Time-Varying Convergence in European Electricity Spot Markets and their Association with Carbon and Fuel Prices

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Highlights:

- The Localised Autocorrelation Function (Nason, 2013) is used to assess the changing nature of electricity spot prices
- EU electricity spot prices show stationary as well as non-stationary periods that may reflect their association with inputs to electricity generation.
- Carbon and fuel prices are likely to have greater impact on British spot prices than prices in linked electricity markets.
- In continental Europe, electricity prices appear to have decoupled from fuel prices and associations between electricity spot prices in different markets is increasing

Abstract:

Long run dynamics of electricity prices are expected to reflect fuel price developments, since fuels generally account for a large share in the cost of generation. However, an integrated Pan-European market for electricity is in the process of being formed, which implies that wholesale electricity prices in European markets should be converging. Together with recent market coupling and increases in interconnector capacity, strategies that aim to significantly increase the share of renewables in electricity generation are in place and electricity mixes are changing. It is therefore likely that the fuel- electricity price nexus has been altered. Using daily peak and base load electricity spot prices from December 2005 to October 2013 from the British, the French and the Nordpool (Norway, Denmark, Sweden, Finland, Estonia, Latvia and Lithuania) markets, the associations between fuel prices, spot prices locally and in neighbouring electricity markets are investigated. In order to examine the time-varying dynamics of electricity spot price series, localized autocorrelation functions, a statistical measure that can identify changes in autocorrelation and thus identify stationary and non-stationary periods in a time series is employed. Cointegration analysis is used to assess co-movement between electricity spot prices and fuel inputs to generation during non-stationary periods. British electricity spot prices are found to move with fuel prices and not with neighbouring markets, while in the French and Nordpool day-ahead markets are less influenced by fuel prices, and spot prices movements are correlated with interconnected electricity markets.

Keywords: *Electricity market integration, long run dynamics, localized autocorrelation function*

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1. Introduction

In Europe, natural gas, coal and carbon prices have been found to be associated with electricity price movements by several researchers (Aatola, 2012; Asche et al., 2006; Bollino et al., 2013; Mjelde & Bessler, 2009), as their costs can correspond to over 70% of electricity spot prices (Crampes and Fabra, 2005). Most EU member states, however, have very limited fossil fuel resources that can be used for electricity generation at the scale that is required. In recent years, concerns over the dependency on foreign fuel imports have increased, despite growing shares of electricity from renewable energy sources (RES-E), as conventional back-up capacities are needed to match the increasing share of intermittent output.

An increase in future fuel prices, or energy supply disruptions could adversely affect electricity prices, if they are associated. Depending on the strength of association between electricity and conventional fuel prices, uncertainty about the latter could impair Europe's economic competitiveness, as the cost of electricity is an important input factor in almost any industry. In fact, electricity intensive industries have already moved from the EU to regions, where it is less costly. In order to achieve cost efficient electricity prices, a well- functioning internal European electricity market has been recognized as a key instrument. A Pan European electricity market implies regional integration, harmonization of trading rules, increased cross border electricity transmission capacities and trade (European Commission, 2013). Therefore, from the perspective of assessing electricity market integration in the EU, strong associations between fuel and electricity prices could impact on electricity price convergence and vice versa.

The aim of this study is to link research on electricity market integration and associations between electricity and fuel as well as carbon prices. The research is carried out in a time-variant framework in order to understand dynamics that might have been neglected and possibly led to mixed findings that are reported in the literature. We therefore examine the long run dynamics and convergence in three European markets, where the reliance on fossil fuels for electricity generation varies, namely: APX-UK (Great Britain), EPEX-FR (France) and the Nordpool (Norway, Denmark, Sweden, Finland, Estonia, Latvia and Lithuania). For this purpose, we develop a two-stage analysis, where first we assess stationary and non-stationary periods of electricity spot prices using a statistical method (Cardinali and Nason, 2013) which can accommodate the time varying serial correlation, and, secondly, cointegration analysis to assess convergence with fuel, carbon and other electricity markets (Johansen, 1988, 1991; Stock and Watson, 1988).

The paper is structured as follows: section two reviews the literature that addresses electricity market integration and assessments of fuel, carbon and electricity price associations and defines the knowledge gap. The third section introduces the contextual framework of the research and the research question is outlined. The fourth section describes the analysis procedure and methods. In the fifth section the dataset is presented. Results are detailed in section six and discussed in section seven. The paper concludes with section eight.

2. Literature Review

There is a growing body of literature on common long run dynamics in energy markets and a subset of studies that focus on the integration of fossil fuel and electricity prices. In general, integration is demonstrated by establishing price convergence over time, which is then interpreted as efficiency gains that are obtained when the marginal costs of production are equal in different regions (Engle and Rogers, 2004). Related studies are classified as follows: (1) investigations of electricity market integration, (2) assessments of electricity and fuel price convergence and (3) investigations of electricity market integration, fuel and carbon price developments. The next subsections review each category and conclude with a reflection on the limitations of previous research and implications for future research, including the present study.

