Germany's Nuclear Power Plant Closures and the Integration of Electricity Markets in Europe

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ABSTRACT

This paper examines the potential implications of national policies that lead to a sudden increase of wind power in the electricity mix for interconnected European electricity markets. More specifically, it examines market integration before and after the closures of eight nuclear power plants that occurred within a period of a few months in Germany during 2011. The short- and- long run interrelationships of daily electricity spot prices, from November 2009 to October 2012, in: APX-ENDEX, BELPEX, EPEX-DE, EPEX-FR, NORDPOOL, OMEL and SWISSIX; and wind power in the German system are analysed. Two MGARCH (Multivariate Generalized Autoregressive Conditional Heteroscedasticity) models with dynamic correlations are used to assess spot market behaviour in the short run, and a fractional cointegration analysis is conducted to investigate changes in the long-run behaviour of electricity spot prices. Results show: positive time-varying correlations between spot prices in markets with substantial shared interconnector capacity; a negative association between wind power penetration in Germany and electricity spot prices in the German and neighbouring markets; and, for most markets, a decreasing speed in mean reversion.

Keywords: electricity market integration, energy transition, fractional integration, time-varying correlations, volatility transmission

1. **Introduction**

Common goals in European energy policy are security of supply, affordability and climate change. An integrated electricity market is seen as a means to address these objectives. Nonetheless, national policies that affect wholesale prices in one electricity market can impact the process of integration. The present study investigates short- and- long run associations of electricity day-ahead prices and wind power penetration in German market, which is the largest and most liquid in Europe, with other European markets, by comparing the periods of one year before and after the closures of eight nuclear plants that followed the 13th *Gesetz zur Änderung des Atomgesetz* (Nuclear Phase-Out Act).

A consensus on European energy policy could promote cleaner energy mixes, optimise complementarities, lead to dynamic pricing and align grid investment strategies (Boeckers et al., 2013; Hooper and Medvedev, 2009). Yet, in 2011, a unilateral course was taken in Germany that potentially altered wholesale electricity prices beyond its borders. As hinted by Germany's Environment Minister a year after, unintended consequences were possible: 'It was not possible to discuss the consequences of such a decision with Germany's neighbours. Now is the time for that.' (Peter Altmaier, European Energy Review, 2012). Indeed, Germany is Europe's largest economy and is committed to reduce emissions between 80 to 95% below the level in 1990 by 2050, of which 21% has since been achieved (Committee on Climate Change, 2013). Its energy transition, *Energiewende*, has led to considerable growth in intermittent renewable energy sources (RES-E), and wind power capacity increased from 183MWh in 1992 to 31.308MWh in 2012, so that Germany had a third of the installed EU wind power capacity in 2012 (EWEA, 2012). Consequently, with the closure of eight nuclear plants in a short period, the German electricity mix changed significantly; the share of other technologies increased, most noticeably wind power, as will be highlighted in the next section.

The possibility of unintended consequences from isolated national energy policies that alter the electricity mix in interconnected electricity markets motivates this study. In the next section, the contextual background is described in greater detail. Section three reviews the literature on the implications of growing RES-E for electricity price behaviour, price volatility transmission and market integration. Section four sets the hypotheses to be tested. Section four describes the methodology and data. The results are reported in section five. Section six discusses the main findings, and section seven concludes the paper.

2. Germany’s electricity mix and trade flows following the Nuclear Phase Out

The decommissioning of eight nuclear power plants in Germany as a response to the events in Fukushima led to a 23% reduction in gross electricity generation capacity from nuclear (Öko Institut, 2013). Given an increase in the share of intermittent RES-E in the German electric system, secure capacity, which is the capacity that is available 99% of the time, decreased. Figure 1 illustrates the secured and available electricity generation capacities in Germany in January 2011 in GW, before the closures. At that time, of the total installed RES-E capacity (51.5GW), only 9% (4.8GW) was classified as secure. In the case of conventional plants, availability is subject to outages, revision and failures. Consequently, from the total installed available capacity of 160.2GW only 58% (93.1GW) was secure. Given a peak-load demand in Germany of 80.6GW in 2011, the reserve margin before the closures of the eight nuclear power stations was equal to 12.5GW (BDEW, 2011). This value exceeded the adequate reserve margin of 7GW, which is suggested by ENTSO-E. However, after the closures of eight nuclear plants in 2011, the reserve margin decreased to 6.2GW, which is below the security threshold (ENTSO-E, 2011).

-Figure 1 here-

Until August 2011, Germany had been a net exporter of electricity with stable commercial flows. Exports were generally to the Benelux countries, which have a high proportion of variable peak electricity sources, such as coal- and gas-fired plants. Germany imported electricity from France, mostly produced by nuclear plants, and the Czech Republic, which in 2010 had high proportions of fossil fuel-based (54.8% or 47.1TWh) and nuclear (32.6% or 28TWh) generation (European Commission, 2012). Electricity flows with Denmark, Sweden and Poland depended on the availability of wind power (BDEW, 2011).

After August 2011, with lower reserve margins, trade patterns changed. In the six weeks that followed the announcement and the reduction of total net capacity by 6.305MW, Germany became a net-importer of electricity (BDEW, 2011). However, the decommissioning of the nuclear power capacities in Germany coincided with the seasonal shift in its electricity trade with neighbouring markets: electricity was traditionally exported in the winter and imported during the summer, when there is greater availability of hydro and lower demand for nuclear in neighbouring markets (Öko Institut, 2013). Nevertheless, when considering a longer period (one year before and one year after 6th of August 2011), Germany remained a net exporter. Overall imports rose by 894GWh, while the increase in net exports was 5103GWh (ENTSO-E, 2014). Trade flows actually increased, and the expectation of greater imports was not confirmed. The reduction in electricity generation from nuclear was offset in the annual balance by two thirds, through increased generation from RES-E (+20.2TWh) (Öko Institut, 2013). In addition, when comparing statistics of newly commissioned wind turbines in the years 2009/2010 to 2011/2012, a 30% increase in capacity is observed (BWE, 2014). In short, favourable weather conditions and strong investments in wind farms further increased the share of electricity generated by RES-E in Germany.

3. RES-E and Electricity Market Integration in Europe

Several studies have addressed growing RES-E integration (e.g. Gross et al., 2006; Henriot and Glachant, 2013; Holttinen et al., 2009; Smith et al., 2007), but they mainly highlighted the need for secure reserve capacity due to the intermittent nature of wind power. Some authors (e.g., Bode and Groscurth, 2006; Gil et al., 2012; Jacobsen and Zvingilaite, 2010; Neubarth et al., 2006; Nicolosi, 2010; Ray et al., 2010; Saenz de Miera et al., 2008; Sensfuß et al., 2008), however, observed that increasing wind power penetration is negatively correlated with electricity spot prices. In high-wind scenarios, given the merit order of dispatch, more expensive generators have very low load factors (Claudius et al., 2014; Forrest and MacGill; 2013, Sensfuß et al., 2008; Woo et al., 2011, Würzburg et al., 2013), and therefore electricity wholesale prices are expected to drop. However, a side-effect of intermittent RES-E on wholesale markets is an increase in day-ahead and intra-day price volatility, since the merit-order curve, which in most cases should determine price, can change significantly between high- and- low wind scenarios. Price risk, to which generators and suppliers are exposed in liberalised markets, increases due to the limited storability of electricity, which implies instantaneous balance of supply and demand, and the high variability of wind power (Paraschiv et al., 2014). Not surprisingly, Traber and Kemfert (2011), when investigating the German market, found that the incentive to invest decreased for all technologies with the development of wind generation. Consequently, with high wind power penetration levels, concerns over security of supply call for incentives in flexible generation. However, as Spiecker and Weber (2013) argued, the need for more flexible generation capacity can be reduced by grid extensions and market coupling. Still, studies (e.g. Neuhoff et al. 2013; Oggioni et al. 2014) that investigated wind power integration policies suggest that priority dispatch, as in Germany, can hinder market integration. As a whole, the literature suggests that increasing intermittent RES-E penetration can lead to higher spot price volatility at least in the local market, and this expectation should be considered when investigating integrated markets.

