	0.0244	0.0525	-0.0166
	(0.0725)	(0.0707)	(0.0695)	(0.0673)
NG price (EUR/MWh)		0.0923	0.0877	0.0862
		(0.0700)	(0.0694)	(0.0693)
Mean temperature (F)			-0.0358	-0.0151
			(0.0358)	(0.0375)
Sq. mean temp. (F/1000)			0.175	0.0706
			(0.271)	(0.277)
Mean dew point (F)				-0.00978
				(0.00700)
Observations	78,706	78,706	78,706	78,706
R-squared	0.550	0.551	0.551	0.551

Notes: Standard errors clustered at the month of sample. All regressions include fixed effects of month-of-sample interacted with day of the week and hour.

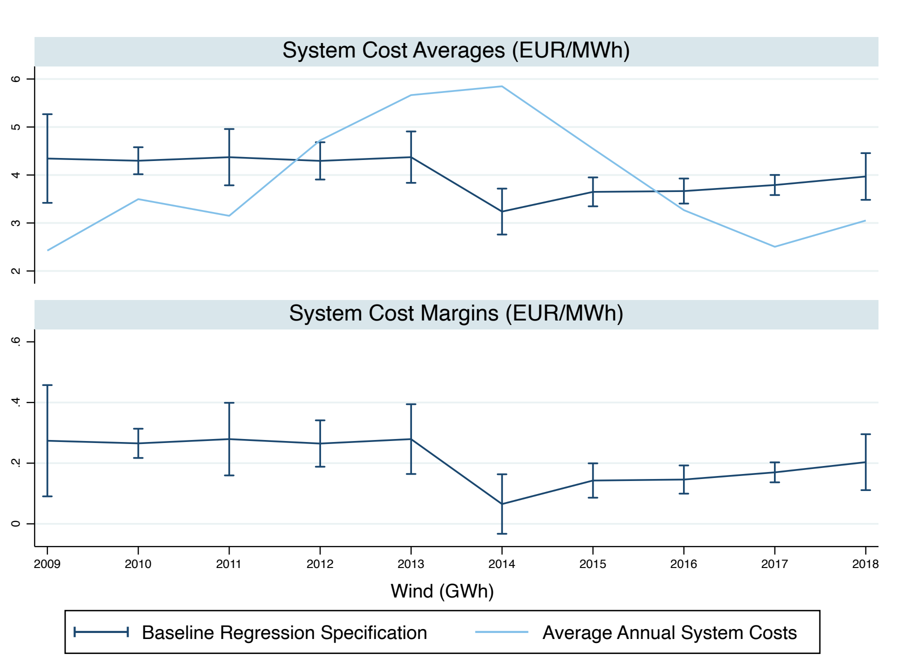
Sensitivity to fixed effects Month-of-sample and year fixed effects account for seasonal variations and wind capacity expansions over time. In Spain, the expansion in wind power mostly preceded our sample of study. That said, we examine the impact of structural changes over time following Bushnell and Novan (2018) by considering a specification without year fixed effects. Additionally, for complete robustness, we evaluate the impact of all combinations of year, month, and hourly fixed effects on our variable of interest, as well as the coefficients attached to solar production and demand forecast.

Table A.2 in the Appendix shows the results of this analysis. In our context, and given the ample variation in wind production, we find that the inclusion of fixed effects does not substantially affect the results. From our central estimate of 0.20 EUR/MWh, we find that including only year fixed effects leads to an estimate of 0.215 EUR/MWh. Removing the year fixed effects leads to a larger impact of wind on system costs, at 0.238 EUR/MWh. Although not explicitly shown in Table A.2, including additional fixed effects (month-of-sample interacted with day-of-week) leads to similar estimates, all of which range 0.174-0.238 EUR/MWh. We find that the inclusion of hourly fixed effects is important to control for predictable fluctuations of market conditions (and thus, system costs) that might not be captured by our controls. These controls impact the effect of solar power on system costs, but not the effect of wind. This is to be expected, as solar power is much more predictable and is very correlated with hourly seasonality. In the absence of hourly fixed effects, solar is negatively correlated with system costs due to its zero production in peak evening times. The estimates on forecasted demand are also substantially impacted for the same reason. Wind effects, on the contrary, are very robust to fixed effects due the inherent randomness of wind output, which is not true for electricity demand and solar generation.

Annual effects To further examine the structural changes of wind over time, we estimate equation (1) with year interaction terms attached to the coefficient of interest. This allows us to explore whether the impacts of wind are becoming more or less salient over time for the same level of wind output.

Figure 3 depicts the annual marginal and average effects of wind on system costs via our baseline regression. For reference, the mean annual system cost is included in the upper panel. The results do not indicate a consistent increasing or decreasing trend in the marginal effect of wind on system costs over the sample period. Instead, there is a sharp decrease in the marginal and average effects in 2014, followed by a gradual, partial recovery in the remaining years. The marginal and average effects dropped from their maximum values in the sample (0.30 EUR/MWh and 4.51 EUR/MWh, respectively) to their minimum values (.06 EUR/MWh and 3.25 EUR/MWh, respectively), while mean system costs continued to rise. This sharp decline in the cost effect occurs in conjunction with the June 2014 policy change described in Section 2. The policy eliminated most marginal incentives for wind producers, thus decreasing the number of upper tail wind generation occurrences coupled

Figure 3: Annual Average and Marginal System Cost Effects



Notes: A look at annual marginal and average effects of wind on system costs based on equation (1). Mean annual cost variation predicted by wind holding the impact of other variables at their average also included in the upper panel for reference.

with lower tail price occurrences. This shift in incentives gives ground to the policy change being a main driver of the prominent and sudden decrease in system costs in 2014 illustrated in Figure 3.

Daily effects Although our focus is not on solar generation, whose production is modest in the Spanish electricity market, the hourly effects of photovoltaics are confounding as most of the intermittency impacts of solar happen in those hours in which solar is not operating (Bushnell and Novan, 2018). To circumvent this issue, we present the results of a daily version of equation (1) in Table A.3 in the Appendix. In this table, the dependant variable is total system costs in thousands of euros and the unit of observation is a day in our sample. We find that the marginal impact of wind power is consistent with our hourly estimates, with an effect of around 6,290 EUR of costs for each additional daily GWh of wind. Rescaling by average demand, this translates into an impact of around 0.22 EUR/MWh. We also find that solar power tends to increase the operational costs in the system, the same way that wind does, although these effects are very noisily estimated due to the lack of variation in solar generation within a month as well as the relatively modest levels of solar generation during our period of study. Daily demand leads to much more modest increases in system costs, and the sign can even revert after controlling for weather patterns, which are a big driver of electricity demand.

