On the Impact of Wind Feed-in and Interconnections on Electricity Price in Germany

Abstract

In this paper, we explore carry out an empirical analysis for Germany, as a country with high penetration of wind energy, to investigate the interaction between the well-known merit-order effect, i.e., falling spot price levels as well as highly fluctuating spot prices and the European electricity grids inteconnections,i.e., market coupling.

Our main empirical findings suggest that wind power in-feed decreases electricity spot price level but increases spot prices volatility. Furthermore, the relationship between wind power and spot electricity prices can be strongly impacted by European electricity grids interconnection which behaves like a safety valve lowering volatility and limiting the price decrease. Therefore, the impacts of wind generated electricity on electricity spot markets are less clearly pronounced in interconnected systems.

Keywords: RES, Electricity spot prices, merit order effect, volatility.

JEL classification: Q41, Q42, Q48

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1. Introduction

Renewable energy is a key component of the EU energy strategy. It started with the adoption of the 1997 White paper and has been driven by the need to de-carbonise the energy sector and address growing dependency on fossil fuel imports from politically unstable regions outside the EU. To achieve this goal, the European Union has aimed to have at least 21% of its electricity coming from renewable energy sources by 2020.

The Renewable Electricity Directive 2001 gives EU Member States freedom of choice regarding support mechanisms. Thus, various schemes are operating in Europe, mainly feed-in tariffs, fixed premiums, green certificate systems and tendering procedures. These schemes are generally complemented by tax incentives, environmental taxes, contribution programs or voluntary agreements.

Wind and solar power are the forms of renewable power that are expected to grow most rapidly. They accounted for more than 35% of EU renewable capacity in 2010, a percentage that the IEA in *World Energy Outlook 2011* expects to increase to 55% in 2015 in its central 'new policies' scenario. By 2030 the IEA expects wind and solar to constitute 34% of total EU electrical capacity.

Germany is one of the world leaders in wind power and, with 39.2 GW of installed capacity by 2014, is currently in third place in the international rankings behind China and the USA. Moreover, Germany remains the EU country with the largest wind energy installed capacity.
Wind power already contributed 9.1 percent to electricity consumption in 2014. In 2014, solar PV electricity accounted for 5.7 per cent of gross electricity production in Germany. All renewable sources combined made up 26.2 per cent of gross electricity production in 2014 and are Germany’s second most important source of electricity generation after lignite (BDEW, 2015). The German Renewable Energy Act, ”Erneuerbare-Energien-Gesetz” (EEG),

a well known support scheme, has provided a favorable feed-in tariff (FIT) for a variety of renewable energy sources (RES) since the year 2000. It also gives priority to electric power in-feed from RES over power in-feed from conventional power plants, i.e., fossil- and nuclear-fuel thermal and already existing hydro-based power plants.

Germany has coupled its electricity markets respectively with Denmark in 2009, with Sweden in 2010. In November 2010, the countries of the CWE region (Belgium, France, Germany, Luxembourg and the Netherlands) and the Northern region (Denmark, Sweden and Norway) coupled also their electricity markets allowing flows of electricity toward and from neighboring countries. To reach this goal, the interconnections should play a central role in integrating all European electricity markets into one unique market. Indeed, commercial exchanges are established taking advantage of the energy price differences between electricity systems, making it possible for electricity to be generated using the most efficient technologies and allowing energy to be transported from where it is cheaper to where it is more expensive.

The goal of this paper is carry out an empirical analysis for Germany to investigate the well-known merit-order effect, i.e., falling spot price levels due to RES especially the wind feed-in. Moreover, we explore the interaction between market coupling (grid interconnections) and merit order effect and the outcome of this interaction on electricity spot prices and their respective volatility.

Indeed, one of the central empirical findings in the literature on renewable energy (RE) is that an increase in intermittent sources generation would put downward pressure on the spot electricity market price by displacing high fuel-cost marginal generation. RE installations, although they are very capital-intensive, have almost zero marginal generation cost and thus are certainly dispatched to meet demand. More expensive conventional power plants are crowded out, and the electricity price declines. This is called merit-order effect (MOE).

It is worth noting that several authors have explored this topic. For Germany, Bode and Groscurth (2006) find that renewable power generation lowers the electricity price. Neubarth et al. (2006) show that the daily average value of the market spot price decreases by 1 €/MWh per additional 1,000 MW wind capacity. Sensfuss et al. (2008) show that in 2006 renewables reduced the average market price by 7.83 €/MWh. Weigt (2008) concludes that the price was on average 10 €/MWh lower. Nicolosi and Fürsch (2009) confirm that in the short run, wind power feed-in reduces prices whereas in the long run, wind power affects conventional capacity, which could eventually be substituted. For Denmark, Munksgaard and Morthorst (2008) conclude that if there is little or no wind (<400MW), prices can increase up to around 80 €/MWh (600 DKK/MWh), whilst with strong wind (>1500MW) spot prices can be brought down to around 34 €/MWh (250 DKK/MWh). Jonsson et al. (2010) show that the average spot price is considerably lower at times where wind power production has been predicted to be large. Sáenz de Miera et al., (2008) found that wind power generation in Spain would have led to a drop in the wholesale price amounting to 7.08 €/MWh in 2005, 4.75 €/MWh in 2006, and 12.44 €/MWh during the first half of 2007.