2.1. On electricity market integration

The Law of One Price (Fetter, 1924) has been the core theoretical foundation in assessing common long run dynamics in liberalized electricity markets. Following the initial evaluations (Bower, 2002; Boisselau, 2004), several studies (e.g. Armstrong and Galli, 2005; Boeckers and Heimeshoff, 2012; Bunn and Gianfreda, 2010; Robinson, 2008; Zachmann, 2008; Pellini, 2012) have assessed electricity price convergence in the EU. Their findings suggest that the average price difference between markets decreased in almost all cases, and more rapidly in peak load periods (with the exception of Bunn and Gianfreda, 2010). Interconnection and geographical distances between electricity markets were found to be crucial for price convergence. Most authors concluded that the integration of European markets has *"still a way to go"* (Pellini, 2012:1). However, the detailed studies on electricity market integration neglected the potential relevance of the local electricity mix, which could impact on convergence. Studies assessing relationships between electricity and fuel prices are therefore reviewed in more detail in the following section.

2.2. On associations between fuel and electricity prices

Since the initial evaluations by Serletis and Herbert (1999), several studies addressed the associations between generation fuels (such as natural gas, coal, crude oil and uranium) and electricity prices. For example, Brown and Yücel (2008), Emery and Liu (2002), Mjelde and Bessler (2009), Nakajima and Hamori (2013) and Woo et al. (2006) analyzed different U.S. markets and observed a positive correlation between natural gas and electricity prices, which was also more pronounced during peak periods.

In the specific case of liberalized European markets, Asche et al. (2006) analyzed the British market and used cointegration analysis for monthly crude oil, natural gas and electricity wholesale prices in the period from 1995 to 2002. Interestingly, the authors found an integrated energy market only during 1995 to 1998, when the natural gas market was deregulated but not yet physically linked to continental Europe by an interconnector. They inferred that prices could have decoupled in the second period, because of an incomplete regulatory structure or insufficient transmission capacity. Bollino et al. (2013) reasoned that even if from a physical viewpoint the possibility to exercise arbitrage is limited, it is conceivable that fuel price information, which is available at the strategic decision center of a big multinational electricity generation company, can be shared throughout its subsidiaries acting in different markets. This would simulate integration.

In Spain, Moutinho et al. (2011) as well as Furio and Chulia (2012) also examined convergence between fuels and electricity prices for the spot and 1-month ahead markets, respectively. Moutinho et al. (2011) used daily price data from 2002 to 2005 and established cointegration between the Spanish electricity spot and natural gas prices, as well as for coal prices but not for oil prices. Furio and Chulia (2012), using data from 2005 to 2011 found full integration of fuel (oil and natural gas) and electricity prices in the month-ahead market. Their findings are in line with Munoz and Dickey (2009), who stated that natural gas, coal and oil, in this order, were the main components of Spanish electricity generation as well as of electricity prices.

Bencivenga et al. (2010) linked the research conducted in the US and the EU by comparing the associations between crude oil, natural gas and electricity prices (in each case one representative time series) in both markets. Using daily price data over the period from 2001 to 2009, their results suggest different convergence behavior in the US compared to the EU. The authors said that besides the efforts of the European commission they found integration in the EU to be lower compared to the US. Bencivenga et al. (2010) explained their finding by incomplete deregulation in the European market, exercise of market power and self-governing gas price behavior which is associated with conditions and circumstances in fuel supplying countries.

Simpson and Abraham's (2012) study added to the existing literature by assessing electricity market and energy sector decoupling (regulation) versus convergence (deregulation/ liberalization). The authors compared the electricity and energy markets of a large country sample (from OECD, Latin America and Asia) from 2000 to 2011. They reason that the strength of the integrating relationship between fuel and electricity prices should be indicative of greater progress of electricity market liberalization. The results of the study showed that larger economies, whether developed or undeveloped, demonstrated stronger relationships between fuel and electricity prices, and thus a greater degree of liberalization was due to less price manipulation through monopolies. The findings of the study further suggested that a heavy use of renewable electricity sources and its regulatory cost reduced convergence.

The findings of the studies on energy market integration demonstrate that associations between fuel and electricity prices are relevant for long run dynamics in electricity prices and should therefore be considered when assessing electricity market integration.

2.3. On electricity market integration and fuel and carbon price associations

Among evaluations of electricity market integration, only a few researchers have addressed dependencies with fuel prices. For example, Kalantzis and Milonas (2010)'s analysis of eight EU electricity spot markets between 2006 to 2009 concluded that rising oil prices indirectly excerpt a positive impact on price convergence, due to the substitution with indigenous energy sources. They found this effect more pronounced during off-peak hours, where the interconnection capacity was not fully utilised and congestion less frequent. Bollino et al. (2013) in contrast established no effect of oil prices for the cointegrating relationships of French, German and Italian electricity spot markets between 2004 and 2010 and concluded that oil prices were not relevant for the investigation of electricity market integration.

Including renewables to their assessment of convergence between fuel and electricity prices, Ferkingstad et al. (2011) investigated dynamics between Nordpool and German electricity prices, major fuel sources (oil, natural gas and coal), as well as two exogenous renewable variables (wind electricity production and water reservoir levels) between 2002 and 2008. Similar to previous single market studies, their findings confirmed a strong connection between natural gas and electricity prices, whereas the price of coal was not found to play an important role. In line with this, Bosco et al. (2010) found strong evidence of common long run dynamics between electricity and natural gas prices in four European markets between 1999 and 2007. Just as Bollino et al. (2013), the authors could not find any association with oil prices. Contrary to their conjecture for the British, German, Austrian and French electricity spot market and, despite significant differences in mix of generation technologies, the authors discovered that the use of a common marginal generation source (natural gas) prevails as the most important force in the determination of long-run relationships of the electricity prices.

