Market Integration and Wind Generation: An Empirical Analysis of the Impact of Wind Generation on Cross-border Power Prices

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ABSTRACT:

European power markets have become more integrated and renewables have a significant effect on power prices and cross-border exchanges. This paper investigates empirically how the effects of renewables are affected by market expansion across two adjacent countries (France and Germany), based on market data and proprietary data on book orders. We find that wind production lowers power prices on average and increases volatility, not only domestically but also across borders. Using multiple counterfactuals, we examine how our results depend on the level of interconnection and find that further interconnection capacity would decrease price volatility in both countries since the benefits of a larger market would outweigh the contagion effects of volatility. Our findings have important policy implications as they demonstrate the need to coordinate support policies for renewables and policies to support transmission capacity expansion in order to mitigate the impact of volatility on power prices in neighboring power markets.

Keywords: electricity market, renewables, market coupling, MGARCH

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1. INTRODUCTION

European electricity markets have become increasingly integrated in the past decade as a result of improvements to market design such as the implementation of day-ahead market coupling through implicit auctioning of transmission rights.[1] This flagship project started with three countries in 2009 (France, Belgium, and the Netherlands), and was extended to Germany in 2011. By the end of 2015 about 85% of the electricity consumption in the EU was coupled in a single market. By implicitly allocating interconnection capacity, market coupling can achieve a more efficient use of cross-border interconnection capacity, and has substantially increased price convergence across European countries. The European Commission continues to push for further integration, through building up cross-border power lines, and removing barriers to cross-border trade.

As a consequence, national policies that affect the power generation mix can be expected to have a growing effect across borders on neighboring countries. Yet national policies in support of certain technologies remain poorly coordinated. European countries have set ambitious deployment

1. Cross-border trade of electricity has grown to represent about 232 TWh/year, or about 7% of total electricity production.

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targets for renewables for 2020 and 2030 (20% and 27% of final energy consumption, respectively), but the support mechanisms remain national. As a result, whilst overall renewable energy generation in Europe grew from 20% in 2000 to 31% in 2015, growth has been much faster in some countries than others, with countries such as Germany leading the charge. The rapid growth of renewable energy generation has had significant effects on power prices in a number of European countries such as Germany. Electricity prices have become more correlated with the intermittent nature of wind energy production and more volatile.

The joint process of deploying renewables and integrating power markets raises a number of questions. There is significant literature demonstrating that renewables affect the power price level and volatility within a country. However, for neighboring countries with coupled markets there is, to our knowledge, no research that investigates to what extent the deployment of renewables on one side of the border affect power price dynamics on the other side. Moreover, the effect of renewables depends on the amount of physical cross-border capacity available. To what extent does an increase in interconnection capacity influence the effect of renewables on cross-border prices, and what are the implications for the value of new interconnections?

These issues are timely research questions in Europe in particular as the European Council of October 2014 called for all Member States to achieve interconnection of at least 10% of their installed electricity production capacity by 2020 and the EU is looking into raising the target to 15% by 2030. The EU is putting in place financial incentives and instruments to support investment of about €40bn by 2020 in order to reach the target (EC, 2015). This has raised questions as to whether such an interconnection target and greater market integration would be consistent whilst policies to drive the development of renewables continue to be national and lack coordination (Mezosi et al. 2016; Newbery et al., 2016).

This paper investigates these issues by considering the case of France and Germany, which are interconnected with about 1.8 GW of export capacity and 2.5 GW of import capacity from France to Germany in 2015[2] (compared to an average daily peak demand of 60 GW in France and 63 GW in Germany in 2015). Installed wind capacity has grown substantially in Germany from 25 GW in 2010 to more than 45 GW at the end of 2015. France has seen a slower development of wind power with 4 GW installed in 2010 and 10 GW at the end of 2015. Moreover, France and Germany were among the five pioneering countries where market coupling was launched in 2011. Based on daily electricity prices of the period 2012–2015, we investigate the effect of wind power in both countries on power prices both domestically and across the border. We estimate both the effects on price levels and volatility. Finally, we use detailed order book data from the spot market operator to analyze counterfactuals for different interconnection capacities between France and Germany.

We find that intermittent wind generation has a significant impact on electricity prices in both the domestic and the neighboring market. Wind production lowers electricity prices and increases their volatility. In addition, we find that increasing the interconnection capacity between France and Germany would cause a transfer of the wind-related volatility to the neighboring country's electricity prices. However, the analysis of the overall effect of expanding interconnection shows that the transfer of wind-related price volatility is mitigated and even offset by the dampening effect of integrating the markets (resulting from larger demand and supply).

The remainder of this paper is structured as follows. Section 2 presents the literature review, section 3 describes the data and introduces the research questions. Section 4 discusses the specifications of the econometric analysis. Finally, the results are presented and analyzed in section 5, and section 6 concludes by discussing the policy implications of our results.

2. Average available transfer capacities over the sample data.

2. LITERATURE REVIEW

There is well-established evidence that wind power generation has, in the short term, a depressive effect on average power prices, and that it increases the volatility of power prices. This is often referred to as the 'merit order' effect of renewables such as wind turbines. These low-variable-cost technologies displace more expensive technologies in the merit order, leading to a reduction in average prices; however, because their production is variable, they increase the level of volatility of power prices. Several authors characterized the depressive effect of intermittent wind generation on electricity prices (see for instance Jensen and Skytte, 2002; Sensfuss et al., 2008; and Nicolosi and Fürsh, 2009). Würzburg et al. (2013) provided a survey of simulated and empirical studies which assess the relationship between renewable generation and electricity prices. Concerning the German market, Bode and Groscurth (2006), and Traber and Kemfert (2009 and 2011) found that renewable generation lowered the average electricity price based on simulation studies. This effect has also been confirmed in Denmark (Holttinen et al., 2001; Munksgaard and Morthorst, 2008) and in Spain (Saenz de Miera et al., 2008; Linares et al., 2008). Our paper takes the analysis one step further by explicitly considering the simultaneous relationship between wind production in both France and Germany and prices in these two integrated markets.

While the previous papers used average daily data for wind production and power prices, a few papers used more granular data capturing the impact of hourly variations. For example, Neubarth et al. (2006) applied a simple linear regression to estimate the effect of wind generation on spot prices in Germany. Similar studies were conducted with Spanish, Irish and Dutch data (Gil et al., 2012; O'Mahoney and Denny, 2011; Nieuwenhout and Brand, 2011). Jonsson et al. (2010) analyzed hourly Danish data for wind and prices, using a non-parametric regression model.

Our paper contributes to the literature in two distinct ways. First, there are, to the best of our knowledge, no papers simultaneously investigating the impact of wind generation on cross-border power prices in the case of coupled markets. Keppler et al. (2016) investigated the effect of market design as well as renewable generation on the price spread between France and Germany. They found that on average renewables were increasing the price spread while allocating interconnection capacities through implicit auctions (market coupling) improved the price convergence (for more information about the inefficiency of the previous regime of explicit auctions see Creti et al., 2010 or McInerney and Bunn, 2013). Besides this paper, most of the empirical papers only deal with the domestic impact of intermittent renewable energy production on power prices. Keppler et al. (2016) mainly focused on the impact of German renewables on the price spread whereas our paper aims to estimate the simultaneous effect of wind production on domestic and neighboring electricity prices (both in term of level and volatility). Ketterer (2014) estimated the impact of wind production on price volatility but restricted the analysis to a single country.