To date, multi-market empirical studies appear to have neglected the possible effects of RES-E generated electricity in interconnected regions. Considering the Australian electricity spot markets, Worthington et al. (2005) showed no price spillover across markets, but significant volatility transmission in nearly all markets. Higgs (2009) observed that the less direct the interconnection between markets, the lower the volatility spillover between them. By contrast, when Zareipour et al. (2007) compared different volatility indices in four interconnected North American electricity markets (Ontario, New England, New York, and PJM), they observed that volatility increased in the direction of well-connected, less mature or smaller markets.

Considering European electricity markets, which are the subject of the present study, Solibakke (2008) investigated volatility transmission between the daily German electricity price index Phelix and spot prices from Nord Pool between 2000 and 2006, and found strong cross-market correlations that lasted for up to three days. Similarly, Le Pen and Sévi (2010) observed returns and volatility spillover effects in the German, Dutch and British forward electricity markets. Bunn and Gianfreda (2010), however, analysed volatility interactions between five European spot and forward markets (British, Dutch, French, German, Spanish), and concluded that volatility transmission decreased with proximity to the maturity of the contracts. Overall these studies highlight that price volatility can spread across interconnected electricity markets. Consequently, long-run electricity price dynamics may also become more volatile and impact the convergence to the single market, which following EU directives should be completed by 2015.

A growing body of literature has been focusing on evaluating electricity market convergence in Europe. Most studies adopt the Law of One Price (Fetter, 1924) as the core theoretical foundation for common long-run dynamics. The set of markets, periods examined and the status-quo of market integration that is inferred vary significantly between studies. Some authors concluded that electricity wholesale prices are converging (e.g. Armstrong and Galli, 2005; Bunn and Gianfreda, 2010; Kalantzis and Milonas, 2010; Robinson 2008), but that convergence may be stronger in periods of peak demand (support Armstrong and Galli's, 2005) or in directly well-connected markets (Bunn and Gianfreda, 2010). By contrast, recent assessments (e.g. de Menezes and Houllier, 2014; Pellini, 2012, Pinho and Madaleno, 2011) suggest less convergence in electricity spot prices, and at least two of these studies concluded that market integration in Europe remains in its infancy. Nonetheless, of particular relevance to the present study, Bollino et al.'s (2013) analysis of price convergence in four markets (Austria, Germany, France and Italy) between 2004 and 2010 showed that German electricity prices acted as a signal for neighbouring markets.

Since it can be argued that in the liberalised EU markets, common long-run price dynamics would reflect the cost of generation in the region, several studies have assessed the link between energy sources and electricity prices (e.g. Asche et al. (2006), Bollino et al. (2013), Bosco et al. (2010), Bosco (2006), Emery and Liu (2002) Gjolberg (2001), Kalantzis and Milonas (2010), Mjelde and Besseler (2009), Mohammadi (2009), Roques et al. (2008), Sensfuβ et al. (2008), Sereletis and Herbert (1999)). In this line of research, Aatola et al. (2013) were the first to consider RES-E policies in their assessment of electricity market convergence. Using daily electricity and carbon forward price data from 2003 to 2011, the authors concluded that electricity market integration in Europe was increasing over time, and that carbon prices might have had a positive but uneven effect on integration. Subsequently, Castagneto-Gissey's (2014) analysis of electricity and carbon prices in the year-ahead energy markets during ETS Phase II highlighted that electricity prices in the EU can be driven by coal prices, but also that generators may excessively charge for the cost of carbon. It showed that German and Nord Pool electricity prices increased 35% above the competitive threshold given a unit increase in costs. Although electricity prices could have been driven by the generators with greater emissions, generators might have also pushed for higher electricity prices. The level of competition is therefore an important factor in the determination of wholesale electricity prices and may also moderate the associations between coal and electricity prices in European markets. Moreover, Brunner (2014) noted that the relationship between electricity demand and spot prices in Germany is likely to be moderated by the supply of RES-E.

To date, the different streams of literature reviewed have little in common. Studies on the integration of RES-E on price dynamics have generally focused on one specific market. Studies that assessed short-run interrelationships or price convergence in the long run have neglected the potential effects of RES-E penetration. The present study links these streams of literature, by focusing on how wind power penetration in the German market may have impacted spot price behaviour in Germany and connected markets. In doing so, it assesses the implications for the development of the Pan-European electricity market. The next section considers potential implications of the surge in wind power generation in the German electricity mix, which followed the start of the implementation of the German Nuclear-Phase Out, and sets the hypotheses to be tested in this study.

4. Implications of increasing shares of RES-E in Germany for EU electricity markets

The drop in base-load capacity and the increasing share of RES-E in the German system, described above, may have led to greater price fluctuations. Even if reserve margins were sufficient, offsetting the decommissioned nuclear power generation by intermittent RES-E might have resulted in more volatile electricity output and spot prices. In periods of low levels of wind power generation, there would be a shift towards the steeper slope in the German merit-order curve and therefore, small changes in demand or supply could lead to price spikes. Indeed, as reported in the preceding section, a higher proportion of wind power in the electricity mix has been linked to lower average prices and increases in price volatility within one market. Moreover, in interconnected markets, a sudden surge in the share of wind-generated electricity in a market can decrease electricity prices not only locally but also in connected markets, because rational players recognise profitable arbitrage opportunities. By buying electricity in the cheaper market, price shocks can then be transmitted between neighbouring markets, subject to available transmission capacity. Analogously, a sudden decrease in the share of wind-generated electricity may increase electricity imports in the German market, which is not only central but also the most liquid in the region. Consequently, it is hypothesised:

Hypothesis1a: *Following Germany's nuclear power station closures in 2011, stronger associations between wind power penetration and spot price movements are observed.*

In theory, in integrated and efficient electricity markets without network congestions, prices and, as result their volatility, should be identical. As described above, interconnection and geographical proximity have been found to be associated with the convergence of electricity spot prices in Europe. Given the interconnection between the German and neighbouring markets, it is therefore hypothesised:

Hypothesis 1b: *After Germany's nuclear power station closures in 2011, price volatility transmission across EU electricity markets increased.*

4.1 Implications for electricity spot price dynamics

The speed of mean reversion is useful for regulators as an indicator of market resilience, because it quantifies how quickly the generation side can react to unexpected events by ramping generation capacity up or down. With increasing electricity market integration, prices should converge and the speed with which prices revert to their mean should increase as an integrated EU electricity system relies on a larger generation portfolio. Yet, shifts in energy policies that affect the electricity mix impact price differentials (competitiveness) locally and in interconnected markets. With a merit-order curve that varies with the amount of wind-generation, electricity spot prices are more volatile, and consequently the speed with which they may converge to a mean is likely to be affected. Persistence of price spikes (slower mean reversion) would signal reductions in system flexibility, as unexpected changes in demand or supply levels are less easily overcome. It is therefore hypothesised:

Hypothesis 2a: *After Germany's nuclear power station closures in 2011, the speed with which electricity spot prices revert to the mean has decreased.*

4.1.1 Co-integration of EU electricity markets

The German electricity market is the largest in Europe. As highlighted above, greater spot price volatility in the larger market can impact price differentials with interconnected markets, especially if markets are unable to quickly respond to price signals. Hence:

Hypothesis 2b: *After Germany's nuclear power station closures, less integration between EU electricity spot markets is observed.*

5. Methods

The dataset is divided into two subsamples to test the hypotheses, with 6 August 2011 being the date by which eight nuclear plants had been closed permanently following the timeline legislated on 30 June 2011 (BMU, 2011). For assessment of changes in associations (Hypotheses 1a and 1b) and in mean reversion (Hypothesis 2a), the Chow (1960) breakpoint test is employed. This test entails a one-sided *t*-test, whose alternative hypothesis is defined according to the hypothesised direction of change.