Wind endogeneity We use forecasted wind as our wind variable W_t for several reasons. First, market clearing procedures often depend on forecasted wind, rather than the (unknown) realized wind. Second, using forecasted wind circumvents the issue of endogeneity of final wind production, which might be impacted by curtailment and strategic behavior. Figure 2b shows evidence that indeed final wind production can reflect endogenous curtailment. As can be observed, realized wind can be low at high levels of forecasted wind production, which tends to be reflective of forced curtailment.

We explore in Table A.4 in the Appendix the sensitivity of our results to using final wind production as well as using wind forecast as an instrument to final wind production. One can see that the estimated impacts of wind either using forecasted wind or wind instrumented with forecasted wind are basically analogous. However, the impact of realized wind, without correcting for endogeneity, are somewhat smaller. The direction of the bias is intuitive. By using realized wind, we are attributing some days with operational challenges and curtailment to "low wind" observations. However, it is precisely the presence of wind that could have triggered these conditions. The instrument corrects for this bias.

Spline regressions Equation (1) assumes that the impact of wind is constant regardless of the level of generation. To explore the potential for non-linear impacts, we consider the following spline specification:

$$Y_t = \beta_0 + \sum_{q=1}^{5} \beta_q W_{qt} + \gamma X_t + \epsilon_t \ , \tag{2}$$

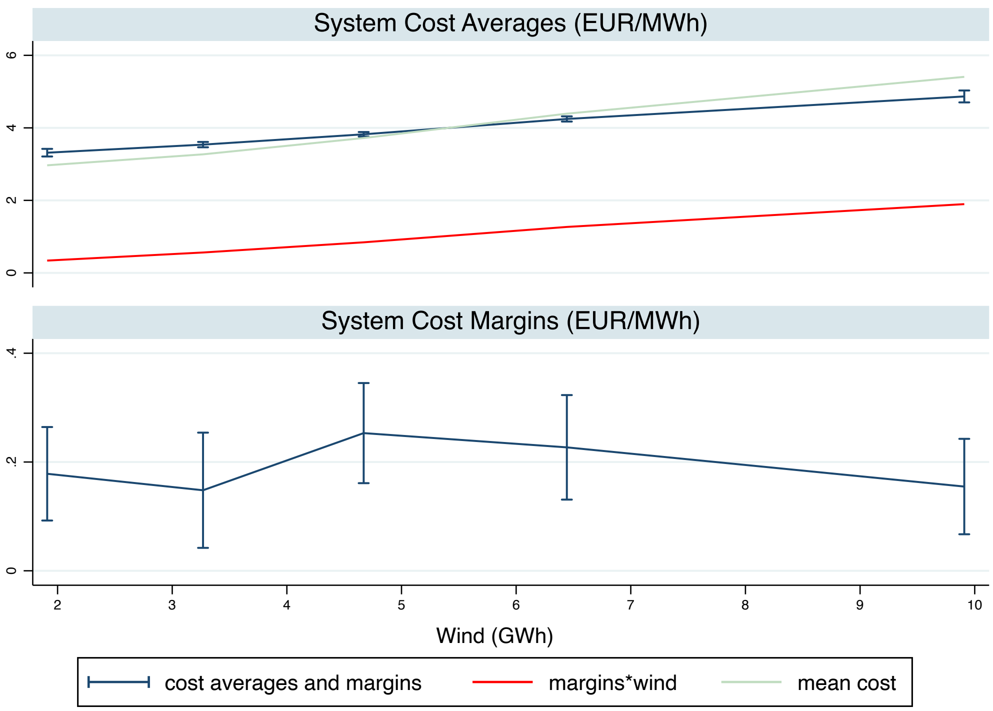
where W_{qt} are spline bins according to the quintiles of the wind variable.[10] This spline specification allows for flexible marginal effects from wind production while ensuring some consistency between the estimates of the different quintiles. The coefficients β_q provide the marginal impact from wind production on the outcome of interest.

We also use equation (2) to predict the average outcomes at different levels of wind, holding everything else constant. Additionally, we report the cumulative changes explained by wind by integrating out the effects implied by the coefficients β_q at different levels of wind.

Figure 4 shows the impacts of wind on total system costs. The upper panel shows that, on average, wind tends to increase system costs, which range from around 3.2 EUR/MWh at low levels of wind to over 5 EUR/MWh at higher levels of wind. We compare our predictions to the variation in the data, and find that the wind power, even after controlling for confounding factors, is estimated to explain most of the cost increases. We find that most of the correlation between system cost increases and wind production can be attributed to wind generation. This is shown by

[10] In particular, if a quantity falls within the first quintile, W_{1t} equals W_t and the rest are zero. If a quantity falls within the second quintile, W_{1t} equals to the first quintile, and W_{2t} equals the remainder output $W_t - W_{1t}$, and so forth.

Figure 4: Average Marginal Effects of Wind on System Costs



Notes: This figure shows the system cost impacts at different wind levels. The upper panel shows average system costs at different wind levels, whereas the lower panel shows the marginal total system cost impacts. For each wind quintile, we obtain the mean of wind forecast and use it on the x-axis.

comparing the "mean costs" observed in the data to those predicted by the wind quintiles. Overall, the incremental cost of wind generation on system costs is roughly 2 EUR/MWh at the highest quintile of production.

The lower panel focuses on the marginal slope implied by the spline function. We find that the marginal impacts of wind do not worsen with higher levels of wind generation. If anything, our results are more consistent with an inverted U-shape pattern. Marginal wind impacts on costs are relatively minor at low levels of wind, somewhat larger in middle ranges of production, and lower at the highest production levels. One possibility for this finding is that, at high levels of wind generation, many natural gas power plants are able and eager to participate in reliability markets, whereas at middle ranges of wind generation, the competition to provide reliability services might be less fierce.