There are three main contributions of this study to the literature. Firstly, we use a more recent data sample by using daily data for the period 2009-2013 which allows us to assess more accurately the learning effect. Secondly, we carry out an AR-X- GARCH-X modeling, where the wind generation and grids interconnection’s variable- proxied by the Germany- France prices differential (spread) - are assumed to be exogenous variable included in the mean and the variance equation, in order to assess their joint impacts on the electricity spot price level as well as on spot price volatility in Germany. Thirdly, this paper attempts to explore the policy implications of the empirical results.

Our main findings suggest that intermittent wind power generation does not only decrease the spot electricity price in Germany but also increases the price volatility. However, the downward effect of the feed-in of wind-generated electricity on spot prices and the upward effect on price volatility are limited by the possibility of exporting part of the surplus wind power to Germany’s neighbours (including France). The negative impact of RES on electricity spot market prices and their volatility are thus made less pronounced by interconnections.

The paper is organized as follows. Section 2 provides an overview of the merit order effect. In section 3, we carry out an empirical analysis and in section 4 we discuss the main findings. Section 5 provides some concluding remarks.

2. The merit order effect:

Power generation technologies generally compete with each other in electricity markets to supply electricity through a ‘merit order’ based on availability and marginal cost of production for any given period. Fossil fuel, nuclear, biomass and hydro power generators can be called upon or adjusted to meet demand.

Depending on the plants present in the power system, the system operator can plan which generating units will be used to meet the expected net load demand at each point of the coming day. One approach is to rank the units in the system in ascending order of their marginal cost of generation (the cost incurred by producing one additional kilowatt-hour), known as *a merit order*. (Sioshansi,2013).

Traditionally, this means hydroelectric power plants are the first to be dispatched on the grid. They are followed by nuclear plants, and then coal-fired and/or combined-cycle gas turbines (CCGT). Since coal price in Europe is low due to US surpluses exports, and given the extremely low price of CO_2 on the European carbon market, the higher price of gas due to oil indexation of gas contracts, coal-fired plants are generally dispatched before the gas turbine. Next come open cycle gas turbine (OCGT) plants and oil-fired units with the highest fuel costs. Therefore, during full and peak times, the marginal power plant is logically a combined-cycle gas-fired plant.

Electricity prices on the spot market are higher during peak hours, when demand may exceed the maximum supply levels that the electrical power plants can generate, resulting in power outages and load shedding. Gas turbines or combustion turbines operating with diesel fuel are called to meet peak demand; they use expensive fuels and emit higher carbon pollution.

Therefore, electricity producers have to recover the fixed costs of baseload power plants (e.g., hydroelectric and nuclear) during peak hours.

Indeed, selling a nuclear KWh based on the gas turbine’s marginal cost at peak hours is the means to retrieve a markup for covering the nuclear fixed costs because nuclear plants are typically price takers in markets where marginal prices are set by more expensive peaking units.

In a competitive market, assuming the power generation fleet is optimal, the selling price allows the recovery of the full fixed and variable costs of the infrastructure used if the pricing is based for each period - off-peak hours, full hours, peaks hours- on fleet’s marginal costs. At peak hours, variable and fixed costs of peaking plants, such as gas turbines, must be covered.

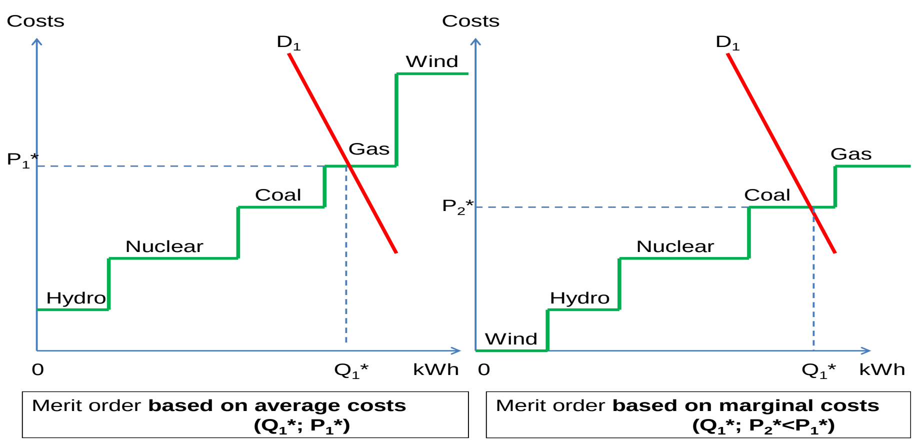
At off-peak hours, only the variable costs of the marginal plants must be covered; sometimes it will be a coal-fired plant, and at other times it may be a nuclear plant.