Second, we use historical market resilience data (i.e. price variations resulting from supply and demand changes) from the spot market operator to assess the impact of increasing the physical interconnection capacity on electricity price dynamics in both France and Germany and on the way in which wind power production in both countries affects these price dynamics. This is, to our knowledge, the first empirical study to investigate this effect, and our paper, therefore, complements the existing literature which employs simulation models to study the impact of grid expansion on power price dynamics and volatility. For instance, Schaber et al. (2012) modelled the effect of grid extensions for European power markets, with an increasing share of wind capacity until 2020; Denny et al. (2010) focus on Ireland and Great Britain. They both found that grid extension would lead to more homogeneous and stable electricity prices. Similarly, Spiecker et al. (2013) developed a model covering 30 European countries which simultaneously determines generation dispatch and investments as well as transmission use. Their model indicates that wind integration requires the development of additional interconnection capacities (see also Lynch et al., 2012). The intuition behind these results is that more interconnections increase the geographical spread of wind generation, and because wind-streams are generally less correlated over large distances this tends to smooth out the variability of wind production over the full portfolio (see Roques et al. (2010) for a discussion about optimal geographic diversification of wind sites). This, in turn, lowers the variability of power prices in the aggregated area, an effect which can be particularly important for isolated areas (see Soder et al., 2007). Note that, although the power price volatility may decrease at a local level, one can still expect shock transmission and volatility transfer between interconnected markets (see Worthington et al., 2005; Bunn and Gianfreda, 2010).

A related stream of literature investigates the value of increasing the size of interconnections. Mezősi et al. (2016) provided a review of the recent literature and concluded that the European policy target of 10% interconnection by 2020 may not be optimal neither with regard to security of supply, nor market integration. Newbery et al. (2016) survey the barriers to further market integration and identify potential significant welfare gains from further interconnection that would remove unscheduled flows. Our approach differs from the existing literature since we use empirical methods rather than simulated models to analyze the relative impact of interconnection size on market integration. First, we use detailed supply and demand book orders from the market operator to calculate what the prices would have actually been for different levels of interconnection expansion. Then in a second step we apply multivariate generalized autoregressive conditional heteroscedasticity (GARCH) models to analyze how sensitive the impact of renewables is to a change in the interconnection capacity between the two countries.

3. RESEARCH QUESTIONS AND DATA DESCRIPTION

3.1 The impact of renewables on cross-border power price dynamics

Our first objective is to confirm the results of previous studies (e.g. Ketterer, 2014) which found that wind generation has a negative impact on the average domestic spot price and a positive effect on domestic price variance using a larger dataset for Germany as well as wind production estimates for France. Given that Germany has continued to increase its intermittent renewable capacity since the previous studies and that interconnection capacity has remained stable, we could expect our results to confirm the results from these previous studies.

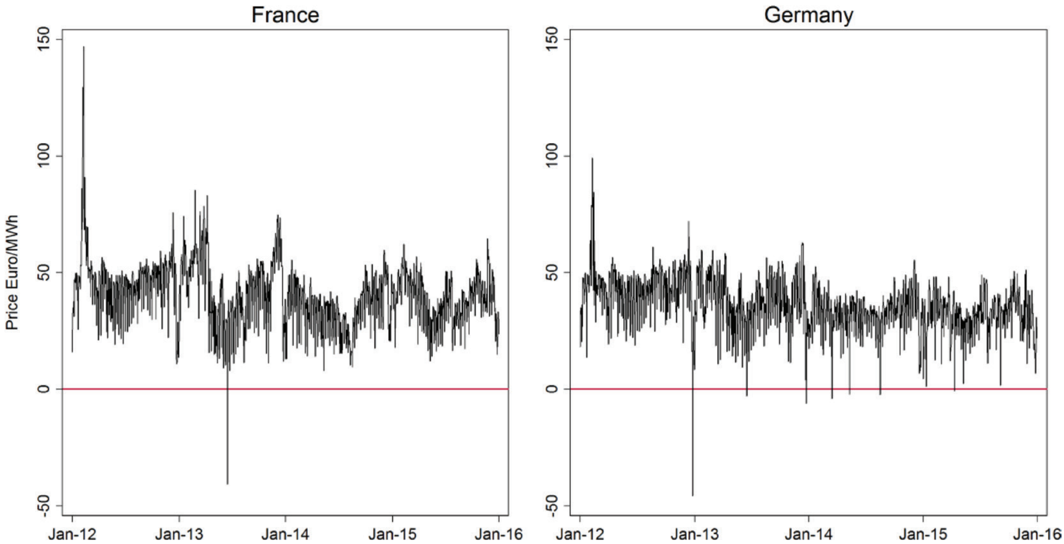
In addition to extending previous studies with French data, we are interested in the impact of wind generation on the neighboring market across the border. Our intuition is that the interconnection between France and Germany is large enough to spread the depressive effect of wind generation to prices in the foreign market, especially since our study covers a period during which the French and German day-ahead markets were coupled. Similarly, we expect wind production in one country to marginally increase electricity volatility in the neighboring market.

Our first research hypothesis can therefore be expressed as follows:

> *Hypothesis 1: Intermittent wind generation simultaneously impacts domestic and foreign electricity prices when markets are integrated.*

Since previous studies only focused on a single country (Benhmad and Percebois, 2013; Ketterer, 2014; Clò et al., 2015) the econometric analysis was conducted with a generalized autoregressive conditional heteroscedasticity (GARCH) model, which is particularly relevant for this kind

Figure 1: Aggregated daily prices in France and Germany between 2012 and 2015



of study because it estimates both the mean and the variance of the dependent variable. Knowing that France and Germany are integrated markets, we use a multivariate GARCH model to simultaneously estimate the impact of renewables in the two countries.

Our database covers the period between January 1st 2012 and December 31st 2015. Figure 1 shows the daily average electricity prices in the French and German markets. Negative price episodes in Germany can be explained by a surplus of renewables production combined with a low demand which led some generators to prefer to bid at negative prices rather than having to curtail production. German renewable generation and day-ahead prices for France and Germany come from the EPEX SPOT and EEX market operator databases.[3] At the end of 2015, Germany (resp. France) had more than 45 GW (resp. 10 GW) of wind capacity.

In addition, since power consumption is one of the most important factors of electricity prices, we used French and German daily average demand as explanatory variables in our model. Consumption data are from the ENTSO-E database[4].

Table 1 reports summary statistics for our main variables. On average, daily prices are lower and proportionally less volatile in Germany than in France. Consumption in both countries is comparable in level but the residual demand is much larger in France due to the higher wind production in Germany. We also reported the average Available Transfer Capacity (ATC) which is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses by transmission system operators. The ATC will be used as a proxy for interconnection variation in our robustness tests section.

3.2 The impact of increasing interconnection capacity

Secondly, we assess the effect of increasing interconnection capacity on French and German price level and volatility. We also estimate the effect of this increased interconnection capacity on wind-electricity price relationship. International trade theory and general microeconomic princi-

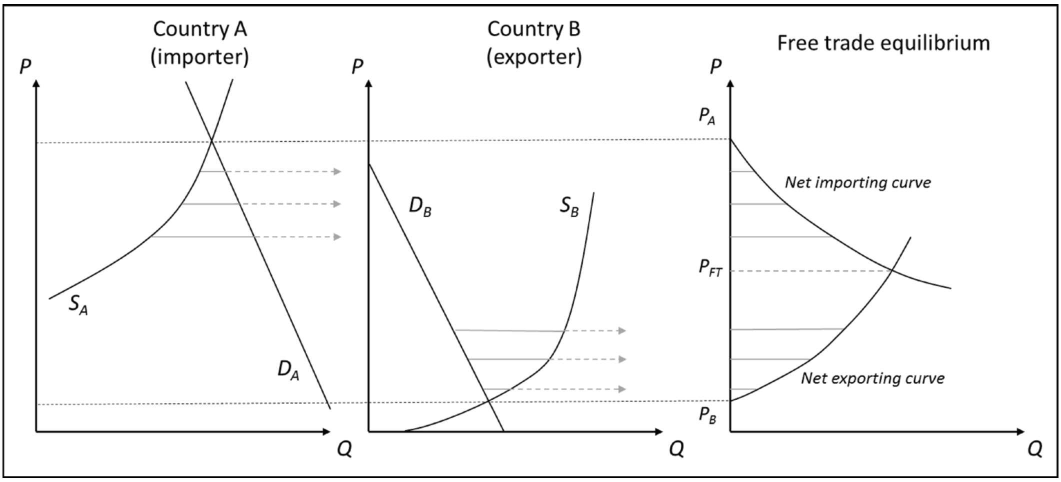
3. EPEX SPOT is a large continental power exchange
4. ENTSO-E is the association representing the 41 European electricity Transmission System Operators

Table 1: Daily average summary statistics

Variables	Unit	Mean	Std. Dev.	Min	Max
France					
Price	€/MWh	40.63	13.56	–40.62[a]	147.13
Wind	GWh	1.91	1.25	0.15	6.94
Consumption	GWh	54.48	11.09	35.69	94.09
Germany					
Price	€/MWh	36.25	11.18	–45.69[b]	99.29
Wind	GWh	6.32	5.35	0.27	29.02
Consumption	GWh	54.67	6.67	37.52	69.12
ATC	MW	1768	211	745	2245

a, b Negative prices can occur due to renewables dispatch priority and lack of system flexibility. Negatives prices occurred 7 times in Germany and once in France over our 4 years daily data sample.