Categories of system costs We further decompose the impacts of wind on system costs across restrictions, insurance, and deviations costs. Figure 5a shows the average marginal effects of wind on on the different components of operational costs using the definition in equation (2). The impact on deviations costs is very limited given that wind firms already internalize these costs. For higher levels of wind integration, marginal increases in wind have a higher impact on restrictions and insurance costs. To guarantee system reliability, wind plants need to be secured by surrounding power plants, which may create extra technical restrictions for higher integration levels. At the same time, the power system has to procure enough reserves to avoid insufficient generation. These reserve needs are more noticeable in days with higher levels of wind integration. Therefore, it is not surprising that deviations costs are marginally increasing as wind penetration expands.

Intermittency decomposition We further decompose the impact of the two sources of wind intermittency -volatility and uncertainty- on the outcomes of interest. We consider the following regression specification:

$$\mathrm{Y}_t = \lambda + \sum_{q=1}^{5} f_q(V_t, U_t) W_{qt} + \gamma X_t + \psi_t \ , \tag{3}$$

where V_t and U_t are volatility and uncertainty, respectively, $f_q(V_t, U_t)$ is a parametric form describing how volatility and intermittency impact the marginal effects of wind, and W_{qt} is the spline wind variable by quintile as defined in (2). Similar to equation (2), we also allow the coefficients to depend on the wind quintile as denoted by the index q.

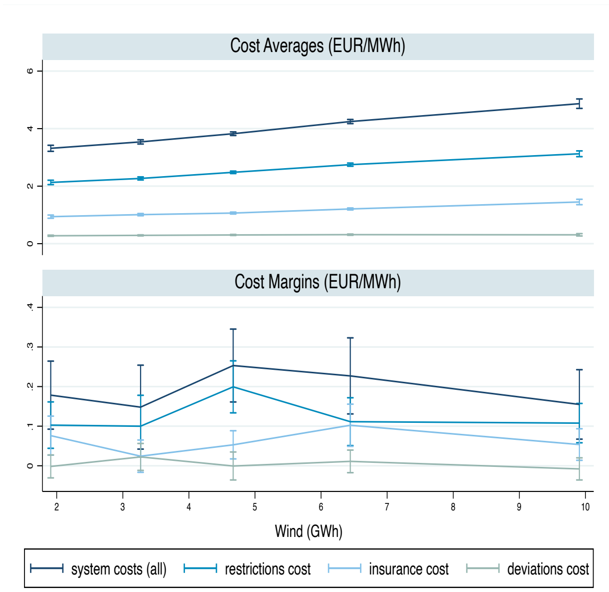
The function $f_q(V_t, U_t)$ allows system costs to be explained by wind through intermittency. That is, the interaction terms between wind and wind intermittency account for the fact that both volatility and uncertainty are a function of the level of wind and jointly determine system costs. We consider the following parsimonious specification at each quintile:

$$f_q(V_t, U_t) = \beta_{q0} + \beta_{q1} V_t + \beta_{q2} U_t, \tag{4}$$

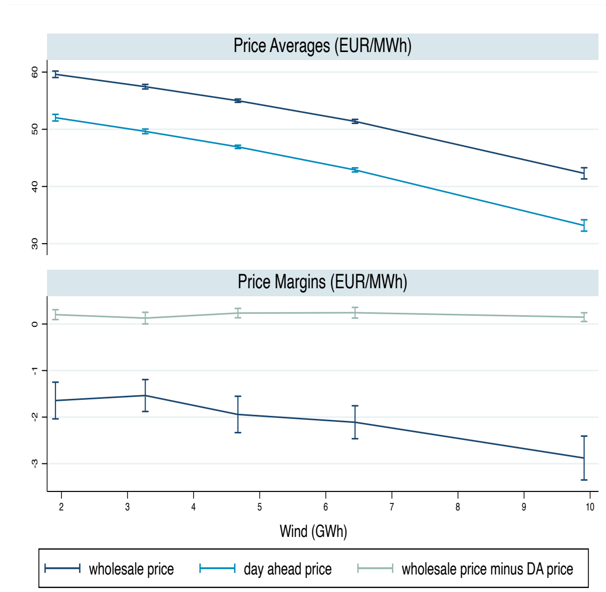
in which we allow the impacts of wind to be potentially different in days of high volatility or high uncertainty. To investigate the impact of volatility and uncertainty, we estimate Equation 3 combined with the above intermittency specification, then examine the marginal impact of wind at various percentiles of the volatility and uncertainty distribution. We use intermittency metrics using the definitions in Section 2 and a time period of 24 hours.

Figures A.2a and A.2b in the Appendix show the results of our intermittency analysis. In Figure A.2a, uncertainty seems to have no impact on cost margins and averages at low levels of wind, and only minimally increases the impact of wind on costs at high levels of wind. In Figure A.2b, the opposite it true: volatility has no impact on cost margins and averages at high levels of wind, and a minimal, positive impact at low levels of wind. However, the decomposition of wind's impact on cost through intermittency primarily highlights the fact that volatility and uncertainty investigated in conjunction with wind have only a minor impact on total system costs, due to the positive correlation between wind level and intermittency.

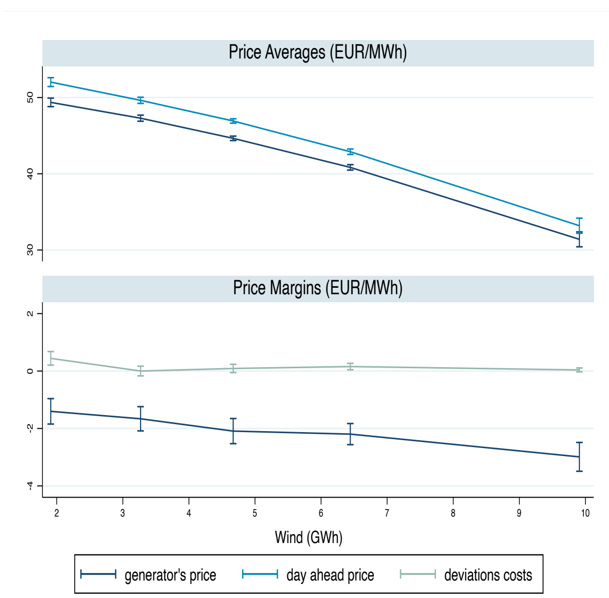
Figure 5: Impacts of Wind on Major Market Outcomes