5.1 Assessing changes in correlation and volatility transmission

In order to investigate changes in the association between wind penetration levels and spot prices and volatility transmission between spot markets, as implied by hypotheses 1a and 1b, two alternatives of Multivariate GARCH models are estimated on two sets of variables: (1) log-returns of spot prices and actual wind power penetration levels, (2) log-returns of spot prices and planned (expected) wind power penetration levels. Given the time-varying assumptions, dynamic conditional correlation models are used, the mean of estimated correlations in each period (pre and post 6 August 2011) is computed and changes are then evaluated via a breakpoint test.

5.1.1 Dynamic Conditional Correlation Models

Tse and Tsui's (2002) proposal of a dynamic conditional correlation model is considered, which hereafter is referred to as TTDCC. According to this model, the dynamic conditional covariance matrix at time *t* is such as follows:

$$H_t = D_t \Gamma_t D_t = \rho_{ijt}(h_{iit}\, h_{jjt})^{\frac{1}{2}}, \tag{1}$$

where

$$D_t = diag(h_{11t}^{\frac{1}{2}} \dots h_{KKt}^{\frac{1}{2}}) \tag{2}$$

h_{iit} is the conditional variance of the univariate GARCH model for variable *I,* as follows:

$$h_{iit} = \beta_0 + \beta_1 \varepsilon_{it-1}^2 + \beta_2 h_{iit-1}\,, 1 \le i \le j \le K, t = 1, \dots, N; \tag{3}$$

$\beta_0, \beta_1, \beta_2$ are parameters to be estimated, *K* is the number of variables in the model and *N* is the number of observations in the estimation period. Γ_t is the *K*x*K* symmetric time-varying positive definite conditional correlation matrix whose diagonal elements are $\rho_{ii} = 1\,, \forall i$, and is defined as follows:

$$\Gamma_t = (1 - \theta_1 - \theta_2)\Psi + \theta_2\Psi_{t-1} + \theta_1\Gamma_{t-1}, \tag{4}$$

θ_1 and θ_2 are non-negative constants, such that $\theta_1 + \theta_2 < 1$. Ψ is a constant positive definite parameter matrix of ones, and Ψ_{t-1} is a function of the lagged standardised residuals ξ_{it}, such that:

$$\Psi_{t-1,ji} = \frac{\sum_{m=1}^{M} \xi_{i,t-m}\xi_{j,t-m}}{\sqrt{(\sum_{m=1}^{M} \xi_{i,t-m}^2)(\sum_{m=1}^{M} \xi_{j,t-m}^2)}} \tag{5}$$

and

$$\xi_{it} = e_{it}/h_{iit}^{\frac{1}{2}} \tag{6}$$

In addition, Engle's (2002) alternative dynamic conditional correlation matrix is estimated, i.e.:

$$\Gamma_t = diag\left(q_{11t}^{-\frac{1}{2}} \dots q_{KKt}^{-\frac{1}{2}}\right)\left((1 - \theta_1 - \theta_2)\bar{Q} + \theta_1\xi_{t-1}\xi_{t-1}' + \theta_2 Q_{t-1}\right)diag\left(q_{11t}^{-\frac{1}{2}} \dots q_{KKt}^{-\frac{1}{2}}\right) \tag{7}$$

where $\bar{Q}$ is the KxK unconditional correlation matrix of ξ_t, and θ_1 and θ_2 are non-negative parameters satisfying $\theta_1 + \theta_2 < 1$ (Higgs, 2009). Hereafter, this formulation is referred to as the EDCC model.

5.2. Assessing price dynamics: Fractional Integration

Long-run associations of electricity spot prices can be obscured because of the presence of large spikes in the data. Consequently, the time series needs to be smoothed before assessing their long-run dynamics. The study conducted by Trück et al. (2007) is referred to for the outlier treatment that is adopted. Outliers are defined as values that exceed or fall below the rolling window mean average by three standard deviations over a one-month period. The proportions of outliers varied with the time series, the threshold and length of the moving average were decided so that the number of observations to be replaced would not exceed five per cent of the sample. Four iterations were conducted, according to which the Nordic and German spot markets had the lowest proportion of outliers (1.1%) while the French spot market had the highest (4.5%). The identified outliers were replaced by a mean average of lags and leads within one month.

In order to assess changes in mean reversion (Hypothesis 2a), the concept of fractional integration (Robinson, 1994) is utilised, i.e.: A process X_t is said to be integrated of order *d*, *I(d),* if its fractional difference, $(1-L)^d X_t$, is a stationary or mean- reverting *I(0)* process. The fractional difference operator is the following:

$$(1-L)^d = \sum_{k=0}^{\infty} \frac{\Gamma(k-d)L^k}{\Gamma(-d)\Gamma(k+1)}. \qquad (8)$$

In cases when $-\frac{1}{2}$<*d*< $\frac{1}{2}$, the process is stationary and invertible, when *d*≥ $\frac{1}{2}$ the process is non-stationary. However, the time series process is mean reverting when $\frac{1}{2}$ ≤*d*<1.

Key to the assessment of the nature of the process is therefore the estimate of the order of integration parameter *d*, for which a semi parametric two-step feasible exact local whittle (FELW) estimator (Shimotsu, 2006) will be used. This estimator is robust to misspecification of the short-run dynamics and can handle stationary (*d*< ½) and non-stationary (*d*≥ ½) processes (Okimoto and Shimotsu, 2010). Moreover, it is unlikely to be affected by conditional heteroscedasticity (Robinson and Henry, 1998; Shao and Wu, 2007), which is a common characteristic of electricity price series. Following, Lopes and Mendes (2006) in the analysis that follows the bandwidth *m* for estimating the FELW is set to 0.75.

First, the time-varying estimates of order of integration are plotted using a rolling window of 200 observations. These estimates are smoothed with Hodrick-Prescott's (1997) filter with a smoothing parameter equal to 250. Secondly, one hundred perturbed series are obtained by adding a random noise (*N(0,1))* to the original time series. Their order of integration, *d,* is then estimated using the FEWL based on 260 observations, corresponding to a period of one year, both before (d_before) and after (d_after) the closure of the eighth nuclear plant. Mean estimates in each period (before and after) are then used to test the hypotheses with standard *t*-tests.

5.3 Assessing market integration: a Fractional Cointegration Analysis

To test for electricity spot price convergence (Hypothesis 2b), the *fractional cointegration* framework (Granger, 1986; Engle and Granger, 1986; Johansen, 1988) is adopted. The aim is to establish co-movement of fractionally integrated time series, i.e.: *Two time series* x_t *and* y_t*, integrated of order d, (I(d)) are said to be fractionally cointegrated of order (d, b) if the error correction term given by*

$$z_t = y_t - \beta * x_t \tag{9}$$

is fractionally integrated of order b, where $0 < b \leq d$ (Banerjee and Urga, 2005). First, a *t*-test is carried out to assess if x_t and $y_t$are integrated of the same order. When the order of integration of the two time series, x_t and y_t, are not significantly different, the error correction term (z_t) is computed via an ordinary least square regression of x_t on y_t. Subsequently, the order of integration of the error correction term, z_t, is estimated using the FELW estimator, and tested: if this value is significantly smaller than the common order of integration d of the time series x_t and y_t, then cointegration is established.