The introduction of the EU Emissions Trading Scheme (EU ETS) in 2005 marked an important change in EU energy policy. Since then, greenhouse gas emission allowances traded over 45% of the EU's carbon gas emissions (European Commission, 2014b). Electricity generators therefore do not only observe fuel price developments but also pay close attention to carbon prices when scheduling their plants (Chevallier, 2012). Several researchers (e.g. Fezzi and Bunn, 2010; Sijm et al., 2006; Pinho and Madaleno, 2011) analysed how carbon costs are linked to electricity prices. Pinho and Madaleno (2011) used monthly data from 2005 to 2009 and examined the interactions between carbon, electricity and fuel prices in Germany, France and Nordpool by means of a Vector Error Correction Model. They found the impact of carbon prices to depend on the countries' energy mixes. Aatola et al. (2013) laid a first primer on assessing the effect of carbon prices on the integration of European electricity markets using Granger causality, correlation and cointegration analysis. Comparing three sub periods, they suggested that the impact of the carbon price on electricity market integration varies, depending on the energy mix, the marginal electricity plant and time. Their findings suggested that carbon prices had a positive but uneven effect on electricity prices integration.

In summary, the detailed literatures mainly look at one aspect of liberalized electricity markets in isolation: integration with other markets or convergence with fossil fuel or carbon prices. Despite possible interactions a link between the literatures has not been established. For example assessments of electricity market integration found more convergence during peak compared to base load periods, despite the higher chances of congestions in transmission lines during peak periods. This finding might be explained with studies on fuel and electricity price convergence which agreed on stronger associations during peak periods. Greater convergence of electricity wholesale prices could therefore have been driven indirectly by fuel price associations.

Furthermore, previous findings indicate that convergence should be changing over time as associations depend on the local electricity mix, the degree of regulation and the size of the market. Nonetheless, time independent approaches have been chosen. Cointegration analysis was broadly applied to assess convergence and was at most employed to three sub-periods to capture changes in time (Aatola et al., 2013). Another limitation in cointegration analysis is the required non-stationarity of the data. Meeting this criteria has led previous research to either aggregate the frequency of the data (e.g. Bosco et al. 2010; Ferkingstad et al., 2011; Mjelde and Bessler, 2009) or to employ related price indices, such as prices paid by consumers (e.g. Simpson and Abraham, 2012).

Inferences of possible implications for and from electricity market integration or time-dependency were not included in earlier assessments. The aim of this study is to address this gap.

3. Contextual background of European electricity markets

3.1. Electricity mix in European markets

The local electricity mix is likely to be relevant for electricity market integration because of the price setting mechanism as well as the possibility for arbitrage in the case of complementary electricity generation portfolios (Teusch, 2012). The bid of a conventional electricity generator to the exchange reflects the variable cost of the fuel that is used for production as well as the carbon price, which electricity companies also need to consider when scheduling their plants. This is the case even if the allowances are granted for free as they represent opportunity costs (Sjim et al, 2011).

Conventional generators are scheduled by the system operator to meet demand by dispatching the generators with the lowest marginal generation cost first and then moving up the dispatch curve, calling on generators with higher marginal costs until demand is satisfied. Thus, if there are no constraints in the transmission lines, the electricity spot price will be set by the marginal producer. In a cost reflective market, input prices in electricity generation should therefore at least be partially reflected in electricity prices and, for markets with a large share of a specific marginal fuel in its electricity mix, associations are expected to be stronger (Furió and Chuliá, 2012).