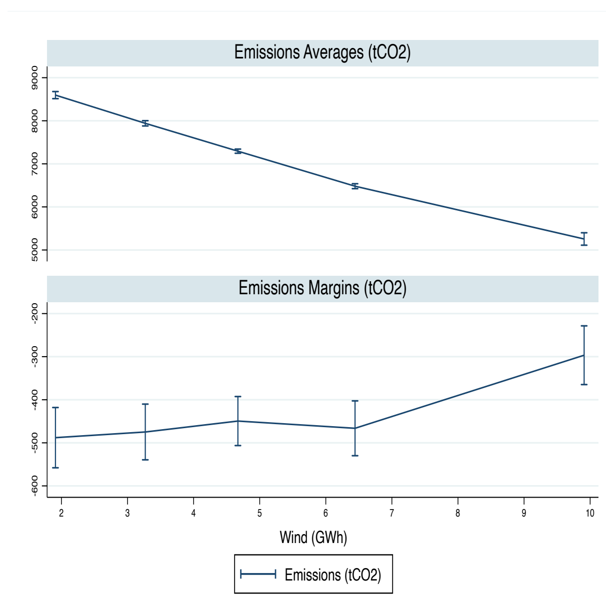
(a) System Costs



(b) Market prices



(c) Wind Profitability



(d) Emissions

Notes: This figure shows the impacts of wind on several market outcomes. For each wind quintile, we obtain the mean of wind forecast and use it on the x-axis.

That said, the overall impacts of volatility and uncertainty remain low, given that the biggest drivers of these factors are the levels of wind themselves. We therefore conclude that the overall level of production seems to be sufficient to capture the main impacts of wind.

3.2 Market prices

In addition to our analysis of system costs, we assess the impact of wind on market prices. It is well known that wind tends to reduce electricity market prices, due to its very low marginal cost of operation. To consider the broader market impacts of wind, we consider both the day-ahead market price of electricity as well as the final price of the wholesale electricity market, which includes prorated capacity and reliability costs as a markup. These different prices are indicated in Figure 5b as day ahead price and wholesale price, respectively.

The downward sloping average prices and the negative margins in Figure 5b are clear indications of wind's tendency to reduce electricity prices. However, the marginal difference between day-ahead and wholesale price is positive across the wind quintiles, suggesting that rising wind has a positive effect on the cost markup. This aligns with our earlier findings, which suggested that rising wind increases most cost components.

3.3 Wind revenues

In addition to market-wide costs, wind generators have to pay for the costs of their own last-minute deviations due to their intermittent nature. The price the generators receive, the navy line in the upper panel of Figure 5c, is therefore lower than the day-ahead market price. The teal line in the bottom panel of Figure 5c represents the marginal impact of wind on the difference between the two market price variables of interest, for which adjustment costs can proxy. We find that the costs of intermittency to wind farms are not significantly increasing with the level of wind, and if anything, they can be decreasing. The marginal impacts are small, and even insignificant at some wind levels. When the teal line is significant, the slightly positive margin implies that the difference between the generator price and the day-ahead price tends to decrease as output increases, which can be explained by the ability of wind farms to aggregate uncertainty in favorable wind conditions. This is likely due to the reduced variance in output (in relative terms) as wind output grows, as well as the availability of more idle thermal generators to compete during high wind hours.

3.4 Emissions

Our final market outcome of interest is carbon dioxide emissions. We expect that as wind generation increases, emissions in the Spanish Electricity Market will decrease, due to direct substitution of wind for fossil fuel energy sources. Figure 5d demonstrates this downward trend in CO2 emissions. We find that the marginal impact of an additional GWh of wind generation is around -500 tCO2 across most values of wind, which are consistent with marginal emissions rates of coal (around 0.90 tCO2/MWh) and natural gas generators (around 0.35 tCO2/MWh).[11] However, at high levels of wind, carbon emissions in the Spanish Electricity Market decrease on average by only 60% of the margin seen at low wind levels. The marginal effect of 1 GWh of wind decreases in absolute value to approximately -300 tCO2. This decline can be explained due to a decrease in the substitution of coal, wind curtailment as shown in Figure2b, as well as a corresponding increase in electricity exports. It is important to note that we do not quantify the emissions benefits of exports. If these exports offset high-emission sources in other countries, then at the global level, the marginal impacts on emissions reductions should be larger.

4 Welfare impacts of wind

The estimates from Section 3 can be used to understand the overall impacts of wind generation during our sample. We assess the economic impact of wind by using the following metric:

$$\text{Economic Surplus} = \text{Consumer Surplus} + \text{Producer Surplus} + \text{Emissions Benefits}.$$

To compute the change in consumer surplus, we evaluate the impact of wind on the electricity costs paid by consumers, i.e., the final price (including system costs) times demand, plus the cost of the subsidies.[12] We perform a spline regression analogous to equation (2) but with wholesale electricity consumer costs as the dependent variable. Thus, the marginal impact of wind on consumer surplus is identified at differing levels of wind. Similarly, to compute the change in producer surplus, we consider the semi-parametric impact on the price effect and the replacement effect, as described in Abrell et al. (2019), plus the subsidy payments. Due to the sensitivity of our analysis to the chosen levelized cost of wind, we independently identify the impacts on non-wind producer surplus, and wind producer surplus. For both non-wind and wind producers, the price effect, which is a negative change in producer revenues, is the decrease in the day-ahead prices times demand. Because wind farms incur penalties for deviation and therefore receive a slightly lower price, we utilize the change in the wind generator price times demand. The replacement effect, which is the change in producer surplus due to the substitution of high marginal cost electricity sources, is proxied for non-wind producers using the day-ahead price.[13] For wind producer surplus, the

[11] In a separate analysis utilizing generation sources as response variables, which can be provided upon request, we confirm that this is based on a substitution of primarily coal and combined cycle generation.

[12] It is important to note that we abstract away from the allocation of subsidy costs across different types of consumers (e.g., residential, commercial, and industrial). Such allocation of costs can affect the net gain from the policy of different types of consumers (Mastropietro, 2019; Reguant, 2019).