5.4 Data

The dataset consists of electricity spot prices from eight European electricity spot markets: APX-NL (Netherlands), APX-UK (GB), BELPEX (Belgium), EPEX-DE (Germany), EPEX-FR (France), NORDPOOL (Norway, Denmark, Sweden, Finland, plus Estonia (from 2010) and Lithuania (from 2012)), OMEL (Portugal and Spain) and SWISSIX (Switzerland) covering the period from 2 November 2009 to 9 October 2012. The analysis focuses on week-daily (Monday to Friday) mean of prices (base load), thus comprising 767 observations for each market.

Hourly forecasts and actual electricity output generated by wind were obtained from the Transparency in Energy Markets EEX database (www.transparency.eex.com). These time series are also converted to a week-daily frequency (Monday-Friday), and then divided by the daily volume traded on the German spot market, thus providing the share of wind power that is traded on the day, which will be referred to as actual 'Wind Power' and forecasted 'Planned Wind Power' penetration time series. Table 1 summarises the electricity spot prices of the different markets in €/MWh as well as the two wind power penetration time series. The data distributions reject normality: the Jarque-Bera statistics exceed their critical values, and all markets, except OMEL, exhibit positive skewness; high kurtosis (extreme values) is also observed, especially in EPEX-FR.

Table 1 here

Table 2 summarises the smoothed (outlier-treated) time series of spot prices, 'planned wind' and 'actual wind' penetration in the period from 6 August 2010 to 6 August 2012, which are used to test hypotheses 2a and 2b. Average electricity prices, in the different markets, range from 45.10€/MWh (Nord Pool) to 57.47€/MWh (SWISSIX) as reported in column 3. The last column contains the estimate for the order of integration d, based on which the speed of mean reversion of each time series can be assessed: the lower this value, the quicker spot prices revert to their mean. Accordingly, APX-UK (d= 0.489) had the fastest speed of mean reversion in the period. By contrast, the highest values of d are observed for EPEX-FR and Nord Pool (0.906 and 0.862, respectively). The EPEX-FR, in particular, is very close to one, suggesting that the market would have reacted very slowly to unexpected supply or demand shocks.

Table 2 here

6. Results

6.1 Time-varying correlations with German wind power penetration and changes in price dynamics

Following model selection criteria, the best and most parsimonious fits to the univariate time series were achieved by ARMA(1,1)-GARCH(1,1) models with *t*-distributed errors. This specification confirms the changing volatility (heteroscedasticity) and the spiky nature of the time series (some high kurtosis, as shown in Table 1). Accordingly, wind penetration levels, spot prices, and their volatilities are influenced by the previous values and shocks. Plots of the estimated correlations in the period confirmed that all associations are time-varying.

Tables 3 and 4 show the average correlations in each period using the TTDCC model, values before 6 August 2011 are shown in the top triangle of each table, while those after this date are shown in the bottom triangle. Overall, there are more significant associations after 6 August 2011. The 31 significant (1% level) correlations in Table 3 range from 0.17 (for APX-NL and OMEL, as well as OMEL and SWISSIX) to 0.97 (BELPEX and EPEX-FR). In Table 4, where the data includes 'Planned Wind Power' rather than actual wind power, 30 correlations are significant at 1% level and are within the same range - from 0.17 (for APX-NL and OMEL) to 0.97 (BELPEX and EPEX-FR). Given the break point tests (one tailed *t*-tests), seven (Table 3) and eight (Table 4) of the estimated correlations have increased, when comparing the averages before 6 August 2011 (top triangle) with the averages after 6 August 2011 (bottom triangle), and they are highlighted in bold.[2]

[2] Plots and one-tailed *t*-test results can be obtained from the authors upon request.

Average correlation coefficients after 6 August 2011 for 'Wind Power' and 'Planned Wind Power' are shown in the last row and column (9) in both tables. The correlations between wind power penetration levels and spot price returns are generally negative: the number of significant associations with 'Wind Power' (Table 3) increased from two (column 9) to seven (last row) when one compares the period before to after 6 August 2011. The two models are consistent with respect to those associations that increased significantly (5% significance level): only the strength of associations between German wind power levels and spot prices in BELPEX and EPEX-FR increased in the period. As expected, the correlation is negative, thus the greater the level of German wind power, the lower the spot prices in these markets. The time-varying volatility of German wind power also implies that when correlations are significant, as shown in the last rows and columns of Tables 3 and 4, there is volatility transmission between German wind power and spot prices, and this is the case in the German and all other markets, except OMEL.

Table 3 here

Table 4 here

The correlations between electricity spot price returns and volatilities are on average positive, as shown in Tables 3 and 4. In general, associations are stronger the closer and more connected the markets are. Before 6 August 2011, the average correlations ranged from 0.42 (BELPEX and SWISSIX) to 0.84 (BELPEX and EPEX-FR) in the model that included 'Wind Power' (Table 3), and from 0.18 (APX-UK and SWISSIX) to 0.99 (BELPEX and EPEX-FR) in the model with 'Planned Wind Power' (Table 4). When compared to other markets, spot prices in NORDPOOL and OMEL have fewer and weaker correlations. In the top triangle of Table 3, it can be seen that before 6 August 2011, spot prices in OMEL were independent of spot prices in the other markets. After 6 August 2011, as shown in the lower triangle of Table

3, although significant, the correlations are low (0.17 to 0.26). These results are likely to reflect OMEL's limited physical connection with the other markets. For example, with neighbouring France, interconnection represented a mere 3% of Spain's electricity generation (Bilbao et al., 2011).

NORDPOOL, however, is better connected, but is also more resilient to shocks because it has a more evenly distributed electricity mix and a higher share of flexible generation (Deidersen and Trück, 2002). With pump-storage electricity acting as a buffer, prices would be expected to vary less than in neighbouring markets. However, this has not been observed in the period, as illustrated by the standard deviations reported in Tables 1 and 2. The Nordic Market Report 2013 (Nordic Energy Regulators, 2013) described that increases in water levels in the period led to increases in hydro generated electricity and decreases in thermal generation and prices. Consequently, there were greater variations in prices that also impacted their correlation with prices in other markets.

Following the same format of the previous tables, average correlations obtained with the EDCC models are displayed in Tables 5 and 6, and generally confirm the results of the previous models. For example, in EPEX-DE, the correlation between spot prices and 'Wind Power' increased from an average of -0.42 to -0.58 (Table 5), thus supporting Hypothesis 1a and indicating that a greater share of the volatility of wind power would have been transmitted to spot prices after 6 August 2011. The average association between spot prices in EPEX-FR and German wind power has more than doubled: from an average of -0.18, before 6 August, to -0.43 (based on actual) and -0.42 (based on planned) after 6 August. Likewise, with BELPEX, average association increased from -0.18 to -0.41 and -0.39.

Table 5 here

Table 6 here

The stronger association with 'Planned Wind Power' in comparison to the actual level of wind power that is observed in both models is not surprising. Forecasts for the day-ahead are made publicly available by the transmission systems operators, and therefore wind power expectations can be incorporated into prices. Overall, there is limited support for increases in the associations with German wind power after the closures of the eight nuclear plants, as stated in Hypothesis 1a, since only two associations between wind power penetration and electricity spot prices became significantly stronger after 6 August 2011. Yet, most associations between German wind power and spot prices are significant at 1% level, consequently the data show volatility transmission from German wind power to spot prices, not just locally, but also in all markets except for OMEL.