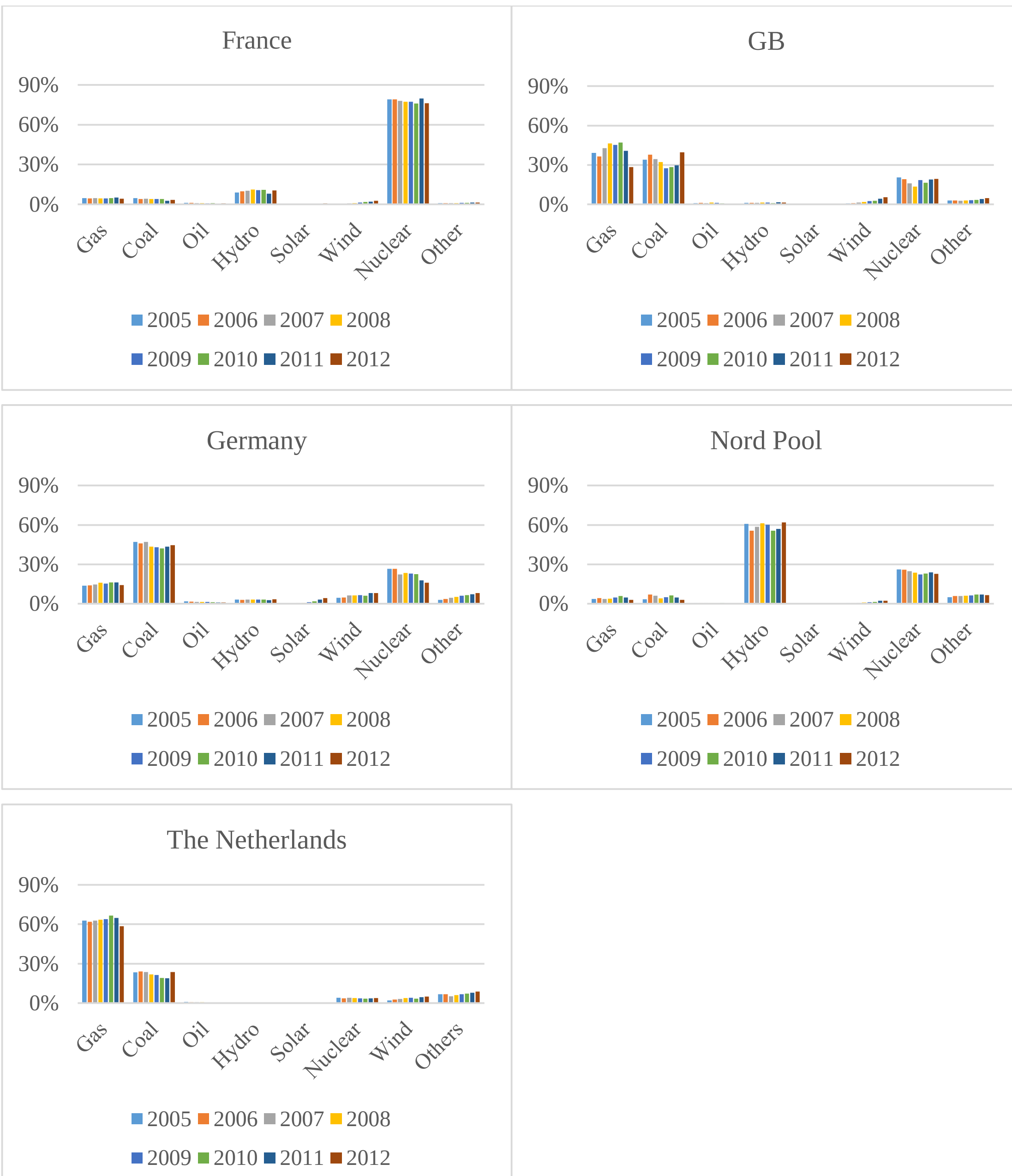
Figure 3.1 presents the development of gross electricity generation between 2005 and 2012 in the five markets (France, GB, Germany, Nordpool and The Netherlands) that will be examined. The French electricity mix is characterised by the highest share of nuclear generated electricity within the markets. The share fluctuated between 76% and 80% in the years between 2005 and 2012. In 2012, 11% of the domestic electricity was generated by hydro, 4% by gas followed by wind and coal generated electricity (3% each).

In Britain large but declining quantities of gas were used to generate electricity between 2005 and 2012. The share of coal on the other hand has increased from 2011 to 2012 from 30% in 2011 to 40% in 2012. Nuclear generated electricity contributed around one fifth of gross electricity output between 2005 and 2012. However, this electricity mix is likely to change as the Large Combustion Plant Directive will lead to a closure of 12GW by 2016, further closures are expected before 2016, enforced by the EU Industrial Emission Directive (IEA, 2012).

The largest component in the German electricity mix is coal, with a share of 45% in 2012. More than 16% of the local electricity mix in 2012 consisted of nuclear generated electricity. However, since 2006, a decline in nuclear power output can be observed from 167TWh to 100TWh in 2012. This development reflects the implementation of the Atomgesetz, which foresees the closure of all nuclear power plants by 2022. The legislation of the EEG (Erneruerbare Energien Gesetz) in 2000 has led to rapid growth, especially of biomass, photovoltaics and wind energy.

The Nordpool market is characterised by a large share of seasonal hydro generated electricity. Overall, Nordpool has almost 130TWh hydro capacity, of which 63% is installed in Norway, 26% in Sweden and 11% in Finland (NordpoolSpot, 2014). In the Netherlands the highest share of gas and coal in the local electricity mix can be found, and varies over time.

Figure 1: Gross Electricity Generation Mix in the markets under study from 2005 to 2012