[13] The impact of wind on such a metric is $\frac{\partial p/\partial W}{2} + p$. We use the observed day-ahead price plus the change induced by wind to the market price divided by two.

replacement effect requires us to factor in the levelized cost (LCOE) of wind generation. As a measure of short-run surplus, we define wind producer surplus as wind revenue, which only includes the price effect and the subsidies paid to wind producers, due to the importance of the assumptions surrounding LCOE on our final analysis. We analyze the impact of capital costs separately.

Subsidies are a net transfer from consumers to producers.[14] To compute the subsidy to wind producers, we collect annual data on subsidy transfers to wind generators, and we divide it by annual wind output. As explained in Section 2, there was a change in regulation during the period of study. Wind producers received a subsidy of approximately 45 EUR/MWh before 2013. After 2013, we find that the added cost per MWh drops to approximately 30 EUR/MWh, as shown in Figure 1. In the baseline results, we consider a baseline subsidy cost of 40 EUR/MWh, which constitutes a subsidy value in line with previous studies (Abrell et al., 2019).

Importantly, in addition to the changes in consumer and producer surplus, we take into account the environmental benefits of wind production. Because the energy price in the Spanish electricity market already reflects the costs of CO_2 to a certain extent via the EU-ETS mechanism (Fabra and Reguant, 2014), we only add the emissions benefits that are not directly included in the EU-ETS price. We regress net emissions costs ($(SCC - p_{CO2}) \times emissions$) on our wind splines to obtain the reductions in emissions costs due to increased wind production.[15] As with levelized cost, the overall results of our analysis on total welfare are sensitive to the chosen social cost of carbon. We highlight this sensitivity in our assessment of the policy benefits.[16]

4.1 Quantifying Welfare Effects

Figure 6 shows the results of our analysis for consumer surplus, non-wind producer surplus, and wind revenue at each wind quintile, with wind levels increasing from left to right within components. The impact of wind on consumer surplus (blue) is relatively small at low levels of wind, where the price effect is nearly equivalent to the cost of subsidies. However, at higher wind levels, a more dramatic decrease in electricity price is more than enough to offset the subsidies. The impact of wind on non-wind producer surplus (green) is consistently negative, due to the price effect overpowering the replacement effect. The impact of wind on wind revenues (purple) is positive but decreasing throughout the quintiles, given the cannibalization effect of wind production on wind revenues. Similar to consumer surplus, this is due to the sharp reduction in price at high levels of wind.

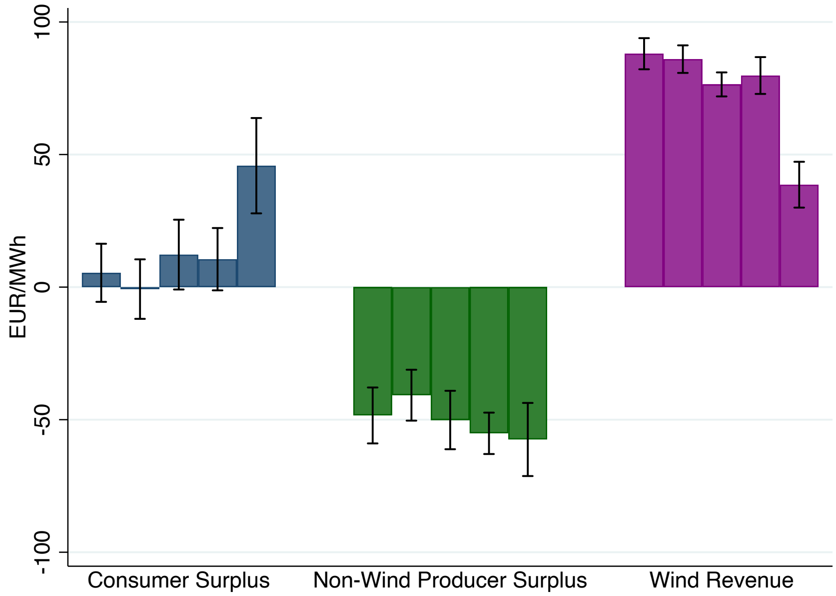
To analyze the overall welfare impacts, including emissions benefits and capital costs, Figure 7

[14] We abstract away from the cost of public funds for subsidies given that this are collected directly in the electricity sector. For reasonable values, they are not enough to change the sign of the welfare estimates.

[15] We obtain similar results if instead multiply the emissions marginal reductions by the average additional environmental benefit.

[16] Note that we are not considering other co-benefits of wind production, and therefore these environmental benefits could be considered lower bound on the environmental benefits of wind output.

Figure 6: Average Welfare Effects of Wind

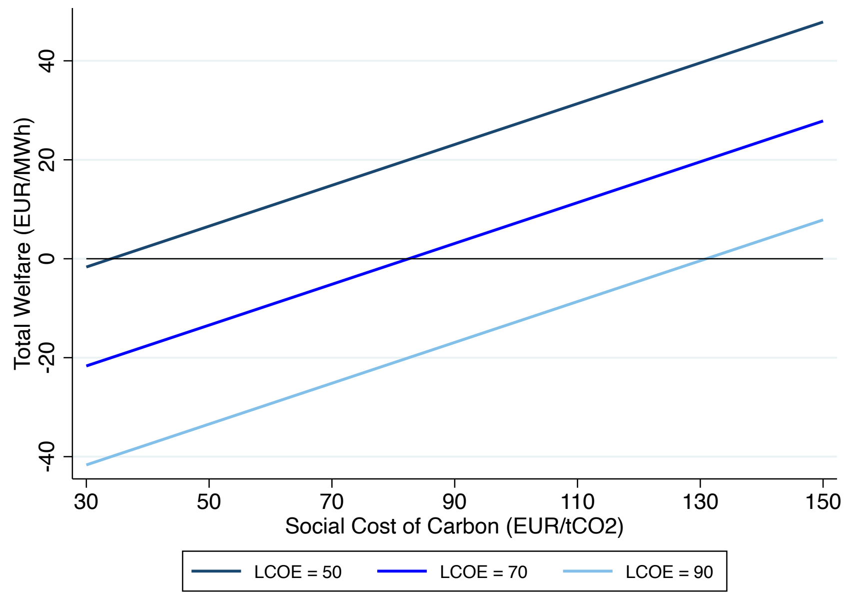


Notes: This figure shows the impacts of wind on various welfare components. Within each component, the effect is depicted at the five different wind quintiles, starting with the smallest quintile on the left, and moving to the largest quintile on the right.