Given greater volatility in electricity spot markets, an increase in the volume traded in forward markets would be expected. Indeed, month-ahead German base-load trade data obtained from Tullett Prebon Information for the period from August 2010 to August 2012 show increases in traded volumes and number of trades after the plant closures. Comparing one year before with one year after 6 August 2011, the number of trades in German base load grew by more than 35%, from 3484 to 5375; and traded volumes increased by 28%, from 45.6TWh to 63.2TWh. When the nuclear plant closures were announced, one-month-ahead prices of base load moved from their mean average of 50.3 €MWh to 62 €/MWh. However, in a few month prices converged towards 40 €/MWh. Furthermore, despite an increased demand for base-load contracts, a decrease in the average price per MWh paid from an average of 52.3 €/MWh to 48.53 €/MWh is observed when comparing one year before with one year after 6 August 2011. These data support the inference that the capacity reduction in the German electrical system was offset by rising shares of wind power.

Since most average correlations between spot prices are significant, there is evidence of volatility transmission of spot prices across EU electricity markets. As for specific associations with German spot prices, few associations have actually increased in the period analysed. Although increases in average correlation vary with the model that was estimated, they relate to spot markets that share borders with Germany, namely: EPEX-FR, BELPEX, SWISSIX, and APX-NL. Hence, there is some support for Hypothesis 1b, which states that spot price volatility transmission would have increased after the closure of the German nuclear plants. Yet, results seem to suggest that if there were impacts, these were limited to some neighbouring markets.

6.1 Changes in mean reversion in the spot market

Figure 2 depicts the time-varying estimates of the order of integration (d) of electricity spot prices between January 2010 and October 2012. Considering NORDPOOL spot prices, increasing values of the parameter d can be observed briefly after March 2011, and thus there is a decrease in the speed of mean reversion. By contrast, an abrupt drop in the order of integration of British spot prices can be noticed soon after April 2011, thus indicating a faster speed of mean reversion. In summary, there are signs of divergence in electricity price dynamics in the second quarter of 2011, which will be further investigated.

Figure 2 here

The sample means of the estimated ds of the perturbed spot price series, their confidence intervals and the results of the t-tests are summarised in Table 7, and broadly confirm the observations that were made based on Figure 2. Confidence intervals for the means of ds that are shown in the third column tend to overlap in the period before 6 of August, thus suggesting that differences in the speed of mean reversion were not significant in this period. After 6 August, however, some confidence intervals do not overlap: APX-UK has a lower interval when comparing to all markets bar OMEL; NORDPOOL and SWISSIX have higher intervals when compared to EPEX-DE, APX-UK, and OMEL. There are signs of divergence and decreases in mean reversion for most spot prices. According to one-sided *t*-tests, for which the statistics are shown in the last column of Table 7, the parameter *d* has increased for all spot prices, except in OMEL and APX-UK. For the former, there is no significant change in the parameter *d* and for APX-UK there is a decrease that may, however, be explained by the greater competitiveness in the period of flexible gas-generated electricity, due to low fuel costs (European Commission, 2011), rather than the association with other European markets. In all, Hypothesis 2a is supported, since the speed with which electricity spot prices revert to their mean decreased in all markets apart from those that are less connected to the German market.

Table 7 here

6.2 Changes in convergence of electricity spot prices

Given the above findings, the process of convergence to a common price is likely to have changed. Table 8 summarises t-tests that assess the Null hypothesis of a common order of integration for pairs of markets before (above diagonal) and after (below diagonal) 6 August 2011. These results broadly confirm the general observations based on the 95% confidence intervals in Table 7. Before 6 August 2011, twenty pairs did not reject the null of a common order of integration. By contrast, after 6 August 2011, the null hypothesis is rejected for most pairs (as shown below the diagonal in Table 8). None of the spot prices had a common order of integration with spot prices in APX-UK. This result further highlights the different in price dynamics between the British and the other EU spot markets in this study, which is likely to be due to the limited interconnection between them.

Table 9 considers all pairs of time series that have previously been found to have a common order of integration. Cointegration tests are summarised; significant differences at 5% level are indicated by asterisks, and show that before 6 August (top triangle), five market pairs were integrated. After this date (bottom triangle), nine pairs were integrated. Nonetheless, the cointegrated pairs differ: after 6 August 2011, no market was integrated with EPEX-DE, while before that date APX-NL and SWISSIX were. Overall, the hypothesis of less integration within EU electricity spot markets is rejected. There are indications of a decoupled German electricity market after the nuclear plant closures. In addition, the results in Table 9 also show increasing integration between BELPEX, APX-NL, NORDPOOL and EPEX-FR.

Table 8 here

Table 9 here

7. Discussion

The empirical findings show that wind power can no longer be neglected in studies of the integration of European electricity markets. Wind power penetration levels in Germany were found to be negatively associated with spot prices in Germany but also in other markets. In the long run, increasing levels of wind power can lead to lower wholesale prices. The drawback is that there is also evidence of volatility transmission. Given that positive short-run associations across EU electricity spot markets were also found and are stronger the closer and better connected the markets are, with the combination of increasing wind power generation and market integration, electricity spot prices are likely to become more volatile.

Participants in an integrated day-ahead market will need to trade off the additional price risk with the expectation of lower prices in high-wind scenarios. On the one hand, larger suppliers could make more use of future contracts, but in doing so they would miss opportunities of lower prices, their final price would then be more expensive to the consumers. High-wind scenarios could therefore benefit smaller suppliers, who could then more quickly pass on lower prices to the consumer. On the other hand, in high-wind scenarios, the more expensive flexible generators become less attractive investments (Paraschiv et al., 2014; Traber and

Kemfert, 2011), they would have to rely on capacity payments and make more use of take or pay contracts. In all, there are greater incentives for hedging and more flexible contracts, options (e.g. swings, recalls and nominations), and greater use of contracts for differences between generators and suppliers.

Cross-border electricity trading is dependent on price differentials. A main finding of this study, which is in line with recent studies (e.g. Castagneto-Gissey et al., 2014), is that the dynamics of electricity spot prices in European markets are time-varying. Consequently, price differentials in the short run are time-varying, thus making the task of forecasting interconnector flows more difficult for transmission operators. This is a challenge, as historical data on price differentials become less reliable, but is also an opportunity for greater share of information in the European electricity supply chain. Reliable estimates of trade flows are likely to be important for future capacity assessments in Europe, since the decommissioning of old plants in the UK and the phasing-out of nuclear plants in Belgium, Switzerland and Germany have led to concerns about the nations' abilities to secure supply in the near future.

The results also show that spot prices in OMEL and APX-UK were less affected by developments in central European markets. This finding reinforces the role of interconnection in electricity markets, as highlighted in the review of the literature and observed in the particular case of OMEL. It is noteworthy that Britain has interconnectors with France and the Netherlands, where price differentials (as shown in Tables 1 and 2) would have favoured imports to Britain, these interconnections seem to have been used in congestion management during the period analysed and therefore would not have a significant share in the day-ahead market. Britain is also interconnected with Ireland, with price differentials mostly favouring exports. Yet, as McInerney and Bunn (2013) described in their analysis of the Moyle interconnector, transmission capacity rights have been undervalued and some flows were found to be opposite to the efficient direction. The authors' explanations for inefficiencies include intermittent wind power and the strategic behaviour of dominant firms. As a whole, undersubscription of transmission rights and other uncertainties related to interconnection have meant that the transmission operator and the recent UK capacity market auctions considered interconnectors at float for transmission planning. However, the situation is changing, because interconnectors are becoming more responsive since February 2014 as a consequence of market coupling. Moreover, with the planned increases in interconnection and future targets for market coupling, interconnectors are likely to play a greater role in the day-ahead market. Consequently, significant shifts are expected in the relatively low and stable correlations that were estimated in this study.