Figure 2: Free trade equilibrium with a homogeneous good



ples are useful references for analyzing cross-border electricity exchanges, specifically since electricity is a perfectly homogeneous product. Take two countries A and B where producers only have the same homogeneous good to trade. If they are competing in a free trade universe (without any tariffs, quotas, or transport costs) the equilibrium price—defined by the net exporting and importing curves—will stand between the autarky prices P_A and P_B (see Figure 2). Any variation in one of the countries will mechanically impact the price in the other country.

While this is a useful simple theoretical benchmark, electricity markets have a number of singularities which need to be taken into account. In particular, electricity transport faces physical constraints such as cross-border capacity availability. Congestion arises when optimal exchanges are greater than the available transmission capacity (ATC) which is determined by the transmission system operators (TSO) after deducting security margins and long-term contracts from the total physical capacity.[5] Note that, over the period considered in our study, the French and German mar-

5. The procedures for the calculation of Total, Net and Available Transfer Capacities (TTC, NTC, ATC) are coordinated at the European level. Each Transmission System Operator (TSO) determines a Net Transfer Capacity (NTC) value for each direction on each border of its control area based on historical data for a reference day, taking into account potential loop flows, seasonal impact and a justified security margin. From the NTC figures, the Available Transfer Capacity (ATC) value

kets were coupled via implicit auctioning of cross-border transport rights, and cross-border capacity is therefore allocated automatically by the TSO to avoid flows in the opposite direction to the price differentials. This means that regardless of the end user location, suppliers do not have to bid explicitly for interconnection capacity. Instead they send a set of price and quantity offers to the market operator which then implicitly allocates cross-border capacity.

As a consequence, one could except that volatility caused by intermittent wind generation in Germany is likely to affect the French market, and vice versa. However, in reality cross-border exchanges are sometimes limited and constrained by the interconnection capacity. If the interconnection capacity is congested, prices diverge and an instantaneous shock in one country will not get transmitted to the neighboring markets. Therefore, increased physical transmission capacity can affect cross-border spill-overs of power price levels and volatility. One of the objectives of this paper is to assess the effects of increasing the interconnection capacity on French and German electricity prices, as well as on their reaction to intermittent wind production.

Hypothesis 2: Increasing interconnection capacity intensifies the impact of intermittent wind generation on the neighboring market and lowers the effects domestically.

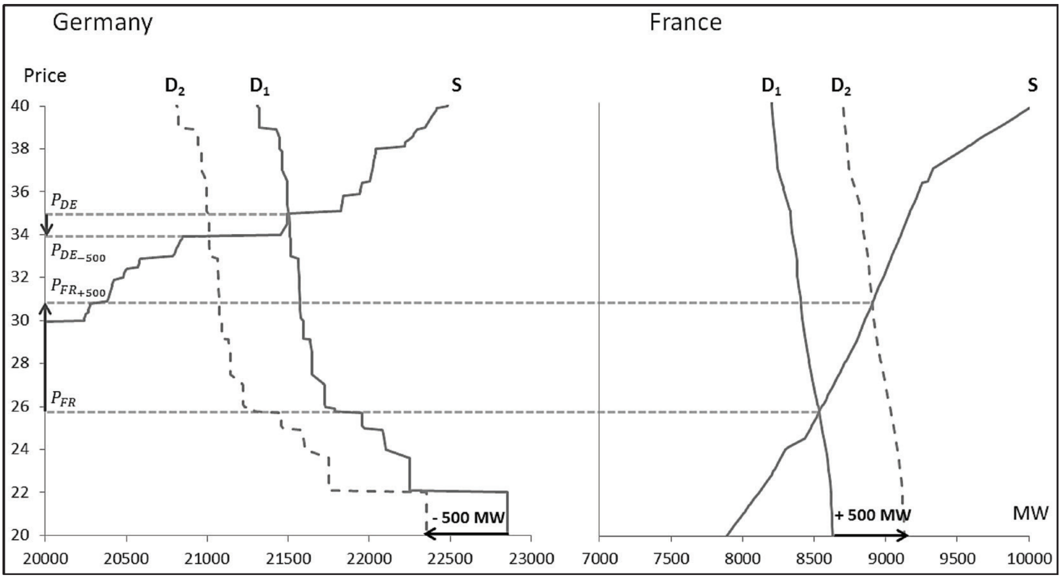
Our intuition is that by increasing physical interconnection capacity, the German market would "transfer" part of the volatility generated by its wind generation to the French market, and vice versa. In order to evaluate this effect empirically, we use market resilience data (i.e. price variations resulting from supply and demand changes) from the market operator EPEX SPOT.

Market resilience data can be seen as the demand (or supply) shift resulting from a price variation. According to EPEX spot definition, resilience data return price variations resulting from demand and/or supply shifts. The effect of an interconnection expansion on electricity prices can therefore be analyzed by simultaneously looking at the effects of a positive variation of the demand in the exporting country (the country with the lowest price) and a negative variation of the demand in the importing country. We use these resilience data to recreate what the price would have been in both Germany and France if the interconnection had been expanded by x MW from January 2012 to the end of 2015. To be more specific, we compute resilience data by aggregating the overall hourly demand and supply orders for each market. Then, we use these hourly supply and demand curves for France and Germany and simultaneously shift the demand in opposite directions depending on whether the country is an exporter or importer. This approach allows us to reconstruct electricity prices in France and Germany for 25MW stepwise expansions of the interconnection capacity up to 2000MW. Finally, we aggregate these hourly prices on a daily basis in order to be consistent with the granularity of our baseline model.

The congestion rent is collected equally by the two TSOs and is equal to the price difference multiplied by the interconnection capacity. Therefore, reducing the price spread by increasing the interconnection capacity would lower the TSOs' rent but not necessarily their utility depending on their objective function. Figure 3 illustrates a concrete example for May 5th, 2013 at 10pm. At this specific hour, the German price was higher than the French price (which necessarily means that interconnection was congested). We reconstructed prices for an expansion of 500MW by simultaneously comparing the French counterfactual price for a demand 500MW higher with the German price if the demand was 500MW lower. Note that in this example, increasing the interconnection capacity by 500MW would not have been enough to reach a full price convergence but a 1000MW

was before Flow Based Market Coupling implementation simply derived by subtracting long-term nominations from the NTC. For a more detailed explanation of the impact of Flow based market coupling on ATC computations, please see KU Leuven (2015).

Figure 3: Market resilience for a 500MW demand variation in France and Germany on May 5th 2013 at 10pm



Data: EPEX spot

expansion would have been sufficient (and possibly oversized). The effect of increasing the interconnection capacity is different in the two countries: in our example it has a small impact in Germany but French prices are affected to a higher extent (plus 4 euros). This would have generated a surplus gain both for German consumers and French producers, and would have lowered the TSOs' congestion rent[6]. On the opposite German producers and French consumers would suffer welfare losses.