shows the impact of two key variables, the levelized cost of wind and the social cost of carbon, on the results of our total welfare analysis. Depending on the choice of interest rate or the date of installation, wind farm levelized costs can easily range from 50 to 90 EUR/MWh. Additionally, the social cost of carbon is a highly debated metric, due to the uncertainty surrounding future damages and the choice of a long term discount rate. In Figure 7, we choose a high (90 EUR/MWh), medium (70 EUR/MWh), and low (50 EUR/MWh) set of levelized costs, and calculate the impact of wind on total welfare across a range of social costs of carbon. We find that at our lowest LCOE, the impact of wind on total welfare becomes positive at a very modest SCC of approximately 30 EUR/tCO_2. The medium and high LCOE specifications require larger social costs of carbon (80 EUR/tCO_2 and 130 EUR/tCO_2, respectively) to achieve a positive impact of wind on total welfare. However, all three of these "social cost of carbon cut-offs" are within the broad range of values climate scientists and economists recommend. Note that if we assume that wind farms at least recovered their capital costs under this policy, given that their estimated net revenues are around 55 EUR/MWh, welfare is positive as long as the value of emissions reductions is around 50-55 EUR/ton CO2, making the welfare benefits of the policy positive for costs of carbon in the lower range.[17]

[17] Under this assumption, this estimate can be considered an upper bound if the wind farms entered the market with positive surplus.

Figure 7: Welfare Sensitivity Analysis



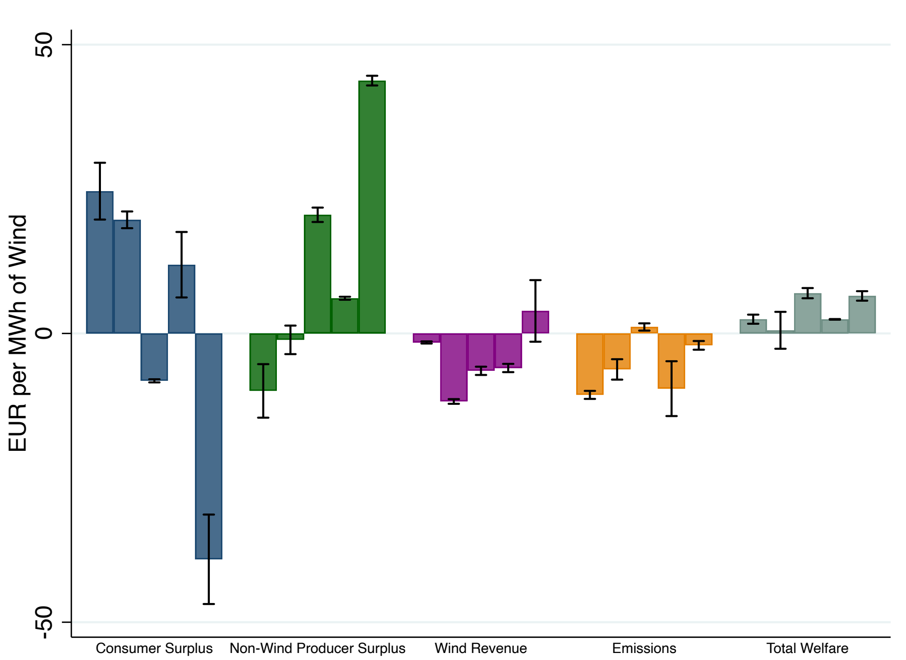
Notes: This figure illustrates the sensitivity of the overall welfare impacts of wind as a function of two key variables: levelized cost of wind, and social cost of carbon. The figure shows the "break-even" social costs of carbon (on the x-axis) of the policy intervention for different LCOE values (y-axis).

4.2 Welfare Effects from the Policy Change

The policy change implemented in June of 2014 altered the incentives of wind producers by switching their subsidies from output-based to capacity-based. To determine how this affects the Spanish electricity market, redo separately the analysis described in the previous two subsections for the observations prior to June 6, 2014, an the observations after June 6th, 2014. To make the before and after comparison of the event study more balanced, we consider only a year before and after the policy change. Based on Figure 1, we utilize a subsidy value of 45 EUR/MWh for the first half of the data, and a subsidy value of 30 EUR/MWh for the second half of the data. We use a mid-level value for the social cost of carbon of 100 EUR/tCO_2. The difference between these two results are shown in Figure 8.

Due to the different subsidy levels, at low levels of wind, consumer surplus increases, while wind revenues decrease. However, the most significant changes in Figure 8 occur in the fifth quintile of wind for producer and consumer surplus. Prior to the policy shift, we can see in Figure 6 that extreme levels of wind increased the price effect, thus benefiting consumers and harming producers. However, due to the change in wind producer incentives and subsequent almost complete removal of zero and near-zero prices, the policy change had a moderating effect on the market to the benefit of traditional producers. Although the curtailment of wind has a small, negative effect on emissions offsets, it also decreases system costs, which leads to the overall improvement of total welfare seen in

Figure 8: Average Change in Welfare Effects of Wind due to Policy Change



Notes: This figure shows the change in the impacts of wind on various welfare components due to the 2014 policy change, with emissions reductions valued at 100 EUR/ton CO2. Within each component, the effect is depicted at the five different wind quintiles, starting with the smallest quintile on the left, and moving to the largest quintile on the right.

the right-hand side of Figure 8. This highlights that going from output- to capacity-based subsidies has two main effects: (i) it is a transfer from consumers to traditional producers, as the subsidy no longer distorts bidding by wind farms, and (ii) the removal of bidding distortions has some positive benefits on the costs of intermittency, with modest benefits to total welfare overall.

5 Conclusion

We analyze the benefits and costs of wind production in the context of the Spanish Electricity Market. We take a comprehensive approach considering not only the market price and emissions effects but also the impacts of wind intermittency on system costs more broadly. We exploit the exogeneity of wind forecasts to show the marginal effect of wind on several relevant market outcomes. Our results demonstrate that wind and intermittency impose additional costs on the system.

However, the increases in such costs are modest in relationship to the general price decreases induced by wind power. We combine our evaluations of several market outcomes with information on government subsidies to conduct a thorough welfare effect of wind generation. We find that across most levels of wind, both producer and consumer surplus are positively impacted by the inclusion of wind power and its corresponding subsidies. Across all levels of wind, total welfare is positive, and made even more positive by factoring in the external benefits of reduced CO2 emissions.