In addition, the higher average short-run correlations (greater than 0.70), which were observed between spot prices in BELPEX and SWISSIX with their larger neighbouring markets, appear to support previous observations that in well-connected electricity markets price volatility transmissions are in the direction of the smaller markets (e.g. Zareipour et al., 2007). This may be a cause for concern, and further investigation is desired covering a wider period, and in the case of BELPEX, a longer range study of market volatility pre and post market coupling would enable a clearer assessment.

Faced with a more volatile electricity supply, smart technology has been advocated (e.g. Strbac, 2008) and targets have been set at European and national levels (e.g. DECC, 2013). In this context, virtual power plants that aggregate decentralised sources of generation or pool together large consumers that can temporarily reduce their electricity consumption have been presented as efficient solutions or means to reduce dependency in interconnection to secure supply. They can decrease price volatility by flattening demand peaks. In doing so, investment signals are also reduced, but the trade-off is that in low-wind scenarios, they can contribute to capacity. So far, their volumes are relatively small, but as 2020 approaches, these potentially local changes in demand and supply will be of relevance to the analysis of the short-run covariance of spot prices in connected markets.

The long-run dynamics of the eight spot markets, which were analysed, imply that during the year after the closure of Germany's nuclear plants, supply or demand shocks were less easily overcome. The speed with which prices reverted to their mean decreased for all markets, except for OMEL and APX-UK, which are not directly connected to the German market. This observed change in mean reversion suggested that market integration might have been affected by the change in Germany's electricity mix. Indeed, the German market was no longer integrated with the two markets that it had been in the year before. This finding could mean that the largest and most liquid market would no longer be acting as a signal to neighbouring markets, as previously described in the literature (e.g. Bollino et al., 2013). Nevertheless, several other market pairs were integrated, and thus the long-run market convergence may be more resilient to changes in a central market than might have been expected. Furthermore, considering the markets that became more integrated in the period analysed, there is some evidence that market coupling has played its expected role in the path towards a single market for electricity.

In an integrated price-coupled market, power flows between two regions would be based on bids and offers in both power exchanges to establish the market clearing prices and the owners of interconnectors would be remunerated according to the total flow in the period. Yet, as McInerney and Bunn (2013) warned, given the challenge of integrating market systems and infrastructure, explicit auctions for interconnector capacity will remain for some time in Europe. Consequently, as Gebhardt and Hoeffler (2013) observed when analysing different interconnectors with Germany, there can be significant variations in relationship between interconnector prices and spot prices. Power flows in interconnectors may not support expectations that are based on price differentials, thus the authors concluded that informed players were not engaging in cross-border trading. Gebhardt and Hoeffler (2013) therefore conjectured that where markets are concentrated, big players may collude and forego the use of an interconnector. By not engaging in cross-border trading, they maintain their local dominant status. It is therefore possible that lack of competition could partially explain some of the low correlations that were observed in the present study. Regulators in connected markets should closely coordinate the monitoring of anti-competitive behaviour, since, as highlighted by Castagneto-Gissey (2014), the level of competition also impacts electricity prices in European markets. Nonetheless, the expectation remains that with market coupling price correlations increase, as observed in the results. Given that wind power penetration levels were found to be important in assessments of market integration, a limitation of the present study is that wind power levels in the other markets and different types of RES/E were not considered due to lack of access to reliable data. The analysis focused on daily average spot prices from Monday to Friday, which simplified the econometric modelling by eliminating seasonal effects. A drawback of this simplification is that inferences cannot be made concerning intra-day variations, especially peak periods. The statistical tests enable the identification of changes in patterns, some of which were in line with the hypotheses, correlations and differences were observed but causality is not implied. The findings are robust insofar as it is possible to conclude that the short-run variance and covariance as well as the long-run dynamics of European spot prices are changing, and these associations may react to special events.

8. Conclusion and Policy Implications

Our findings suggest that the amount of interconnection and RES-E in European electricity markets can no longer be neglected by policy makers when they are legislating and planning for the long term. As highlighted, if prices are positively correlated, the combined price volatility is higher than the sum of individual volatilities, thus market players can be exposed to greater price risk from interconnection. Although volatility is desired because it stimulates trading and encourage the participation of financial institutions and other players in electricity markets, thus making markets more liquid and competitive, too much volatility can hinder investments in infrastructure and capacity. Moreover, a traditional regulatory response to high volatility in a market is the establishment of price caps. In connected markets, price caps should be a agreed upon by consensus, whose estimate should include markets that are not directly connected; otherwise, in a period of scarcity power flows would be in the direction of the higher price cap. In short, given the interactions and constraints in the electric system, co-ordinated policies and information sharing between connected electricity markets are vital.

Currently, different national policies for integrating RES-E are in place and there is variation in how nations are dealing with their capacity assessments. In fact, the European market coupling project does not address capacity, and its independence from capacity assessments can be problematic in the long run. Electricity, at the end of the day, is a common good: faced with local social and institutional pressures national governments react and quick reactions in interconnected energy markets can have unwanted consequences. Overall, the ability of an integrated energy market to secure supply and minimize the cost to consumers call for greater coordination and innovation in policy and regulation at the European level. National policies are responsible for securing supply and energy mixes are decided by each state, where institutional pressures may not allow policy makers enough time for consultations. However, in the absence of a coordinated European-wide capacity assessment, the resilience of the electricity markets to shocks that could result from market integration is constrained. In fact, the findings of this study also highlight the potential for volatility transmission across energy markets, especially in the direction of the gas market, which should be further investigated and monitored.

In conclusion, the present study highlights challenges associated with isolated energy policies in the context of achieving the goals of a single European electricity market and RES-E targets. A fully co-ordinated European approach to energy policy appears indispensable, but clearly is not easily achievable. Nonetheless, a single Europe-wide capacity assessment of national policies, in the interim, would enable each electricity market to estimate the consequences of their policies in other markets and anticipate reactions from different perspectives. Moreover, the greater sharing of information between the different market participants, regulators and policy-makers that such an assessment would require could also facilitate monitoring of the behaviour of dominant market participants and help in removing barriers to full market coupling. Hence, a single Europe-wide capacity assessment is needed and would be a significant step forward in the path to an integrated energy market in Europe.

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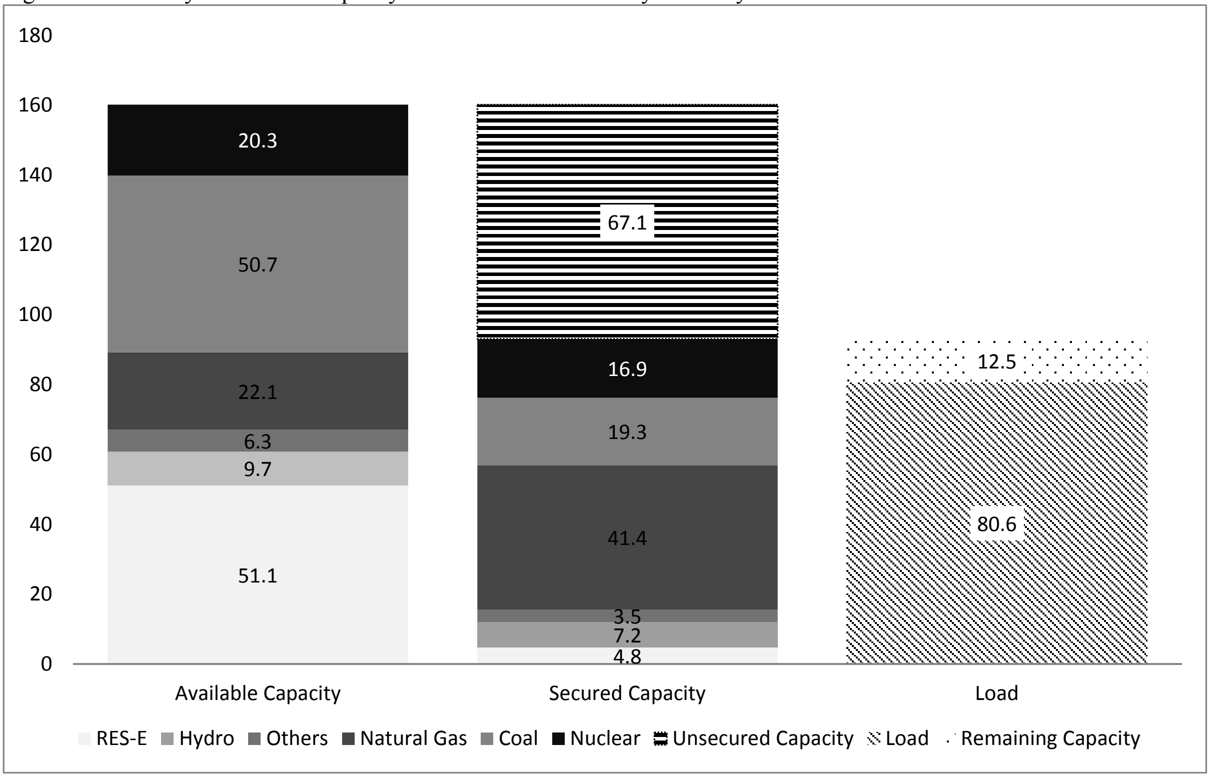
Figure 1: Electricity Generation Capacity & Peak Load in Germany - January 2011.