Source: Eurostat, 2014

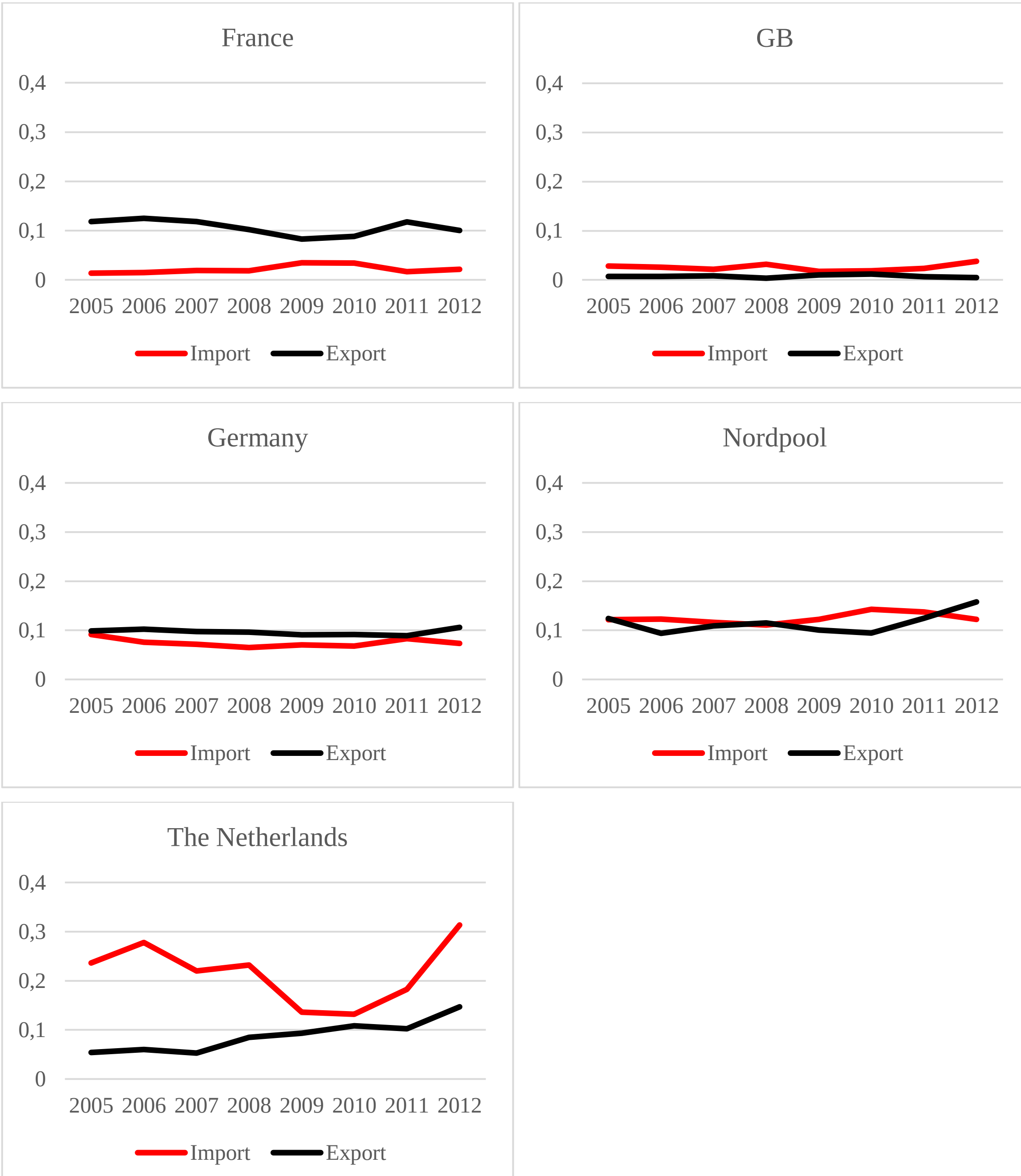
In summary, we observe significant differences in the local electricity mixes which are changing, responding to local and EU energy policies that aim at decarbonising the electricity sector and increasing the share of RES-E.

3.2. *Electricity trade in the EU*

Besides the aim to decarbonise the electric system some electricity markets have been integrated via market coupling, which is the use of implicit auctioning involving two or more power exchanges. For example, the Trilateral Market Coupling, couples the Belgian, Dutch and French electricity market since November 2006. The Interim Tight Volume Coupling links the Belgian, Dutch, French and German electricity markets with Nordpool since 9 November 2010.The British market, though interconnected with three other markets, is not coupled to any other European market.

Different levels of interconnectivity in the markets are also reflected in Figure 2, where the ratio of imports to total electricity generation as well as exports to total electricity generation between 2005 and 2012 are depicted. The Netherlands is a major electricity transit country due to its central location in Europe. This explains the highest values of import and export shares of the total Dutch electricity generation, which reached almost 32% and 15% respectively. In the German and the Nordpool market imports and exports fluctuated around 10% of the overall generated electricity between 2005 and 2012. In France exports ranged between 9% and 13% from 2005 to 2012, however imports were much smaller with the highest value of only 4% in 2009 and 2010. The British market stands out from the sample as the one with the lowest shares of imports and exports expressed as a share of total domestic electricity generation: British electricity exports were less than 1% and imports at most 3% between 2005 and 2012.

Figure 2: Import and export as a ratio of total electricity generation in the markets under study from 2005 to 2012



Source: Eurostat, 2014

3.3. *Electricity spot price dynamics*

Besides differences in electricity mix and interconnectivity, a common characteristic of electricity prices is noteworthy for the present study. Electricity spot prices dynamics have often been found to be stationary or mean-reverting processes (e.g. Escribano et al., 2002; Haldrup and Nielsen, 2006; De Jong and Huisman, 2002; Deidersen and Trueck, 2002; Husiman and Mahieu, 2003; Koopman et al., 2007), unlike most fuel price series that tend to follow a trend. Mean reversion implies stationarity as it describes the tendency of variables to revert back to their long-run mean. With each successive movement away from the long-run average, the likelihood that the next electricity price movement will be toward the average increases (Marshall, 2000). One aim of electricity market integration is to increase the speed of mean reversion of electricity prices, which would indicate greater resilience against unexpected supply or demand shocks. A quick speed of mean reversion or stronger stationary behavior implies robustness and flexibility of the electric system in the sense that additional capacities are brought online quickly and prices revert to their normal levels as expensive plants are swiftly replaced. By contrast, persistent prices would indicate that shocks are less easily overcome.

Any assessment of price convergence via standard cointegration analysis (Johansen, 1988, 1991), requires that the time series are at least integrated of order one (*I(1)*). This long run price behavior contradicts the aim of electricity market integration, which is greater flexibility or faster mean reversion. With increasing market integration, long run behaviors of electricity spot prices could be changing: from non-stationarity due to associations with mainly non-stationary fuel prices towards increasing periods of mean-reversion facilitated by the availability of local and neighbor market capacities.