The market operator resilience data were therefore useful in assessing the effect of a higher interconnection capacity on the mean and the variance of electricity prices, but these data also allowed us to conduct a comparison of the marginal impact of wind generation for different levels of interconnection capacity expansion. In other words, we could assess what would have been the effect of wind generation on prices in both countries if there had been a larger interconnection over the 2012–2015 period.

One limit of applying this method is that we only consider two regions and implicitly assume that a demand shift in one country will be absorbed entirely by the other country, whilst in reality France and Germany are also interconnected with other countries. However, for all the hours when France and Germany are coupled (roughly 50% of the time) our counterfactual series are equal to the baseline. For the remaining hours we need to distinguish several cases.

Case 1. Both countries are isolated as interconnection to third countries are congested

Whenever France and Germany's all other interconnectors are congested, our counterfactuals are accurately calculated since other countries would not have been able to contribute to the demand nor the supply.

6. The congestion rent is collected equally by the two TSOs and is equal to the price difference multiplied by the interconnection capacity. TSOs have various objective functions, in France, RTE has a public charter to guarantee equitable access to its electricity market.

Case 2. The importing country has underused interconnections

If the importing country is still connected to a third country when the France-Germany interconnector is congested, these regions have the same price and our methodology provides a lower bound estimation of the counterfactual price. Indeed, either the marginal power plant is in France or Germany and we correctly model an interconnection increase (demand is totally absorbed by the importer); or this marginal unit is in the third country which means that the exact counterfactual price is lower than our estimation. Even if 100% of the demand is absorbed by the third country, it does not mean that price in the importing country remains the same: it will decrease just as much as in the third country since they are coupled without grid congestion. If the interconnector toward this third country is not large enough to absorb the entire demand, it will get congested and we are back to the *case 1.* Please note that a lower bound on the price in importing country means an upper bound on price convergence.

Case 3. The exporting country has underused interconnections

The intuition in this case is similar to *case 2*. Our methodology assumes that the totality of the exported electricity comes from a single country. If the marginal unit is in the exporting country, our counterfactuals are correct. However, if a third country could have provided some cheaper electricity, we are estimating a higher exporting price than the counterfactual. In such case, our estimated prices for France and Germany would converge faster that in reality. However, we believe that the bias coming from this approximation is relatively small for two reasons. First, our analysis focusses on the impact of wind generation and we could argue that if the proportion of wind production in France or Germany is particularly high on a given hour, it will most likely mean that this country is the marginal producer. Second, in both *case 2* and *case 3*, one could argue that even if the marginal unit is located in a third country, the fact that the interconnector to this third country is not congested means that only a few hundreds of megawatts are enough to ensure price convergence. In such hours, the merit order of the exporting country and the merit order of the third country are likely similar at the margin and we can then expect our counterfactuals to be therefore reasonably close to the actual counterfactuals.

In addition, our methodology implicitly assumes constant biding behavior. It is unlikely that an interconnection expansion would affects the biding behavior since the market clearing is defined via merit-order. Moreover, since France and Germany are under a "price-market coupling", interconnection capacities are automatically allocated by the market operator. One could argue that a limited interconnection capacity facilitates the use of market power, and that by increasing the interconnection size such market power would be mitigated. First, it is very difficult to track the use of market power as we do not have data at the individual level on the firm costs. Second, the use of market power in electricity markets is usually manifested by an artificial price increase in period of low supply. In this study we principally focus on the impact of wind production, which by definition are mostly periods of high supply.

4. ECONOMETRIC MODEL

Modelling electricity prices involves several econometric issues. The non-storable nature of electricity leads to relatively high price volatility. Since the residual demand varies during the day, supply has to adjust in real time to balance the electricity system. Therefore, power prices are higher during peak consumption periods. We chose to ignore demand variability across the day by aggregating data at the daily level (simple mean) because hourly prices on day-ahead markets are set simultaneously.

Daily average of electricity consumption and wind production are used as explanatory variables since both the power generation merit order and power demand are key factors of electricity prices. During the winter, demand and power prices are particularly high, especially in France due to the high consumption sensitivity to cold temperatures. Huisman (2008) demonstrates the impact of the weather on price variation and shows that the marginal effect of temperature variations on power prices changes between seasons. Consumption data do not account for power plants' auto consumption. Finally, since market coupling ensures a more efficient utilization of interconnection capacity (see for instance Newbery and McDaniel (2002), Creti et al. (2010) and Keppler et al. (2014)) we also include the available transmission capacity (ATC) in a sensitivity test.

Considering the volatility of electricity prices, conditional heteroscedasticity models appear to be the most appropriate solution. GARCH models are commonly used to analyze variations in commodity markets because they are well fitted to capture the fluctuation and clustering of volatility. Knittel and Roberts (2005) were among the first to use the GARCH model on electricity prices. Several other authors also used the GARCH model to analyze electricity prices, especially for price volatility. A simple way to estimate electricity price level and conditional variance for a single country would be to use an AR-GARCH model:

$$y_t = \mu + \sum_{p=1}^{P} \phi_i y_{t-p} + \epsilon_t, \;\; with \;\; \epsilon_t \,|I_{t-1} \sim N\left(0, h_t\right) \tag{1}$$

$$h_t = \omega + \sum_{q=1}^{Q} \alpha_q \epsilon_{t-q}^2 + \sum_{m=1}^{M} \beta_q h_{t-m} \tag{2}$$

Where y_t is the average daily electricity price[7] at time t and h_t is its conditional variance. μ is the constant term, ϵ_t is the error term and ω is the long-term variance. I_{t-1} represents the market information in the previous period. If we want our model to be stationary we have to respect the following two conditions:

$$\Sigma \alpha_q + \Sigma \beta_m < 1 \tag{3}$$

$$\alpha_q, \beta_m > 0 \tag{4}$$

One particular aspect of our study is that French and German markets are integrated. One could argue that volatility spill-over is to be expected between electricity prices in France and in Germany. This effect can be estimated with a Multivariate-GARCH model. Only Worthington et al. (2005) and Higgs (2009) have looked at volatility spill-over in electricity spot markets using an MGARCH model. These authors were only focusing on infra-national markets but in theory, the mechanisms driving inter-regional spill-overs are similar to those between integrated national markets. Since this study is the first to look at the spill-over between national integrated markets, we decided to follow the infra-national literature and we estimated a Multivariate GARCH model based on the similarities of our analysis.

In addition, we aggregate data at the daily level in order to keep the lags and the time structure of the model consistent with day-ahead markets nature. Spot prices in the French and German markets are determined one day ahead, which means that the prices are simultaneously fixed. Therefore, the spot price for one hour does not carry any more information than the price at h+1 within the

7. Electricity prices are stationary both in France and Germany, the Dickey Fuller statistics are –38.34 and –30.08, respectively (the 1% critical value is –3.43)

same day. Some recent papers dealing with German spot data have successfully used this approach (Benhmad and Percebois, 2016 and Ketterer, 2014, Würzburg et al, 2013, Sensfuss et al., 2008).

We use consumption and wind generation as our main independents variable, and log transform them as well as the left-hand side variable to better interpret the results. Intuitively, we expect the impact of domestic wind production to have the same effect in neighboring markets but with a lower magnitude since interconnection capacity is limited. When interconnections are congested the shocks coming from wind production have to be absorbed by the domestic market.

One of the main objectives of this study is to analyze the relationship between intermittent wind power generation and price volatility when interconnection capacity increases. To investigate this issue we apply the same MGARCH specification to the new prices accounting for interconnection capacity modifications based on resilience data. Since we want to use the same equation specification for the 21 different series of prices[8] it is necessary to keep a simple equation for the conditional variance and limit the number of parameters to be estimated. Therefore, for each market the conditional variance is only composed of the ARCH term (α), the GARCH term (β), the wind generation and the consumption in the country concerned. For the same reasons we do not add cross spill-over in the conditional variance equation and we assume that the conditional correlation is constant over the period.