Source BDEW, 2011.

Figure 2: Order of Integration (*d)* of Electricity Spot Prices – time series from January to November 2012.

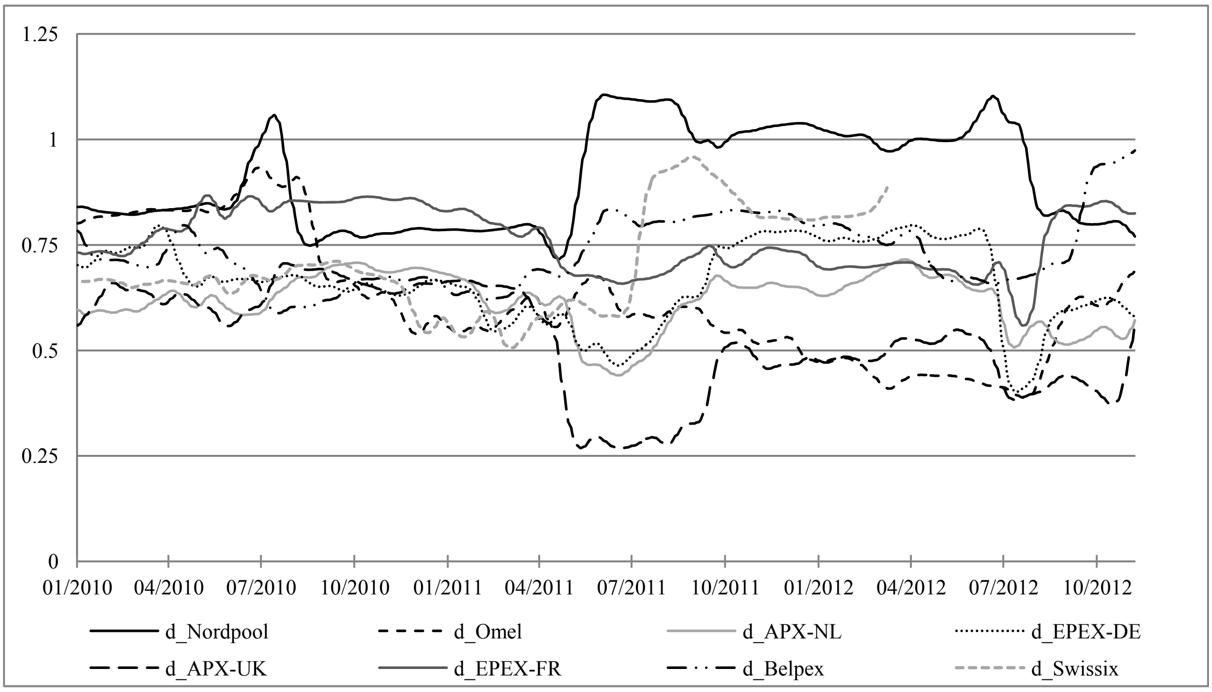


Table 1: Summary statistics – spot prices in the different markets and wind power penetration in Germany

	Min	Mean	Max	Std. Dev	Skew.	Kurt.
APX-NL	21.04	50.08	98.98	7.7	0.32	3.24
APX-UK	30.52	52.12	130.81	8.81	1.46	11.27
BELPEX	15.11	49.86	111.92	9.53	0.94	5.76
EPEX-DE	7.21	48.98	98.98	8.61	0.17	2.84
EPEX-FR	15.13	51.04	367.60	15.65	11.45	219.22
NORDPOOL	7.94	45.21	134.8	16.61	0.63	1.55
OMEL	3.13	44.50	67.35	10.18	-1.05	1.49
SWISSIX	15.66	55.33	155.32	11.63	1.85	13.27
Wind Power	0.01	0.18	0.86	0.13	1.37	2.42
Planned Wind Power	0.02	0.19	0.85	0.13	1.30	2.11

Minimum (Min), mean, maximum (Max) and standard deviation (Std. Dev); skewness (Skew.), excess kurtosis (Kurt.); prices in €/MWh.

Table 2: Summary statistics and estimated speed of mean reversion of smoothed spot price time series

	Min	Mean	Max	Std. Dev	Skew.	Kurt.	d
APX-NL	36.36	52.49	98.98	6.79	1.17	7.82	0.695
APX-UK	41.5	54.83	100.21	6.24	1.84	12.48	0.489
BELPEX	25.38	52.12	111.92	9.14	1.59	10.46	0.835
EPEX-DE	27.67	51.5	98.98	8.01	0.69	5.92	0.615
EPEX-FR	25.38	52.49	147.25	10.75	2.98	22.25	0.906
NORDPOOL	7.94	45.10	103.25	17.46	0.4	3.35	0.862
OMEL	16.16	49.49	65.31	6.60	-0.78	5.66	0.614
SWISSIX	31.05	57.47	155.32	11.98	2.41	18.44	0.782

Minimum (Min), mean, maximum (Max) and standard deviation (Std. Dev); skewness (Skew.), excess kurtosis (Kurt.); prices in €/MWh; d is the order of integration estimated using the FELW estimator with m=0.75: the higher this value the lower is the speed that the series reverts to its mean.

Table 3: TDCC Average Correlations – Before 6 August 2011 (top triangle) & After 6 August 2011 (bottom triangle)

	1	2	3	4	5	6	7	8	9
1 EPEX-FR		0.47***	0.61***	0.00	0.20	0.53***	0.12	0.84***	-0.06
2 EPEX-DE	**0.85*****		0.51***	0.10	0.02	0.32*	0.03	0.43***	-0.43***
3 APX-NL	**0.86*****	**0.89*****		0.16	0.24	0.46***	0.15	0.71***	-0.28***
4 NORDPOOL	0.33***	0.37***	0.31***		0.00	0.05	0.18	-0.05	-0.15
5 OMEL	0.26***	0.22***	0.17***	0.10		0.16	-0.09	0.33*	0.04
6 SWISSIX	0.71***	**0.75*****	0.73***	0.29***	0.17***		-0.10	0.42***	-0.11
7 APX-UK	0.24***	0.22***	0.24***	0.07	0.00	**0.21*****		0.15	0.06
8 BELPEX	**0.97*****	**0.85*****	0.9***	0.30***	0.24	0.73***	0.25***		-0.06
9 **Wind Power**	**-0.41*****	-0.56***	-0.48***	-0.29***	-0.08	-0.31***	-0.15***	**-0.30*****	

*, **, *** 10%, 5% and 1% significance level; significant changes in bold.