However, as renewable energy sources (RES) have no fuel costs, they have a zero marginal cost. Thus, electricity from RES makes the coal-fired plant becoming the marginal plant. The electricity market price is thus lower than it would be if there was no RES power in-feed.

Indeed, if the wind or solar power plants were not remunerated according to feed-in tariffs scheme they could never be profitable because the spot market price at full and peak periods would not allow them to recovery their fixed costs.

The following Figure 1 shows the merit-order curve based respectively on average and on marginal costs.

Figure 1. Merit order based on average and marginal costs



3. Empirical evidence:

In this empirical section, we carry out an empirical analysis for Germany in order to explore the most evidenced stylized fact of RES impact on spot electricity prices: the merit order effect and the interaction of the European grid interconnections (market coupling) with this impact. Moreover, we carry out an analysis of the joint effect of wind feed-in and grid interconnections on electricity prices volatility.

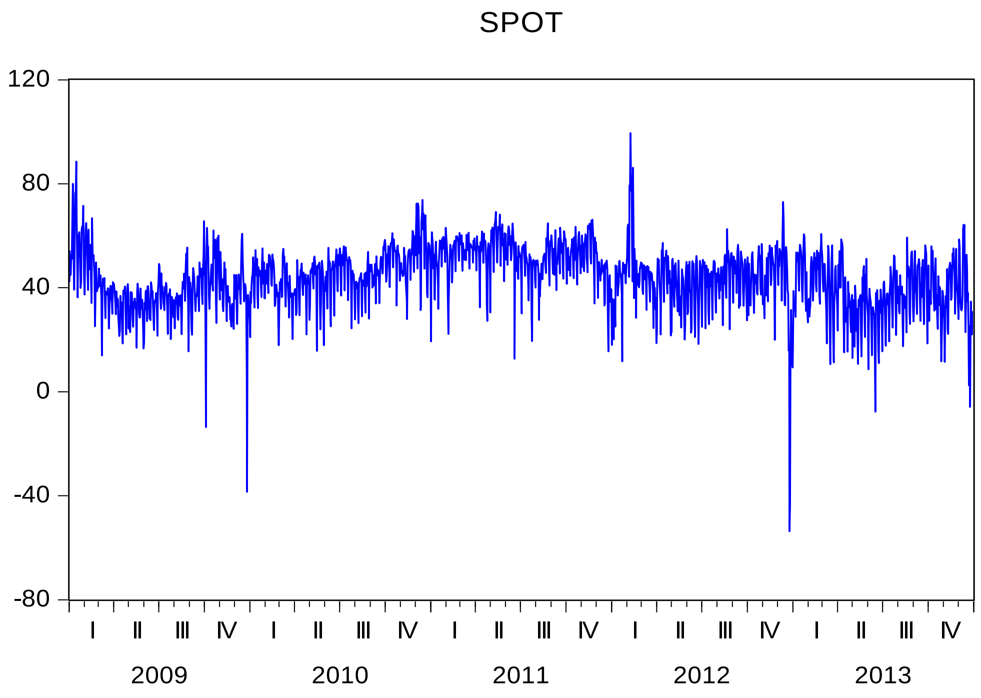
3.1 Data

3.1.1 Electricity baseload price

The sample data covers daily electricity baseload spot price during the period going from the 1st January 2009 to the 31st December 2013, summing up to 1826 observations.

Figure 2 provides a plot of the data for the whole period. It is easy to see that the data exhibits the typical features of electricity prices and contains several periods of extreme volatility, price spikes and shows a mean-reverting behavior.

Figure 2. Daily EEX day-ahead spot prices (€/ MWh)



The descriptive statistics of German electricity spot prices summarized in Table 1 show that values of sample mean are close to 43.57 and a standard deviation of 12.10.