All in all, the differences in local electricity mixes as well as in levels of electricity trade put forward that fuel, carbon and electricity prices in neighbouring markets may not have the same relevance for price dynamics and convergence in the markets under study. We therefore address the following research question: Has electricity market integration in Europe reduced associations between fuel and electricity spot prices?

4. Methods

4.1. Analysis procedure

Prior to the empirical analysis, outliers are replaced with the mean average over a four week period. An outlier is defined as a value exceeding three standard deviations of the mean average over a four week window. All time series behavior is then summarised and assessed for stationarity and trends, via unit root tests and estimates of the order of integration. The methods are described in 4.2. Serial correlation of the electricity spot price time series are examined via estimates of the localised aurocorrelation function (LACF), as detailled in section 4.3. Having identified potential non-stationary periods, as those where the absolute values of LACF of lags 1 to 20 are greater than 0.8- a threshold to the unit circle that defines statitionarity-, a unit root test is used to confirm or reject non-stationarity. Within periods where a unit root is confirmed, a cointegration analysis of neighbouring electricity spot prices, fuel inputs and carbon prices is performed, as described in section 4.4. We differentiate between peak and off-peak hours because they are characterised by different price dynamics, as the more expensive and flexible generation units would normally be allocated at peak periods.

4.2. *Assessing trends: tests for integration and fractional integration*

The Augmented Dickey Fuller test (ADF) and the Phillips and Perron test (PP), which have been proposed by Dickey and Fuller (1979, 1981) and Phillips and Perron (1988) respectively are used to test the alternative hypothesis of a mean reverting stationary series against the null hypothesis of a trendy *I(1)* time series. The tests are conducted up to the optimal lag length *l* which in this study is selected based on the Akaike Information Criteria (AIC). We also estimate the order of integration to assess long memory time series behaviour. By definition, a process X_t is said to be *I(d)* if its fractional difference, $(1-L)^d X_t$, is an *I(0)* process. The fractional difference operator $(1-L)^d$ is defined as follows:

$$(1-L)^d = \sum_{k=0}^{\infty} \frac{\Gamma(k-d)L^k}{\Gamma(-d)\Gamma(k+1)}, \quad (1)$$

where *d* can take any real value and governs the long run dynamics of an *I(d)* process. For $-\frac{1}{2}<d<\frac{1}{2}$ the process is stationary and invertible, for $d>\frac{1}{2}$ the process is non-stationary but mean-reverting when $\frac{1}{2} \leq d<1$ (Robinson, 1994). In the present study, we employ the semi-parametric two-step Feasible Exact Local Whittle (FELW) estimator by Shimotsu (2006) as well as the s GPH (Geweke and Porter- Hudak, 1983) estimator to estimate the order of integration *d*. The FELW estimator has been described as robust against misspecification of the short run dynamics of a process (Okimoto and Shimotsu, 2010). Another advantage of the FELW is that it accommodates both stationary ($d<$ ½) and non-stationary ($d\geq$ ½) processes, so that there is no need to restrict the interval for *d* when analysing a time series. For the FELW estimator we set the bandwidth *m* equal to 0.75, as suggested by Lopes and Mendes (2006).

4.3. Identifying time-varying dynamics: Localized Autocorrelation Functions (LACF)

A locally stationary process is a non-stationary time series, with a time-varying spectrum. This kind of process is useful in describing time series whose properties change over time, thus allowing for the identification of periods that are locally stationary as well as other periods that are locally non-stationary. Following Nason et al. (2000), a stationary time series X_t can be represented as:

$$X_t = \int_{-\pi}^{\pi} A(w) e^{i\omega t} dz(w) \quad (2)$$

Where $A(w)$ is and amplitude function, $e^{i\omega t}$ is a system of harmonic complex exponentials and $z(w)$ is an orthogonal increments process. The amplitude function, $A(w)$, controls the variance of the time series. The usual spectrum $f(w) = |A(w)|^2$ and the spectrum and autocovariance are a Fourier transform pair.

Several extensions to the basic stationary model have been proposed to address non-stationarity of time series, such as the general class of models that are *locally stationary y*. These models replace the time invariant $A(w)$ term with an expression that explicitly depends on time, e.g. $A_t(w)$ (see for example Priestley (1983), Dahlhaus (1997); Dahlhaus and Polonik (2006) or Dahlhaus and Polonik (2009).The localized autocovariances, $c(z,\tau)$ are computed following Nason et al. (2000):

$$c(z,\tau) = \sum_{j=1}^{J} S_j(z)\psi_j(\tau), \quad (3),$$

where $\psi_j(\tau) = \sum_k \psi_{j,k}$ is the autocorrelation wavelet of the discrete non-decimated wavelet $\psi_{j,k}$ and $c(z,\tau)$ is the autocovariance of X_t at lag τ and at rescaled time $z = t/T$ for time points *t=1, ….T* where *T* is the length of the time series (Cardinali and Nason, 2013). The LACF estimates are computed with the costat package avaliable in *R* (Nason, 2013). The method requires the time series to be of a length that is a power of two, we therefore consider the longest possible sample length of 2048 observations.