Table 4: TDCC Average Correlations – Before 6 August 2011 (top triangle) & After 6 August 2011 (bottom triangle)

	1	2	3	4	5	6	7	8	9
1 EPEX-FR		0.68***	0.79***	0.28***	0.22***	0.59***	0.21***	0.99***	-0.14***
2 EPEX-DE	**0.84*****		0.82***	0.39***	0.12**	0.54***	0.21***	0.68***	-0.48***
3 APX-NL	**0.86*****	**0.89*****		0.35***	0.16***	0.64***	0.25***	0.8***	-0.42***
4 NORDPOOL	0.34***	0.37***	0.32***		0.00	0.25***	0.19***	0.29***	-0.20***
5 OMEL	0.25***	0.22***	0.17**	0.11		0.24***	-0.02	0.22***	-0.01
6 SWISSIX	**0.71*****	**0.75*****	0.73***	0.29***	0.17		0.18***	0.60***	-0.25***
7 APX-UK	0.24***	0.21***	0.23***	0.07	0.00	0.21***		0.22***	-0.11
8 BELPEX	0.97***	**0.85*****	0.90***	0.31***	0.24***	**0.73*****	0.25***		-0.15***
9 **Planned Wind Power**	-0.40***	**-0.54*****	-0.45***	-0.30***	-0.09	-0.29***	-0.14***	**-0.37*****	

*, **, *** 10%, 5% and 1% significance level; significant changes in bold.

Table 5: EDCC Average Correlations - Before 6 August 2011 (top triangle) & After 6 August 2011 (bottom triangle)

	1	2	3	4	5	6	7	8	9
1 EPEX-FR		0.71***	0.83***	0.26***	0.21***	0.58***	0.19***	1.00***	-0.18***
2 EPEX-DE	**0.84*****		0.83***	0.39***	0.11*	0.54***	0.19***	0.71***	-0.42***
3 APX-NL	0.86***	0.88***		0.32***	0.15*	0.65***	0.23***	0.84***	-0.40***
4 NORDPOOL	0.29***	0.34***	0.27***		0.01	0.22***	0.21***	0.27***	-0.19***
5 OMEL	0.24***	0.20***	0.15***	0.09		0.20***	-0.01	0.20***	0.01
6 SWISSIX	**0.69*****	**0.72*****	0.70***	0.27***	0.16**		0.15***	0.58***	-0.26***
7 APX-UK	0.25***	0.23***	0.24***	0.08	-0.02	0.20***		0.20***	-0.11*
8 BELPEX	**0.97*****	**0.84*****	0.90***	0.26***	0.22***	**0.71*****	0.26***		-0.18***
9 **Wind Power**	**-0.43*****	**-0.58*****	-0.49***	-0.28***	-0.08	-0.31***	-0.15***	**-0.41*****	

*, **, *** 10%, 5% and 1% significance level; significant changes in bold.

Table 6: EDCC Average Correlations – Before 6 August 2011 (top triangle) & After 6 August 2011 (bottom triangle)

	1	2	3	4	5	6	7	8	9
1 EPEX-FR		0.72***	0.84***	0.26***	0.20***	0.58***	0.19***	1.00***	-0.18***
2 EPEX-DE	0.84***		0.83***	0.39***	0.10	0.54***	0.20***	0.72***	-0.46***
3 APX-NL	0.86***	0.88***		0.32***	0.15***	0.65***	0.23***	0.84***	-0.42***
4 NORDPOOL	0.30***	0.34***	0.28***		0.01	0.22***	0.20***	0.26***	-0.20***
5 OMEL	0.24***	0.20***	0.15**	0.09		0.20***	-0.01	0.19***	-0.01
6 SWISSIX	0.68***	**0.72*** **	0.70***	0.28***	0.16***		0.15***	0.59***	-0.28***
7 APX-UK	0.25***	0.22***	0.24***	0.08	-0.02	0.20***		0.20***	-0.10*
8 BELPEX	**0.97*** **	**0.84*****	**0.90*** **	0.27***	0.22***	**0.71*** **	0.26***		-0.18***
9 **Planned Wind Power**	**-0.42*** **	-0.55***	-0.46***	-0.29***	-0.09	-0.29***	-0.15***	**-0.39*** **	

*, **, *** 10%, 5% and 1% significance level; significant changes in bold.

Table 7: Estimated order of integration (speed of mean reversion) - one year before and one year after 6 August 2011

		Mean (Confidence Interval)	t-statistics
1 EPEX-DE	d_before	0.591 [.458; .728]	2.130**
	d_after	0.736 [.603; .870]	
2 BELPEX	d_before	0.792 [.658;.925]	2.847**
	d_after	0.985 [.852; 1.119]	
3 APX-NL	d_before	0.624 [.491; .758]	4.225***
	d_after	0.912 [.778; 1.045]	
4 EPEX-FR	d_before	0.793 [.660;.926]	2.994**
	d_after	0.996 [.863; 1.130]	
5 OMEL	d_before	0.571[.438; .710]	0.862
	d_after	0.629 [.496; .827]	
6 SWISSIX	d_before	0.665[.532; .763]	5.921**
	d_after	1.068[.935; 1.202]	
7 NORDPOOL	d_before	0.784 [.651; .918]	1.708*
	d_after	1.012 [.879; 1.146]	
8 APX-UK	d_before	0.623[.490; .736]	3.429***
	d_after	0.395 [.262; .528]	

Order of integration is denoted d. The asterisks *, ** and *** denote 10%, 5% and 1% significance levels, respectively.

Table 8: Tests of differences in order of integration between spot prices in pairs of markets

	1	2	3	4	5	6	7	8
1 EPEX-DE		-2.944**	-0.484	-2.959**	0.304	-1.088	0.784	1.087
2 BELPEX	-3.662**		2.460**	-0.015	3.249**	1.856	0.106	1.880
3 APX-NL	-2.581**	1.081		-2.475**	0.788	-0.604	-2.354**	0.602
4 EPEX-FR	-3.824	-0.162	-1.243		2.400**	1.871	0.121	-1.866
5 OMEL	1.572	5.234**	4.153**	5.396**		-1.393	-3.143**	-1.748
6 SWISSIX	-4.884**	-1.222	-2.31**	-1.060	-6.456**		-1.75	1.381
7 NORDPOOL	-4.057**	-0.396	-1.477	-0.234	-5.629**	-0.826		0.617
8 APX-UK	-5.009**	-8.829**	-7.595**	-8.668**	-9.064**	-3.437**	-9.886**	

Null hypothesis: Common order of integration *d* of market *i* and market *j*, *i*, *j*=1, 8. Before (top triangle) and after (bottom triangle) 6 August 2011. The asterisks ** denote t-statistic significant at 5% significance level.

Table 9: Tests of cointegration between pairs of spot prices with common order of integration

	1	2	3	4	5	6	7	8
1 EPEX-DE			0.191**		0.571	0.425**	0.791	0.449
2 BELPEX				0.184**		0.467**	0.665	0.590
3 APX-NL		0.389 **		0.564	0.590	0.499		0.457
4 EPEX-FR		0.250**	0.574**		0.826	0.472**		0.592
5 OMEL	0.701					0.532		0.464
6 SWISSIX		0.644**		0.496 **			0.781	0.515
7 NORDPOOL		0.446 **	0.447 **	0.240**		0.638**		0.567
8 APX-UK								

Order of integration *d* for residual series z_t for all market pairs that share a common order of integration. Before (top triangle) and after (bottom triangle) 6 August 2011. The asterisks ** denote 5% significance level.