With these modifications, the specification for the mean equation of the M-GARCH(X) model becomes:

$$Y_t = \mu + \sum_{p=1} \Phi_p Y_{t-p} + \sum_{k=1} \Upsilon_k X_{kt} + E_t \tag{5}$$

Where Y_t is a $2x1$ vector of daily prices at time t for each market, μ and E are $2x1$ vectors capturing the constant terms and the errors terms with $\epsilon_{i,t} \mid I_{i,t-1} \sim N(0, H_t)$, the elements a_{ijp} of the $2x2$ matrices $\Phi_1 \ldots \Phi_p$ are the degree of spill-over effect across and within market at period *t-p* in the mean equation. Both BIC and AIC suggest 8 number of auto-regressive and mean spill-over for the mean equation, which is roughly consistent with a weekly cycle. Each Υ_k is an $1x2$ vector of coefficients associated to one of the market specific covariates X_k, including domestic wind power generation, foreign wind generation, national consumption, and seasonal dummy variables[9].

Restricting the conditional correlation to be constant allows us to substantially reduce the number of parameters to be estimated. Let H_t be the conditional covariance matrix:

$$H_t = D_t R D_t = \begin{pmatrix} h_{11} & h_{12} \\ h_{21} & h_{22} \end{pmatrix} \tag{6}$$

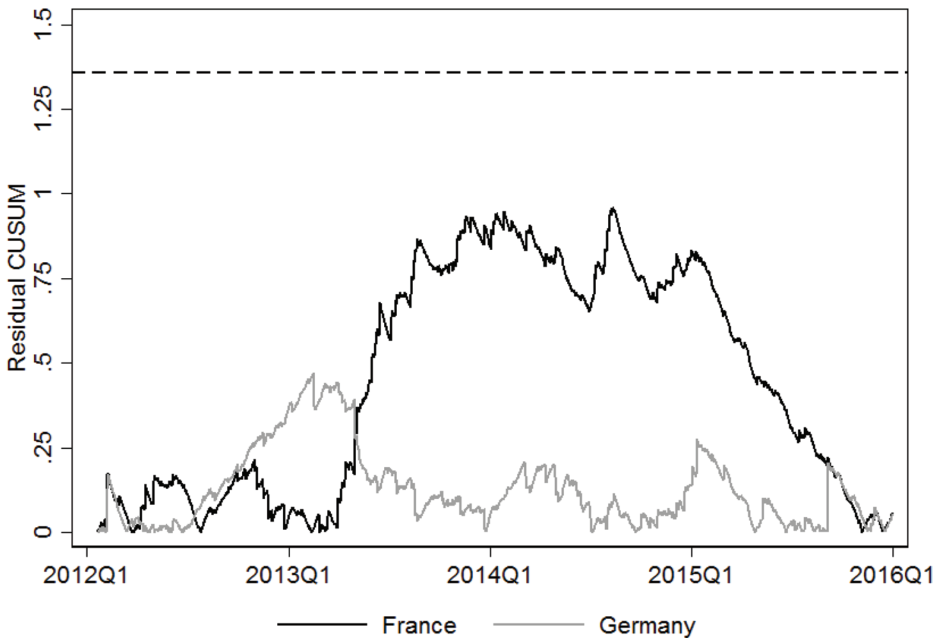
Where, $D_t = diag\left(h_{11t}^{\frac{1}{2}}, \ldots, h_{22t}^{\frac{1}{2}} \right)$ and $R = (\rho_{ij})$ is positive definite with $\rho_{ii} = 1$. Off-diagonal elements of H_t are computed as $h_{ijt} = \rho_{ij} \sqrt{h_{ii,t} h_{jj,t}}$ and diagonal elements of the conditional covariance matrix are modelled similarly to univariate GARCH:

$$h_{iit} = \omega_i + \sum_{q=1}^{Q} \alpha_i \epsilon_{i,t-q}^2 + \sum_{m=1}^{M} \beta_i h_{ii,t-m} + \sum_{k=1}^{K} \gamma_{ik} X_{ik,t}, \quad i = 1,2 \tag{7}$$

Where ω_i is capturing the constant term, α and β account for the sensibility and the persistence of past shocks. Finally, we are using the same set X_k of covariates that we used in the mean equation

8. Baseline prices, prices with an interconnection expansion from 100MW to 2000MW.
9. Electricity price and all right-hand side variables except seasonal dummies are log transformed.

Figure 4: Residual CUSUM statistic over time for French and German Prices



(5). In addition to the *constant conditional correlation*, we suppose the error term to be normally distributed for simplicity reasons and to ensure the stability of our model throughout the numerous counterfactual. We release the errors normal distribution hypothesis in the robustness test presented in Table 2.

Although our sample data cover a rather limited number of years, one could argue that the 2012–2015 period was subject to several exogenous shocks. For example, North-Western European power market launched a price coupling in February 2014 and the allocation of the interconnections capacity changed to the flow-based method in May 2015 (c.f. explanation in footnote 6). In order to assess if these shocks generated structural breaks, we implement a residual based cumulative sum test (for more details see Lee and Lee, 2014) that challenges the following hypothesis:

$H_0 : \theta_i = (\omega_i, \alpha_i, \beta_i)$ in constant for the whole series

$H_1 : \theta$ is varying

The flexibility of this test allows us to test for multiple structural break simultaneously. Figure 4 reports the residual CUSUM statistic as well as the threshold corresponding to the critical value at the nominal level 0.05. It appears that we cannot reject H_0, which means that our parameters are stable for the entire period of our analysis.

5. RESULTS

5.1 Impact of renewables on power price dynamics

Table 2 reports the results for our main specification (column 1) as well as several sensitivity tests on the specification. As we expected, demand has a positive and statistically significant effect on prices, both in France and Germany. Our results are in line with previous studies (Jonsson et al. (2010), Woo et al. (2011) Benhmad et al. (2013) and Ketterer (2014)), which found that domestic wind generation has a negative impact on electricity prices in the same market. Increasing domestic wind production by 1% would decrease prices by 0.052% in Germany and by 0.046% in France, on average.

We can extend this result to the neighboring market by looking at the impact of French wind on the German market and vice versa. A 1% increase in domestic wind production will decrease the average price of the neighboring market between 0.01% and 0.02% even though the impact of foreign wind in France is not significant in (1)[10]. Column (2) shows wind production as a proportion of total consumption. An additional percentage point of wind production will decrease the domestic price by 1.3%–2.4% and the neighboring country's price by 0.3–1.4%. Contrary to column (1), results of column (2) indicate statistically significant results for the impact of German wind production on the level of French prices. Since wind generation still accounts for a relatively low proportion of the power generation mix, the results are of greater magnitude. On average, an additional percentage point in the proportion of wind production equates to roughly 550 MWh in both countries whereas a 1% increase of absolute wind production is associated with a much smaller increase (60MWh in Germany and 20MWh in France).

The Panel B of Table 2 reports the conditional variance estimation: both α and β are significant, positive, and their sum is less than one. The relatively small size of α and β means that both past and new shocks have limited effects on conditional variance. Looking at the effect of wind production, it seems that our results confirm previous studies. Over the sample period German wind generation tends to increase national spot price volatility. First, we extend these results to French data: the effect of French wind generation is, as expected, to increase domestic price volatility. Second, we estimate the cross-border impact of wind production on the neighboring country's price volatility. As we expected, French and German renewable generation increase price variance in their respective neighboring market[11]. In addition, we estimate a conditional correlation of 0.67 between French and German prices.