Standard ACF can be used to determine stationarity. If the ACF falls immediately from 1 to 0, the series is stationary. If the ACF declines gradually from 1 to 0 over a prolonged period of time, then it is non stationary. We identify periods in the LACF where at least 20 consecutive days and the estimated coeffficients from the first to the 20th lag are greater than 0.8. This indicates that the time series are more likely to be non-stationary and cointegration analysis is carried out for that period which is introduced next.

4.4. Assessing Co-movement with fuel prices: Tests for Cointegration

Two time series x_t and y_t, integrated of order *d*, are said to be cointegrated of order (*d*, *b*) if the error correction term represented by the linear combination $z_t = y_t - \beta * x_t$ is integrated of order $d - b$, where $0 < b \leq d$. This study uses the VAR approach, which was developed by Johansen (1988, 1991) and Stock and Watson (1988) to assess cointegration. The general VAR (*k*) model can be written as:

$$\Delta y_t = \Pi y_{t-1} + \sum_{j=1}^{k-1} \Gamma_j \Delta y_{t-j} + \varepsilon_t \tag{4}$$

Where y_t is a vector of *I(1)* variables. The variables are said to be cointegrated if Π has less than full rank and is not equal to zero. In this case Π can be written as $\Pi = \alpha\beta^I$, where α and β are $n\ x\ r$ matrices. The rank of Π determines the number of independent rows in Π and therefore the number of independent cointegrating vectors given by the number of significant eigenvalues. Each significant eigenvalue represents a stationary relation. If Π is equal to zero, this means there is no cointegration. It can be shown that for a given *r*, the maximum likelihood estimator of β defines the combination of y_{t-1} that yields the largest canonical correlation of Δy_t with y_{t-1}.

The trace (λ_{trace}) and maximum eigenvalue (λ_{eigen}) tests in the bivariate case the null hypothesis of *r=0* cointegrating vectors (*not cointegrated*) against the alternative hypothesis of *r=1 (cointegrated*) cointegrating vectors (Johansen (1988), Stock and Watson (1988)).

$$\lambda_{trace}(r) = -T \sum \ln\left(1 - \tilde{\lambda}_i\right) \tag{5}$$

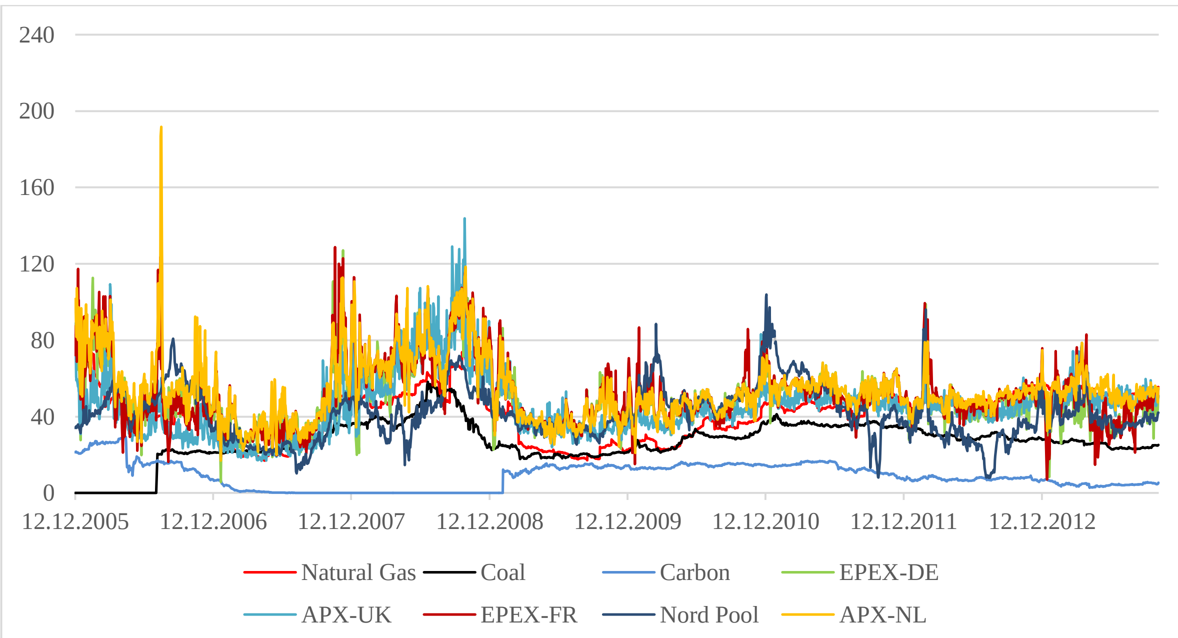
$$\lambda_{eigen}(r, r+1) = -T ln\, [1 - \tilde{\lambda}_{r+1}] \tag{6}$$

Here *T* is the sample size and λ_i is the *ith* largest canonical correlation. Neither of the tests follows a chi square distribution. Asymptotic critical values can be found in Johansen and Juselius (1990).