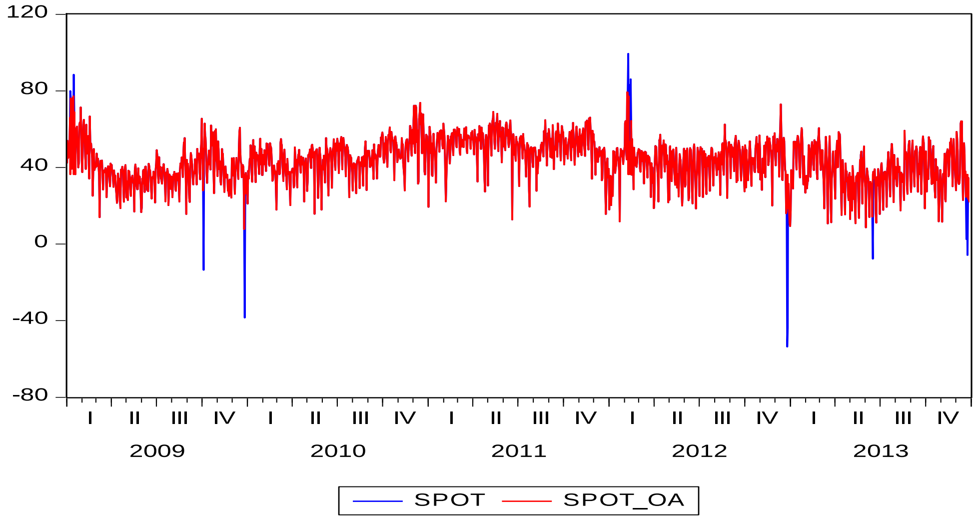
Table 1 Descriptive statistics of German electricity spot prices.

Observations	1826
Mean	43.50
Std.Dev.	12.10
Skewness	-0.84
Kurtosis	8.34
Jarque-Bera	2394.22
Prob.	0.0000

The sample kurtosis (8.34) is higher than 3, the kurtosis of a normal distribution, implying that price distribution exhibit fat tails. Furthermore, negative skewness indicates a greater probability of large falls in electricity price than large increases. The p-value of Jarque- Bera statistic induce a rejection of the electricity prices normal distribution null hypothesis.

As electricity spot prices deviates from the normal distribution due to more frequent large outliers, outliers should first be removed before conducting the regression analysis. In line with the literature, we remove values that exceed three times the standard deviation of the original price series as shown by Figure 3. The outliers are then replaced with the value of three times the standard deviation.

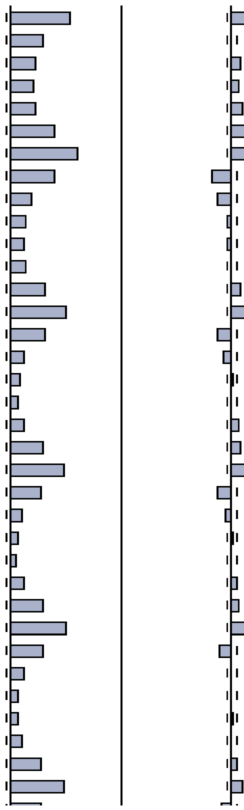
Figure 3. Outliers adjustment of spot electricity prices



Correlogram analysis of electricity prices (see figure 4) shows a strong autocorrelation in lags 7,14,21, 28 which implies a weekly seasonality. Indeed, the typical seasonal pattern of electricity spot prices during the weekdays, holidays and week-ends is very obvious according to the demand variability. The daily electricity spot prices decrease progressively from Monday to the week-end and are lowest on Saturday.

Figure 4. Correlogram of electricity prices

Sample: 1/01/2009 12/31/2013
Included observations: 1826



	AC	PAC	Q-Stat	Prob
1	0.552	0.552	556.53	0.000
2	0.309	0.007	731.26	0.000
3	0.235	0.089	832.46	0.000
4	0.217	0.075	918.51	0.000
5	0.242	0.114	1026.1	0.000
6	0.415	0.320	1342.3	0.000
7	0.634	0.439	2079.8	0.000
8	0.404	-0.173	2379.3	0.000
9	0.200	-0.118	2452.8	0.000
10	0.138	-0.037	2487.9	0.000
11	0.119	-0.032	2513.8	0.000
12	0.146	-0.000	2553.0	0.000
13	0.315	0.095	2735.6	0.000
14	0.523	0.206	3239.6	0.000
15	0.313	-0.130	3420.5	0.000
16	0.125	-0.066	3449.2	0.000
17	0.087	0.023	3463.1	0.000
18	0.070	-0.007	3472.3	0.000
19	0.124	0.069	3500.8	0.000
20	0.296	0.086	3663.0	0.000
21	0.515	0.192	4153.8	0.000
22	0.292	-0.132	4311.2	0.000
23	0.106	-0.050	4331.9	0.000
24	0.073	0.013	4341.9	0.000
25	0.062	0.000	4348.9	0.000
26	0.119	0.047	4375.1	0.000
27	0.299	0.075	4540.9	0.000
28	0.521	0.157	5044.3	0.000
29	0.296	-0.103	5206.8	0.000
30	0.120	-0.003	5233.7	0.000
31	0.081	-0.000	5245.9	0.000
32	0.074	0.020	5256.0	0.000
33	0.113	-0.006	5279.6	0.000
34	0.295	0.055	5441.5	0.000
35	0.507	0.100	5919.6	0.000