Table 2 also reports several robustness checks on the specification form. Columns (3) and (4) specifically test the robustness of the conditional variance estimation. The available transmission capacity can change based on the number of long term contracts and security standards. The available transmission capacity (ATC) is determined by TSOs in order to keep some safety margin on the interconnection. Column (3) reports results when controlling for ATC: wind effects remain the same but increasing the available capacity would marginally decrease volatility in both countries and increase price level in Germany. We further test the impact of interconnection capacity in the next section. In specification (4) we replace in the variance equations the average daily wind production by the daily standard deviation in order to investigate whether intraday wind volatility is important. It appears that wind daily volatility has a positive and significant impact on price variance both domestically and abroad.

Column (5) reports the results where all our daily variables were aggregated using a consumption weighted average instead of a simple arithmetic mean. It seems that our aggregation methodology generated very similar results compared to a weighted average, so that we can safely

10. On our main specification the impact of the foreign wind appears rather small and sometimes not statistically different from zero. Results in section 5.2 show that this result becomes much bigger and statistically significant when interconnection size increase.

11. Like results in Panel A, some foreign wind production are non-significant (e.g. French Wind on German price volatility). Results in section 5.2 are getting more significant as we increase the interconnection size.

Table 2: Impact of wind production on domestic and foreign electricity markets

Panel A

	Mean equation					
	(1)	(2)	(3)	(4)	(5)	(6)
France	main	share	atc	sd	weighted	t-dist
Domestic Wind	–0.046***	–2.395***	–0.052***	–0.054***	–0.046***	–0.043***
	(0.006)	(0.253)	(0.006)	(0.005)	(0.006)	(0.005)
Foreign Wind	–0.008	–0.337***	–0.011*	–0.010*	–0.008	–0.015***
	(0.005)	(0.062)	(0.005)	(0.005)	(0.005)	(0.004)
Consumption	0.443***		0.454***	0.398***	0.453***	0.365***
	(0.032)		(0.034)	(0.033)	(0.032)	(0.024)
ATC			0.0004			
			(0.044)			
Constant	–0.852**	0.772***	–0.732**	–0.937***	–0.896***	–0.532***
	(0.032)	(0.097)	(0.342)	(0.134)	(0.133)	(0.100)
Germany						
Domestic Wind	–0.052***	–1.312***	–0.061***	–0.064***	–0.054***	–0.058***
	(0.004)	(0.077)	(0.005)	(0.005)	(0.005)	(0.004)
Foreign Wind	–0.019***	–1.390***	–0.026***	–0.028***	–0.019***	–0.027***
	(0.006)	(0.236)	(0.005)	(0.006)	(0.006)	(0.005)
Consumption	0.486***		0.489***	0.428***	0.507***	0.371***
	(0.039)		(0.043)	(0.039)	(0.039)	(0.032)
ATC			0.301***			
			(0.055)			
Constant	–1.137***	1.275***	–3.123***	–1.118***	–1.251***	0.618***
	(0.193)	(0.092)	(0.460)	(0.193)	(0.193)	(0.161)

Panel B

	Conditional variance equation					
France	(1)	(2)	(3)	(4)	(5)	(6)
α	0.139***	0.148***	0.176***	0.184***	0.141***	0.239***
	(0.032)	(0.029)	(0.043)	(0.033)	(0.032)	(0.050)
β	0.104***	0.109	0.035	–0.001	0.119*	0.109
	(0.075)	(0.296)	(0.056)	(0.069)	(0.071)	(0.084)
Domestic Wind	0.452***	16.19***	0.485***		0.442***	0.339***
	(0.096)	(6.058)	(0.092)		(0.095)	(0.121)
Foreign Wind	0.268***	2.680***	0.191***		0.261***	0.480***
	(0.060)	(0.860)	(0.072)		(0.060)	(0.085)
Consumption	–3.193***		–3.891***	–3.020***	–3.204***	–3.411***
	(0.348)		(0.413)	(0.331)	(0.348)	(0.435)
ATC			–0.902**			
			(0.400)			
Domestic sd_Wind					0.443***	
				(0.147)		
Foreign sd_Wind				0.155***		
				(0.033)		
Constant	8.726***	–4.790***	18.56***	8.357***	8.779***	9.509***
	(1.438)	(0.606)	(3.239)	(1.383)	(1.444)	(1.809)
Germany						
α	0.139***	0.119***	0.131***	0.473***	0.134***	0.215***
	(0.030)	(0.028)	(0.034)	(0.066)	(0.030)	(0.051)
β	0.309***	0.108*	0.189***	0.176***	0.319***	0.253***
	(0.043)	(0.056)	(0.054)	(0.035)	(0.044)	(0.065)

(continued)

Table 2: Impact of wind production on domestic and foreign electricity markets *(continued)*

	Panel B *(continued)*					
	Conditional variance equation					
Germany	(1)	(2)	(3)	(4)	(5)	(6)
Domestic Wind	1.245***	8.588***	0.459***		1.181***	1.036***
	(0.096)	(0.414)	(0.085)		(0.096)	(0.125)
Foreign Wind	0.031	0.878	–0.006		0.039	0.171
	(0.091)	(2.128)	(0.088)		(0.222)	(0.121)
Consumption	–5.551***		–5.422***	–5.056***	–5.144***	–3.540***
	(0.423)		(0.435)	(0.525)	(0.415)	(0.486)
ATC			–3.508***			
			(0.399)			
Domestic sd_Wind					0.565***	
				(0.052)		
Foreign sd_Wind				0.106		
				(0.091)		
Constant	16.22***	–5.130***	43.17***	15.22***	14.67***	8.743***
	(1.643)	(0.18)	(3.401)	(2.119)	(1.617)	(1.904)
Cond. corr.	0.672***	0.730***	0.677***	0.665***	0.672***	0.741***
	(0.016)	(0.013)	(0.017)	(0.016)	(0.016)	(0.015)
Observations	1,380	1,380	1,154	1,380	1,380	1,380
BIC	–2993	–3045	–2549	–2743	–3014	–3394
Seasonal FE	YES	YES	YES	YES	YES	YES

Robust standard errors in parentheses
*** $p<0.01$, ** $p<0.05$, * $p<0.1$

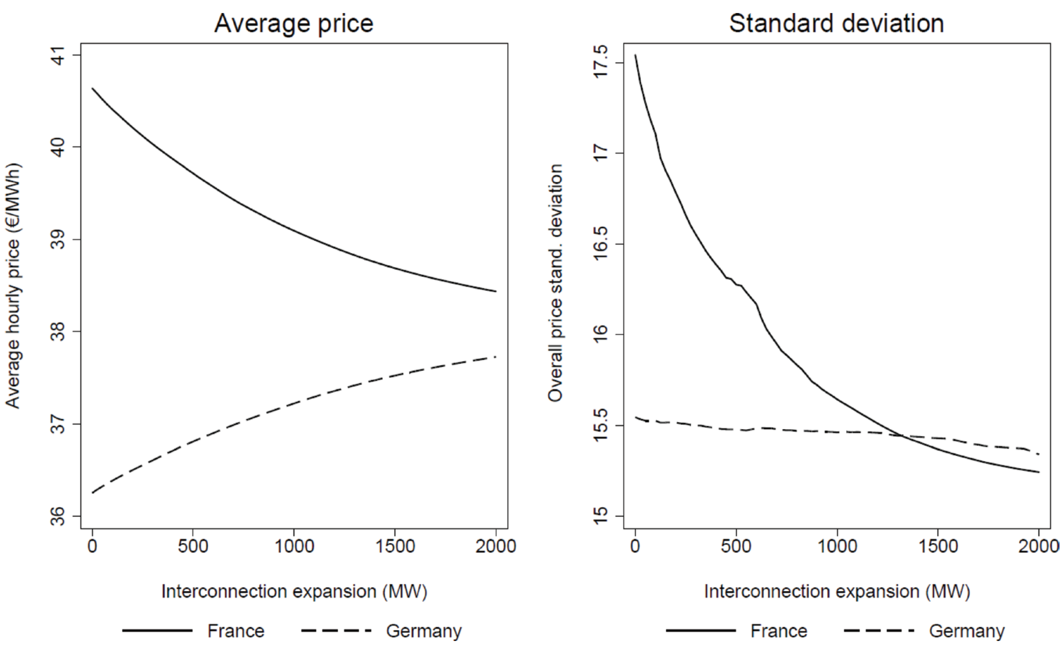
state that aggregation weights do not matter for such estimations. Finally column (6) releases the assumption of error-term normality, using a student's t-distribution instead. Our main results still hold but the magnitude is changing for certain variables, in particular the impact of wind production on French volatility has significantly increased. Our specification (1) is stable and much easier to estimate which is a valuable feature for our next analysis: the effect of interconnection size which necessitates repeated estimations of different price scenarios.