Moreover, we apply this welfare analysis approach to evaluate the impact of a policy shift on the Spanish electricity market. We determine that a shift from output-based to capacity-based subsidies leads to curtailment of wind at upper-tail levels, thus minimizing instances of extreme price effects. This change has a moderating effect on welfare across wind levels, and leads to a decrease in system costs due to less complications throughout the grid. As a result, the June 2014 policy caused modest increases in total welfare within the Spanish electricity market.

Overall, our conclusion is that the negative impacts of wind on operational costs have been quite modest, even at relatively high levels of wind generation. There are different ways that the negative impacts of renewable intermittency are expected to decrease even further in the future. First, developing more accurate forecasts could reduce uncertainty. Second, power systems could contribute to a reduction in volatility by incorporating more storage technology. Another solution is for governments to encourage the use of real time pricing or time of use rates. If consumers are responsive enough, they will internalize generation costs and possibly transfer demand to hours when energy prices are lower or when renewable production is higher.[18] Finally, the use of smart

[18] While the Spanish market has emphasized some dynamic pricing regulatory changes for households, the evidence so far shows limited demand flexibility on the residential side (Fabra et al., 2021).

government policies can skew wind producer incentives, thereby minimizing extreme levels of wind and decreasing congestion throughout the grid.

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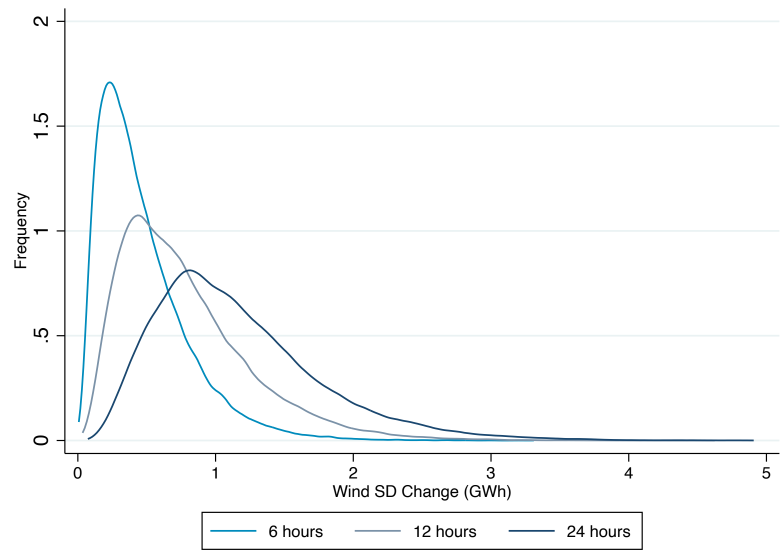
A Additional Tables and Figures

Table A.1: Regulation changes

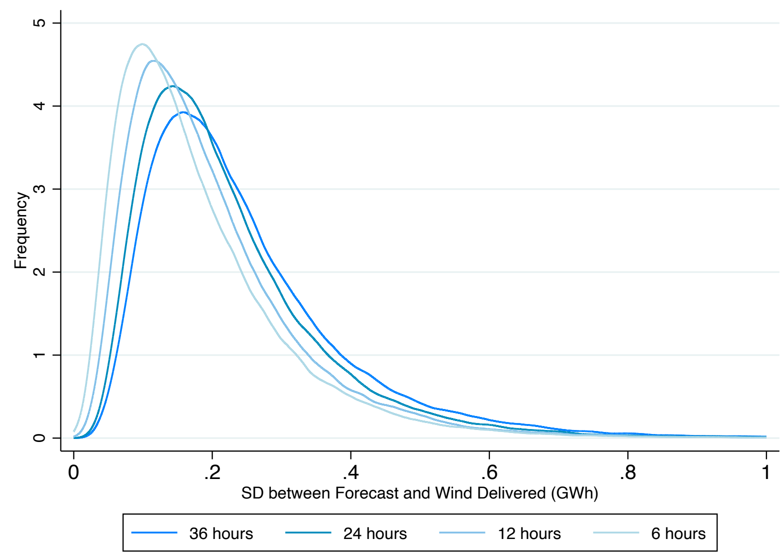
Regulation	Summary	Implications
Royal Decree-Law 1/2012 (January 2012)	Suppression of economic incentives (tariffs or premiums) for new electricity production facilities using renewable resources.	Limited installed wind capacity growth during our study period.
Royal Decree-Law 2/2013 (February 2013)	Elimination of the Feed-in-Premium (FiP) pricing scheme. Renewable producers up to this regulation could opt for two pricing schemes (a) Feed-in-Premium (FiP), or (b) Feed-in-Tariff (FiT). Under option (a), producers sold their electricity in the electricity market and their price would be determined by the market price plus a premium payment. Under option (b) or FiT, producers had to offer all their production at a zero price in exchange of a regulated compensation invariable for all scheduling periods.	Under this regulation, all producers under the FiP scheme are moved to the FiT scheme. The consequence of this regulation is that wind producers stops arbitraging intra-day markets (Ito and Reguant, 2016).
Royal Decree-Law 9/2013 (July 2013)	Renewable generators were no longer entitled to receive the two pricing schemes described in the above legislation (options (a) and (b)). This regulation in addition set up a new pricing scheme based on a reasonable compensation that was implemented in June 2014. During this period, the pricing scheme in place was the FiT scheme.	
Royal Decree-Law 413/2014, Orden IET/1045/2014 (June 2014)	Implementation of new pricing scheme for renewable producers already announced in the regulation of July 2013. The new compensation was based on installed capacity rather than produced electricity. It was calculated as the sum of a capacity payment to compensate investment costs not recovered through the market, and a production payment to provide investment incentives by reducing production costs. This regulation in addition stated the possibility of renewable sources' participation in adjustment markets (their participation effectively started in February 2016).	The new pricing scheme applied to facilities that had not recovered the investment costs previously (mostly capacity installed after 2005). Around 51% of the installed wind capacity was exposed to market prices as the lower subsidies would not compensate their operating costs. This exposure increased market prices, as renewable producers offer their production at least at their operating cost (no longer at zero prices). In addition, the participation of wind in adjustment markets in 2016 lowered prices in those markets.