A monthly seasonality, not as strong as weekly seasonality, is also detected. This seasonal pattern modeling by dummy variables seems to be more appropriate. Demand varies throughout the day and during the week, as well as across the year. Therefore, models of electricity prices should incorporate seasonality, as exemplified by Knittel and Roberts (2005). Daily dummy variables coefficients show a progressive lowering of electricity spot prices from the beginning to the end of the weeks. The lowest value occurs Saturday. For the monthly dummy variables, although some coefficients are not enough significant, we see a lowering of electricity spot prices during March, April, May, June, July and August.

After outliers removal and seasonal adjustment, we carry out an augmented Dickey-Fuller (ADF) test (Dickey and Fuller,1981) to test for stationarity properties of electricity adjusted spot prices.

Table 2. ADF unit root test on adjusted electricity spot prices

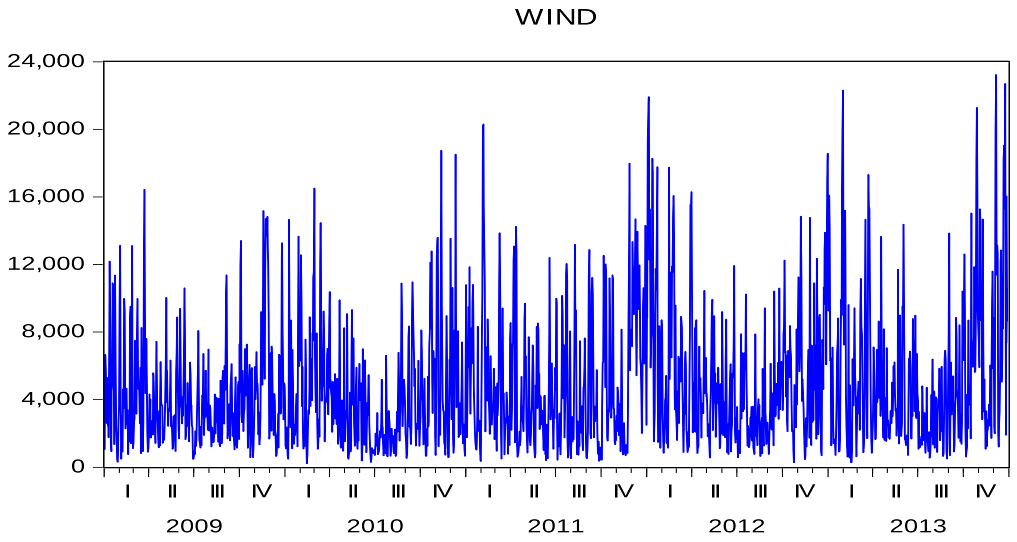
		t-statistic	Prob.
Augmented Dickey-Fuller test statistic		-6.803016	0.0000
Test Critical Values:	1% level	-2.566233	
	5% level	-1.940998	
	10% level	-1.616582	

The ADF t-statistic is -6.8030 whereas the 5% critical value is -1.9410. The null hypothesis of a unit root is rejected, spot electricity prices are then stationary. As electricity is not storable, the price tends to spike and then revert (mean-reverting behavior) as soon as the divergence of supply and demand is resolved (Escribano et al., 2011).

3.1.2 Wind power feed-in

The data we have used are forecasts for daily wind power feed-into the grid system from 1th January 2009 to 31th December 2013 as illustrated in Figure 4.

Figure 5 .Wind power feed-in (2009-2013)



These forecasts are made by the four German transmission system operators (TSO).[1] The descriptive statistics of wind feed-in reported in Table 2 show that the Wind power forecasts fed into the grid has a mean of 4787 MWh per day but a high variability.

Table 3. Descriptive statistics of wind feed-in

Observations	1826
Mean	4787.28
Std.Dev.	3795.48
Skewness	1.50
Kurtosis	5.52
Jarque-Bera	1171.47
Prob.	0.0000

The price distribution exhibits fat tails (excess kurtosis) and the null hypothesis of normal distribution is rejected according to Jarque-Bera statistic.

[1] The data are available in 15-minute format. For this study, 15-minute MW data are averaged for each hour and again averaged to MWh per day. There is four transmission system operators (TSO) in Germany and one TSO in Austria: *Amprion GmbH*, *TenneT TSO GmbH*, *50hertz Transmission GmbH*, *EnBW Transportnetze*, and *APG-Austrian Power Grid AG*.

For the Wind power, the variable shows seasonal dynamics which could be accounted for by using dummy variables. The deseasonnalized time series called (wind_sa) is then tested using the ADF test which reveals their stationary behavior (the ADF t-statistic is -22.1589 whereas the 5% critical value is -1.9410).