Our results confirm the first research hypothesis, namely that *intermittent wind generation simultaneously impacts domestic and foreign electricity prices.* From a public policy point of view this is an important result. The substantial development of intermittent renewables in Germany has a significant impact on power prices in France, as it decreases the average electricity price but also increases volatility. One potential mitigating factor for this increased volatility could be to increase interconnection capacity; the intuition is that by enlarging the market the volatility generated by intermittent renewable energy would be dispersed. The next section investigates this issue.

5.2 The impact of increased interconnection capacity

By enlarging the size of the market, larger interconnection capacity should decrease price volatility in both French and German markets due to smoother supply and demand curves. However, as we saw in section 5.1, German wind generation has a positive effect on price variance in France, therefore increasing the interconnection capacity could potentially reinforce the impact of wind-induced volatility in France. These two forces act in opposite directions and the overall net effect is not easily predictable. In order to identify which effect dominates, in section 5.1 we used the available

Figure 5: Electricity price volatility and average value in France and Germany for different interconnection capacities over the period 2012–2015

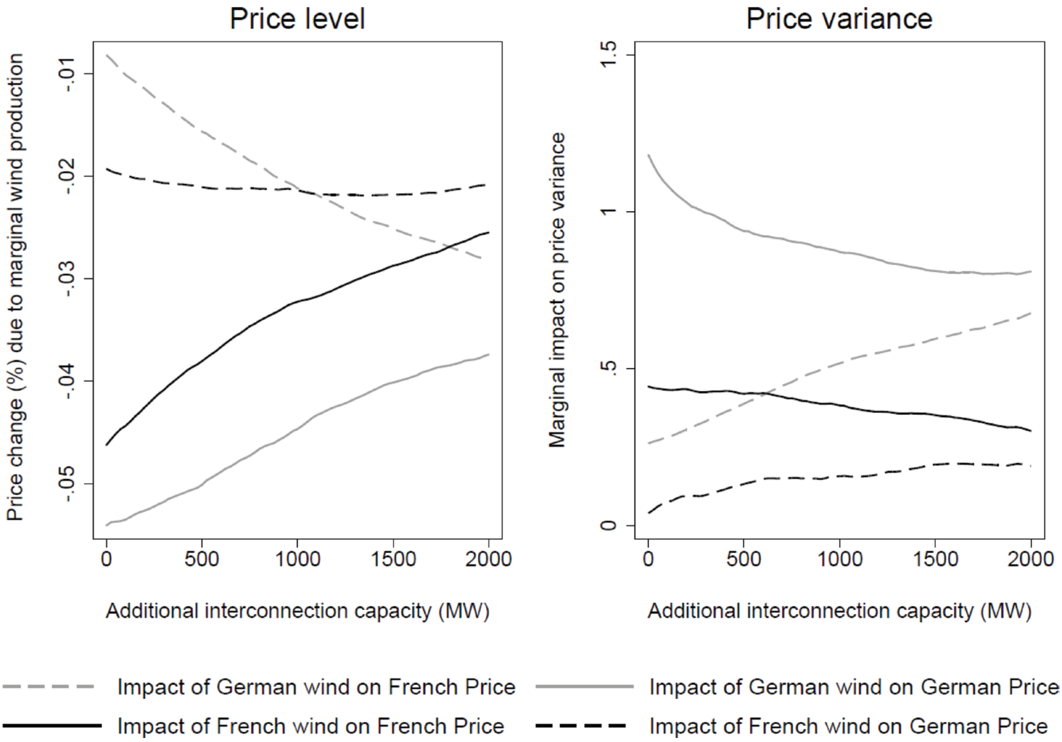


transfer capacity (ATC) as an explanatory variable in the conditional variance equation. The results confirmed our intuition, namely that ATC has a significant negative impact on volatility.

To go one step further, we used the spot market operator order book data of market resilience and recreated artificial time series accounting for interconnection expansions up to 2000MW as described in section 3. Figure 5 reports the overall average price and standard deviation for each time series with 25MW incremental steps of additional interconnection capacity. We observe a reduction in French price volatility whereas German price volatility does not seem to be much affected. A 2000 MW interconnection expansion would decrease volatility in France by about 13%. The impact on the average price is in line with international trade theory, as the country with the highest electricity price imports more when interconnection capacity is greater. An expansion of 2000 MW would have decreased the average price spread from €4.38 to 70 cents. This result is relevant to policy debates: even if Germany is "exporting" the volatility generated by its wind production to France, the overall effect of market integration is actually a reduction of both price volatility and the spread of average prices.

By increasing cross-border capacity we expect wind production to have a higher impact on the neighboring market and a lower impact on the domestic market. To estimate what would be the effect of an expansion of interconnection capacity we applied our main specification—column (1) of Table 2—to the time series obtained from the market order book resilience data. Figure 6 reports changes in coefficients associated with wind production for different levels of interconnection capacity expansion. Increasing the interconnection capacity amplifies the impact of wind on foreign markets and lowers the magnitude of the domestic effect. The *Domestic_wind* betas increase in the mean equation and decrease in the variance equation, meaning that a larger interconnection would lower both the average depressive effect (absolute value of beta decreases) and the volatility impact on the domestic market. On the contrary, when interconnection capacity increases *Foreign_wind* betas become lower in the mean equation and higher in the variance equation. This means that the

Figure 6: Effect of wind generation when interconnection capacity is increased



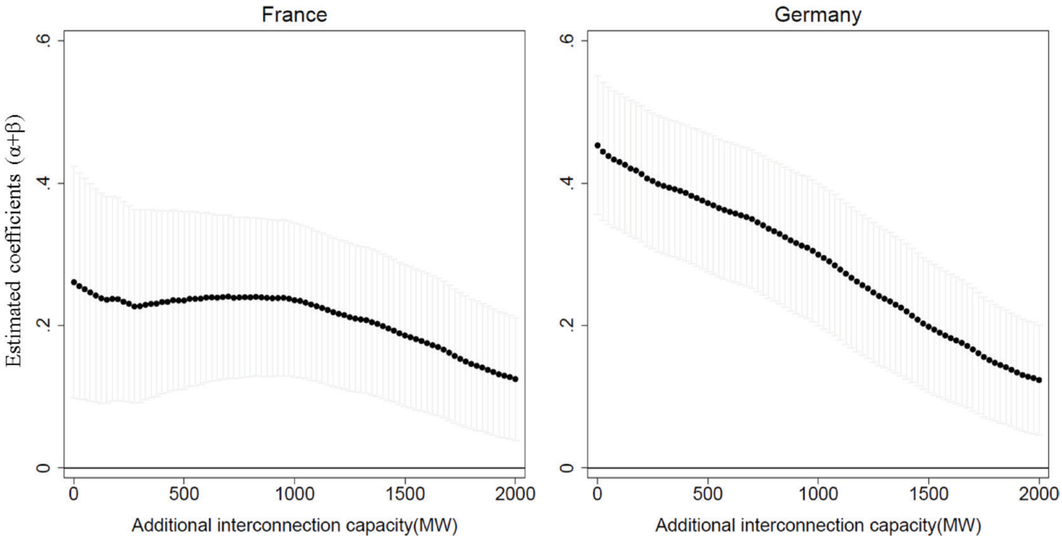
absolute value of the depressive effect as well as the impact on volatility increase with interconnection capacity, i.e. there is a "transfer" of the wind generation effect towards the neighboring market.