[*] https://www.cnmc.es/sites/default/files/editor_contenidos/Energia/Consulta%20Publica/20190627_6_Informe%20Justificativo_POs_MIC%2015h-Tras%20Consulta%20P%C3%BAblica.pdf

Figure A.1: Distribution of Wind Intermittency



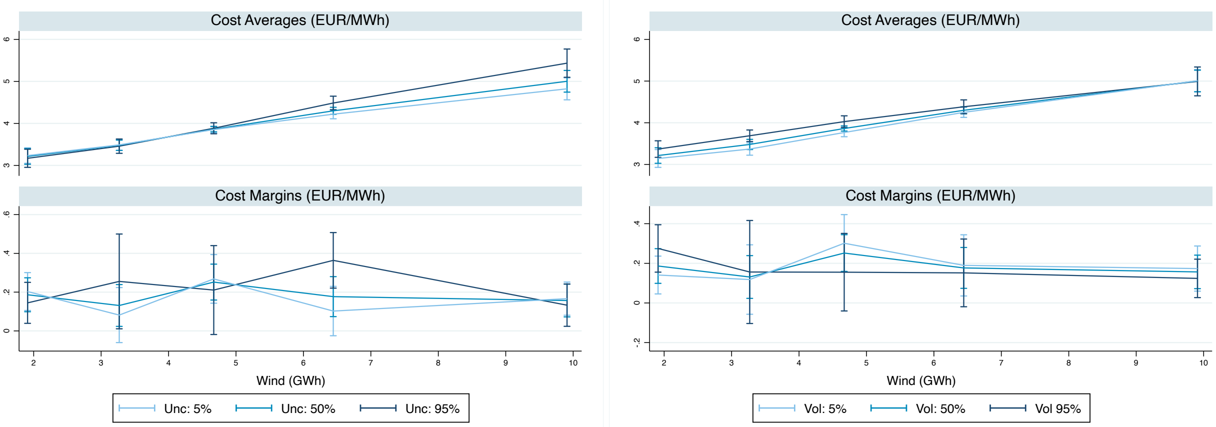
(a) Volatility



(b) Uncertainty

Notes: This figure shows two measures of intermittency: volatility and uncertainty. Volatility is defined as the standard deviation of changes in wind production during a certain length of time. We have computed volatility for 6, 12, and 24 hours output differences. Uncertainty is defined as the standard deviation of forecast departures from final wind delivered in the last H hours before production. We have computed uncertainty for 6, 12, 24, and 36 starting times. The distribution of uncertainty has been truncated at 1 GWh for improved readability.

Figure A.2: Impact of uncertainty and volatility on system costs



(a) Uncertainty Decomposition

(b) Volatility Decomposition

Notes: This figure compares the impact of wind on total system costs at different levels of uncertainty and volatility. The upper panel (Cost Averages) shows the average system costs impacts, whereas the lower panel (Cost Margins) shows the marginal effects. Volatility is analyzed at its 5th, 50th, and 95th percentiles, while uncertainty is maintained at its 50th percentile. For each wind quintile, we obtain the mean of wind forecast and use it on the x-axis. Uncertainty is analyzed at its 5th, 50th, and 95th percentiles, while volatility is maintained at its 50th percentile. For each wind quintile, we obtain the mean of wind forecast and use it on the x-axis.

Table A.2: Sensitivity to fixed effects of marginal impacts to operational costs

VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Forecasted wind (GWh)	0.238	0.215	0.232	0.179	0.234	0.194
	(0.0191)	(0.0193)	(0.0210)	(0.0184)	(0.0213)	(0.0168)
Forecasted demand (GWh)	-0.0651	-0.0459	-0.0616	-0.0386	-0.168	-0.159
	(0.0235)	(0.0225)	(0.0234)	(0.0225)	(0.0221)	(0.0197)
Solar production (GWh)	-0.263	-0.292	-0.381	-0.448	-0.449	-0.0166
	(0.0596)	(0.0545)	(0.0579)	(0.0557)	(0.164)	(0.0673)
Observations	78,730	78,730	78,730	78,730	78,730	78,706
R-squared	0.170	0.234	0.193	0.323	0.285	0.551
Year FE	No	Yes	No	Yes	No	Yes
Month FE	No	No	Yes	Yes	Yes	Yes
Hour FE	No	No	No	No	Yes	Yes

Notes: Standard errors clustered at the month of sample. All regressions include demand forecast, natural gas prices, temperature, temperature squared, dew point, and solar production as controls.

Table A.3: Daily marginal impacts to operational costs

VARIABLES	(1)	(2)	(3)	(4)
Forecasted wind (GWh)	6.274	6.260	6.408	6.290
	(0.473)	(0.472)	(0.472)	(0.488)
Forecasted demand (GWh)	0.122	0.0914	-0.0326	-0.0173
	(0.564)	(0.558)	(0.553)	(0.559)
Solar production (GWh)	8.400	9.128	9.123	7.018
	(5.393)	(5.186)	(5.396)	(6.616)
NG price (EUR/MWh)		61.71	56.26	55.49
		(45.05)	(44.10)	(43.86)
Mean temperature (F)			-56.01	-46.11
			(40.11)	(43.19)
Sq. mean temp. (F/1000)			322.5	271.1
			(307.8)	(317.6)
Mean dew point (F)				-4.010
				(7.744)
Observations	3,293	3,293	3,293	3,293
R-squared	0.664	0.665	0.668	0.668
Implied average effect	0.219	0.218	0.223	0.219

Notes: Standard errors clustered at the month of sample. All regressions include month of sample fixed effects. The dependant variable is the daily sum of operational costs in thousands of dollars.

Table A.4: Impact of wind vs. forecasted wind

VARIABLES	(1) Wind Forecast	(2) Wind	(3) Wind IV
Forecasted wind (GWh)	0.194		
	(0.0168)		
Final wind production (GWh)		0.154	0.185
		(0.0144)	(0.0155)
Observations	78,706	78,707	78,706
R-squared	0.551	0.547	0.080

Notes: Standard errors clustered at the month of sample. All regressions include demand forecast, natural gas prices, temperature, temperature squared, dew point, and solar production as controls.