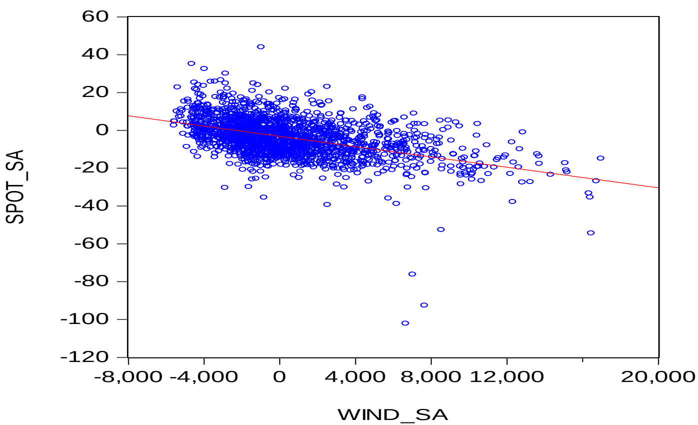
Table 4. ADF unit root test on WIND_SA

		t-statistic	Prob.
Augmented Dickey-Fuller test statistic		-22.15898	0.0000
Test Critical Values:	1% level	-2.566233	
	5% level	-1.940998	
	10% level	-1.616582	

3.1.3 Modeling electricity price and wind in-feed and interconnections link :

First, we begin by testing the existence of the so-called merit order effect, we plot the electricity spot price against the wind feed-in. The following figure 6 shows the decreasing effect (negative slope) of wind power on electricity spot price.

Figure 6. The merit order effect

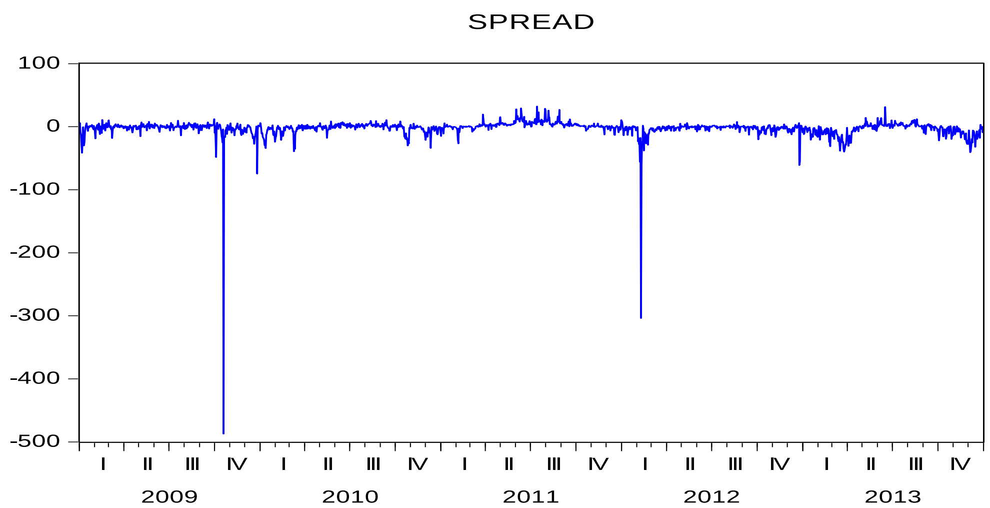


However, the removal seasonality and outliers didn't filter out high order serial correlation from electricity prices as shown by the Durbin-Watson statistic (0.61<2) and Ljung Box test for lags 10 and 20 (LB(10)=3911.4 et LB(20)=5881.9). To filter out theses autocorrelations, we use the methodology of Box and Jenkins (1976) by applying an autoregressive moving average (ARMA) filter of order (p,q).

Therefore, the impact of wind-in feed on spot electricity prices (the merit order effect) is explored according to and ARMA-X model where the wind feed-in considered as an exogenous variable X.

Furthermore, in order to take into account the impact of European grid interconnections on the electricity spot prices in Germany, we use the spread (price differential between Germany and France) as a proxy variable of electricity market coupling. We then use it as an additional explanatory variable in our ARMAX model. The spread dynamics are shown at the following figure 7.

Figure 7. Spread of Germany-France electricity spot prices



Therefore, the ARMA-X model to be tested where the wind feed-in and spread variables are considered as exogenous variables can be written as follows:

$$(spot\_sa)_t = \alpha_0 + \sum_{i=1}^{p} \alpha_i (spot\_sa)_{t-i} + \sum_{j=1}^{q} \beta_j \varepsilon_{t-j} + \delta wind\_sa_t + \eta spread + \upsilon_t (1)$$

The selection of autoregressive lag p could depend on AIC minimization, and moving average is ignored (j=1,…..q is assumed to be 0). According to the Akaike information criterion, the best choice was lag p=7 which corresponds to a weekly seasonality.