More detailed results are shown in the Appendix: Figure A1 reports each coefficient with a 95% confidence interval. Note that in our baseline (column (1) of Table 1) German wind production has a depressive impact on French prices but the effect is not statistically different from zero at the 95% confidence level. Similarly, German wind in (1) has a statistically non-significant impact on the French price level. However, as the interconnection capacity increases, this effect gets bigger and an expansion of 500MW would be sufficient to state with statistical confidence that German wind production is lowering the average French electricity price (see Figure A1). Our 2nd research hypothesis is confirmed, namely that *Increasing interconnection capacity intensifies the impact of intermittent wind generation on the neighboring market and lowers the effects domestically*.

In addition, we find that consumption's effect in absolute value is decreasing in both countries when interconnection capacity increases. This result confirms the intuition that increasing market integration would smooth the overall supply and demand curve. The more markets are connected, the less a marginal shock on the domestic demand will have an effect on the domestic spot prices.

One could argue that the theoretical capacity of the interconnection is different from the transmission capacity that is actually available in real time—the available transmission capacity (ATC). Indeed, TSOs can limit ATC preventively in order to maintain the safe operation of their domestic system. In practice, the ATC does indeed vary between Germany and France and a 1000 MW physical interconnection capacity expansion would not have the same impact for an ATC of 500MW or 3000MW. Over the period 2012–2015 our historical data for France and Germany show

Figure 7: Price volatility past shock persistence in France and Germany when interconnection capacity is increased



that, on average, the hourly ATC available for exports from the low price country to the high price country was around 1750MW with a standard deviation of 220[12].

Finally, one interesting feature of GARCH models is the estimation of shock persistence. The parameters α and β capture the effect of past shocks and the variance's autocorrelation, respectively. The sum of these two parameters is always smaller than 1, which ensures the stability of the conditional variance. In addition, our results show that increasing the interconnection capacity would reduce the impact of shocks in both countries. Figure 7 shows how quickly the sum of alpha and beta decreases when the expansion of the interconnection. With 2000MW additional capacities, the magnitude of a past shock impact on the current volatility would roughly be divided by two in France and by three in Germany.

6. POLICY DISCUSSION

Our empirical findings in this paper raise a number of questions relevant to policy.

First, our empirical results confirm findings from previous studies about the depressive effect of renewables—and more specifically wind power—on average short-term power prices, as well as the increase in power price volatility. Policies supporting wind power generation put downward pressure on power prices and, therefore, risk creating a vicious circle by preventing renewables from becoming competitive based on wholesale market revenues. This is compounded by the increase in price volatility, which may undermine investment given the typical risk aversion of investors in electricity markets unless risk-hedging products are developed (Meunier, 2014). This implies that there may be a structural and permanent need for subsidies for wind power—or at least de-risking mechanisms such as long term contract for difference.

Moreover, the depressive effect on wholesale prices and the increase in price volatility associated with wind power deployment can undermine investment in other types of technologies and lead to a suboptimal generation mix given the risk aversion of typical investors in electricity

12. A histogram of the series is available in the Appendix

markets—particularly for peaking plants (Roques et al., 2008). This can create the need for complementary mechanisms such as capacity remuneration mechanisms, which have been implemented in many European countries in the past few years.

Second, our empirical findings demonstrate that in an integrated power market such as that in Europe, national policies supporting wind generation have a significant impact on cross-border power prices both in terms of average level and volatility. This in turn affects prices for consumers on the other side of the border as well as the profitability of other types of generation. Our findings therefore highlight an inconsistency in current European energy policy as support policies to renewables remain largely determined on a national basis without accounting for cross border effects, while power markets are increasingly integrated. Our results suggest that EU member states should improve the coordination of renewables support schemes on a regional basis so that their impact on power markets is managed in an integrated way across borders.

Finally, our empirical findings raise questions regarding the need for and benefits of additional interconnection capacity. There is a widespread belief in Europe that there would be significant benefits in having a greater degree of interconnection between electricity markets, estimated to range between €12.5 and €40bn/year in 2030 (Newbery et al., 2016). However, this does not mean that all interconnection projects would be socially beneficial and the selection of projects receiving public support needs to be based on a cost-benefit analysis. Whilst typical impact assessments investigate the consumer welfare impact of further price convergence, they often fail to take into account the national targets for RES deployment in a dynamic way. As our research demonstrates, these can significantly affect power price dynamics on both sides of the border and affect the economic impact of new interconnections. Although there is a contagious marginal impact of the wind production, the overall absolute effect is a reduction of the price volatility in both countries as well as a reduction of the price spread.

7. CONCLUSION

There a number of questions about the consistency of the twin European objectives of deploying large quantities of renewables and integrating power markets, in particular the impact of renewables on power market dynamics. Our paper confirms the results from the existing literature: on average, wind generation depresses power prices and increases price volatility. In addition, to the best of our knowledge, our paper is the first to assess the impact of increased wind capacity in neighboring countries, using a Franco-German case study. We also used empirical market resilience data from the spot market operator to simulate the effect of intermittent wind generation on cross-border power prices for different levels of additional interconnection capacity between France and Germany.

Our results show that between 2012 and 2015, an expansion in interconnection capacity of 2000MW would have decreased the volatility in both French and German markets and reduced the price spread by €3.68. Looking at the descriptive results alone would therefore support further development of interconnection and greater market integration. However, the econometric results also show that increasing interconnection capacity would have transferred some of the volatility generated by wind production from one country to another. Even if the price variance decreases when interconnection capacity is greater, the price variance is also more sensitive to wind generation. This means that if Germany continues its massive development of intermittent wind generation, the overall effect of greater interconnection capacity could potentially overwhelm the positive effect of interconnecting markets for France.

Our findings are therefore relevant to the current policy debate as they demonstrate the need to coordinate cross-border support policies for renewables on a regional basis between neighboring countries when markets are integrated.

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APPENDIX

Figure A1: Detailed changes in the impact of wind production on domestic and foreign prices with varying interconnection capacities (MW).

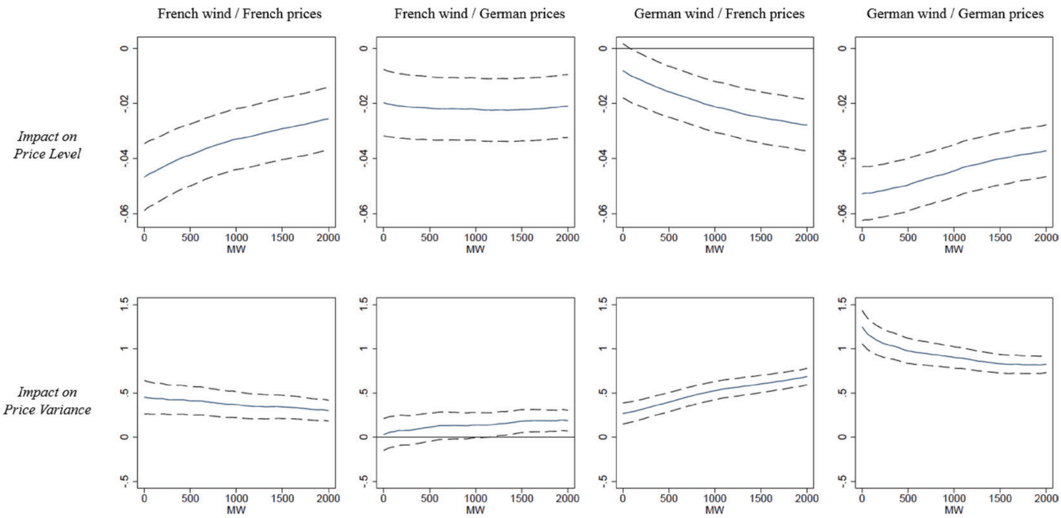

Figure A2: Histogram of hourly available transfer capacity over the 2012–2015 period