The estimation results a reported in Table 5 reveal a negative impact of wind power feed-in on the electricity price in Germany (the so-called merit order effect). In contrast, the market coupling of European electricity markets has a positive effect on electricity spot prices.

Table 5. Impact on electricity prices

Dependant variable : electricity spot prices
Sample : 1.1.2009 31.12.2013

	Mean equation
Constant	-2.48 (0.0558)
Wind	-0.0010 (0.0000)
Spread	0.1316 (0.0000)
	Variance equation
Constant	11.93 (0.0000)
Alpha	0.35 (0.0000)
Beta	0.16 (0.0001)
Wind	0.000460 (0.0000)
Spread	-0.2617 (0.0000)
Adjusted.R squared	0.6930
AIC	5.9385
BIC	5.9839

Note: AIC and BIC stand respectively for Akaike and Bayesian information criterion, p-values are in parentheses.

Indeed, for each additional GWh of wind feed-in, the electricity price decreases by 1 €/MWh at the spot market. This price decreasing effect of wind electricity generation in Germany is more pronounced than previous studies, as we have used a more recent sample data. Therefore, and given the average wind electricity generation during 2009-2013, the merit-order effect roughly corresponds to an average price decrease, in absolute terms, of approximately 5 €/MWh. The grid interconnections allow Germany to manage its oversupply of wind power by exporting to its main big neighbour market (France), thus making the decrease less pronounced (13 centimes Euro/MWh).

As the residuals of linear regression on the mean equation should be homoskedastic according to least squares estimator hypothesis, an ARCH-effect test following the procedure of Engle (1982) should be carried out on residuals of the mean equation (equation 1).

Then, an ARCH-effect test results are reported in Table 6.

Table 6. ARCH heteroskedasticity test on regression residuals

Heteroskedasticity Test: ARCH			
F-statistic	120.83	Prob. F(1,1816)	0.0000
Obs*R-squared	113.41	Prob.Chi-Square(1)	0.0000

We can conclude that residuals of the equation (1) are heteroskedastic. This ARCH effect in the residuals data indicates a time varying volatility dynamics of the electricity spot prices.

In order to capture this time-varying volatility feature, a parsimonious GARCH(1,1) specification (Bolleslev,1986) could be used[2] .

As our goal consists in exploring the joint impact of wind in-feed and European grid interconnections on spot electricity price level and also on price volatility dynamics, the wind feed-in and interconnections (the spread) should be taken into account as exogenous variable in the mean equation as well as in the variance equation. Therefore, our empirical analysis is based on ARMA(p,q)-X-GARCH(1,1)-X modeling where the exogenous variable X represents the wind in-feed and the price spread between Germany and France.

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[2] The GARCH (p,q) model was introduced by Bollerslev (1986). The conditional variance is expressed as $\sigma_t^2 = w + \sum_{i=1}^{p} \alpha_i \varepsilon_{t-i}^2 + \sum_{j=1}^{q} \beta_j \sigma_{t-j}^2$ where $w > 0$; $\alpha_i \geq 0; i = 1,2,......p$; $\beta_j \geq 0, j = 1,2,.....q$ and $[\ \sum_{i=1}^{p} \alpha_i + \sum_{j=1}^{q} \beta_j\ ] < 1$).The most used model in empirical litterature is GARCH (1,1) model where p=q =1 ; $\sigma_t^2 = w + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2$.

According to results reported in table 6, we can see that the GARCH model parameters are positive and statistically significant at the 1% level. The sum of $\alpha + \beta$ is less than one. We can conclude that the introduction of wind electricity in Germany has not only reduced the electricity spot prices (-0.0010), but also induced an increase of their volatility (positive sign +0.00046 at the conditional variance equation).Indeed, wind in-feed, due to the merit-order effect, not only reduces the electricity spot price level making them sometimes negative, but induces an increase of electricity price volatility, exacerbating risks in electricity markets.

In contrast, the reported results show that Germany-France electricity price spread not only increases the German spot electricity price but also lowers its volatility. Indeed, the coefficient of the spread is positive in the mean equation and negative in the conditional variance equation. With a better integrated electricity market, electricity export flows from Germany (low-price country) to France (country where demand and price are higher). Therefore, electricity exports are able not only to partially smooth the German spot price making it less impacted by episodic oversupply of wind-in feed by also to decrease its volatility impacted by wind feed-in huge intermittence.

4. Policy implications

The introduction of wind electricity in Germany has not only reduced the electricity spot prices, but also contributed to an increase in their volatility. However, the challenge of a wind production excess in relation to low demand can be adressed by exporting the electricity production surplus to neighbouring countries. Therefore, the interconnection of the European electricity grids should behaves like a safety valve preventing the full effect of renewable power on the spot electricity price and its volatility.

However, the merit order effect due the RES (wind energy injection is mainly concentrated in the north of Europe) can no longer be offset by interconnections. Indeed, the electricity market coupling used to allocate cross-border capacity cannot totally ensure the contribution of all available flexible sources throughout Europe due lack of grid transport capacity or grid constraints. Therefore, in order to cope with large volumes of intermittent RES, urgent and extensive grid investments are needed. Without, grid investments, the goal of a common European electricity market can never be achieved.

Moreover, as renewable energy sources are weather-dependent; electricity from solar and wind power is only available while the sun continues to shine and the wind to blow.Since wind and photovoltaic energy sources are intermittent, flexible generation plants (thermal or hydro) are necessary to compensate for imbalances between supply and demand. Thus, RES avoids fuel expenses but requires investments to be made in backup capacity (flexible power plants). However, the increasing RES penetration has reduced load factor for conventional generation. Therefore, the ability of existing back-up plants to recover their fixed costs may be weakened and may lead to earlier decommissioning decisions or discourage new investments. Similarly, the increasing uncertainty will send a wrong signal to prospective investors in new conventional generation capacity.

A first solution consists on increasing interconnection capacity in order to “import” backup capacity from abroad, developing energy storage facilities, introducing “smart grids” or a Demand Side Management mechanism.

A second solution based consists on capacity payments outside of the energy market allow the recovering the ‘missing money’ (Stoft,2002).This mechanisms allows a two-part price, with one set of revenues paying for energy on a €/MWh basis and another rewarding capacity needed on a €/MW-period basis.

Another consequence of increasing RES is the high increase of power prices for German household. Back in 2000 an average household consuming 3,500 kwh/a paid €40.67 per month for electricity. By 2011 the same amount of electricity cost €72.78 per month. Electricity price hike for German households should continue in the coming years.

According the feed-in tariff subsidy scheme, producers of renewable electricity in Germany can sell their production at a fixed tariff to grid operators. The grid operators buy the green power and sell it into the markets. They are more than compensated for the losses that they suffer on these transactions. Since 2009, this compensation is based on the difference between overall EEG costs (leveled out for the whole of Germany), and the average year ahead wholesale power price. The compensation is paid by the end-consumers through the EEG-Umlage that they pay on their power bills. German authorities fixes the exact amount every year, which has reached the 6.24 cts/KWh in 2014. The EEG-surchage accounts for approximatively 21.8% of the price for 1 kWh in 2014. The total paid "EEG-Umlage" in Germany alone was almost 17 billion Euros in 2012 and 2013 and estimated almost 20 billion in 2014. The electricity prices for a representative household increas by 81% between 2000 and 2011.

Moreover, the increasing number of exemptions from the surcharge- being granted to the German industrial sector so that the international competitiveness of German companies would not be damaged- results in the remaining, non-exempt consumers paying more, the EEG-surcharge payable per household will climb, the price of electricity is on track to climb still further.

Therefore, the rising costs of renewables are driving low-income households to a fuel poverty trap. In fact, a DIW Report estimates that the poor pay more than double their proportion of income for the EEG Umlage than the rich (Neuhoff et. al 2012).

5. Conclusion:

The German Feed-in tariff, as a renewable energy sources promotion scheme is the most ambitious one in Europe. Germany is one of the world leaders in wind power and, with 39.2 GW of installed capacity by 2014, is currently in third place in the international rankings behind China and the USA. Moreover, Germany remains the EU country with the largest wind energy installed capacity.

In order to evaluate the efficiency of renewable support policies (FIT), we carry out an empirical analysis from 2009 to 2013 where the wind generation and grids interconnection's variable- proxied by the Germany- France prices differential (spread) - are assumed to be exogenous variable included in the mean and the variance equation, in order to assess their joint impacts on the electricity spot price level as well as on spot price volatility in Germany
Our main findings suggest that intermittent wind power generation does not only decrease the spot electricity price in Germany but also increases the price volatility. However, the downward effect of the feed-in of wind-generated electricity on spot prices and the upward effect on price volatility are limited by the possibility of exporting part of the surplus wind power to Germany's neighbours (including France). The negative impact of RES on electricity spot market prices and their volatility are thus made less pronounced by interconnections.
Therefore, the rapid expansion in renewable energy in Germany has not occurred without less positive outcomes. While Germany's plan to shift to renewable energy enjoys overwhelming

public support, there is also growing concern about its increasing costs especially for German households. Therefore, the affordability of electricity is an important issue for the policymakers agenda in Germany. The Renewable Energy Act (EEG) needs urgent reform to address overcosts due to FIT support scheme.

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