5. Data

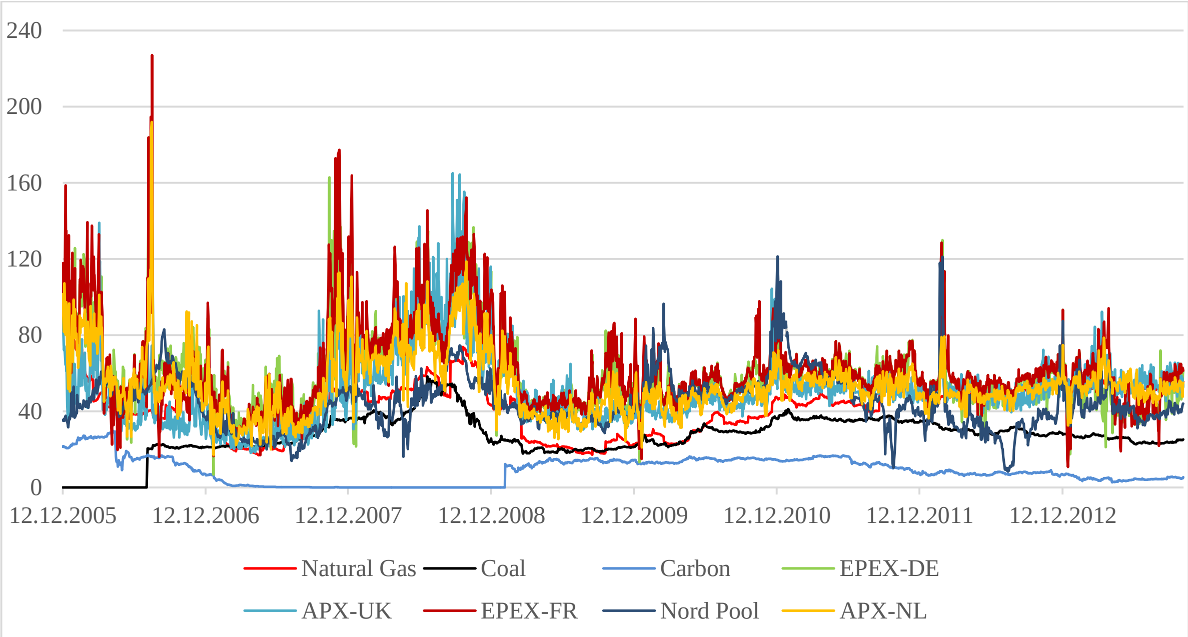
In this study we focus on the three electricity spot markets: APX-UK (GB), Nordpool (Norway, Denmark, Sweden, Finland, Estonia, Latvia and Lithuania) and EPEX-FR (France). In each case, we include two interconnected or coupled electricity markets (Germany and the Netherlands for GB; France and the Netherlands for Nordpool; Germany and GB for France) as well as API2 Coal (coal), London Natural Gas (natural gas) and EU ETS (carbon) prices. Figure 3 and 4 depict the plots of the electricity base load prices, fuel and carbon prices as well as electricity peak load prices and fuel and carbon prices in the day ahead market, respectively. Base load prices are the mean average of 24 daily price observations for week days only. Peak prices are mean averages covering the hours from 7am to 7pm for weekdays (APX, 2014).

Figure 3: Electricity base load, natural gas, coal and carbon prices



Electricity base load, natural gas and coal prices in €/MWh, carbon prices in €/EUA from 12.12.2005 to 16.10.2012.

Figure 4: Electricity peak load, natural gas, coal and carbon prices



Electricity peak load, natural gas and coal prices in €/MWh, carbon prices in €/EUA from 12.12.2005 to 16.10.2012.

Table 1 contains the summary statistics of the data that will be employed covering the period from the 12.12.2005 to 16.10.2013 for all series except coal, which began on the 17.07.2006. The week daily electricity base and peak load spot prices for GB (APX-UK), France (EPEX-FR), Germany (EPEX-DE), The Netherlands (APX-NL), the country group consisting of Norway, Denmark, Sweden, Finland, Estonia, Latvia and Lithuania (Nordpool), as well as prices for natural gas, coal and carbon certificates have been obtained from Datastream (Reuters, 2013). We exclude oil from the analysis as gas increasingly serves as a substitute, oil is indirectly included through gas prices, as they are highly correlated to (Moutinho et al., 2011, Furio and Chulia, 2012).

The summary statistics in Table 2 contain the mean, minimum, maximum, standard deviation, as well as number of observations for all series used. Estimated means of the time series are detailed in the 2nd row showing that on average electricity prices share a similar price level with lowest prices observed in Nordpool (41.83€/MWh for base load and 44.43€/MWh peak load periods) and highest mean average prices in France (52.31€/MWh for base load and 63.06€/MWh for peak load periods) during peak as well as base load periods. The high average prices in the French market are not surprising, given that the French electric system is the most inflexible due to its high share of nuclear power in its generation mix as well as widespread electric heating. Unanticipated changes in demand thus lead to pronounced price increases (price spikes). Nordpool, in contrast, is characterised by a large share of hydro units in its production portfolio, which have no variable costs as well as quick ramping times. The maximum values (detailed in row three) for electricity spot prices in Nordpool are therefore the smallest in the sample. Volatility for all markets is substantially larger during peak compared to base load periods, which reflects the convex merit order curve leading to larger price changes within the steeper section.

The carbon prices are quoted in €/EUA. One European Union Allowance (EUA) entitles the holder to emit one ton of CO2. Companies buy and sell permits to emit carbon dioxide under the EU ETS. If companies emit less than their permits allow, they can sell the excessive permits. Carbon prices ranged between 0.01 €/EUA and 29.78 €/EUA with a mean average price of 8.24 €/EUA. Coal prices are reported in €/MWh ranging between 17.81 €/MWh and 58.22 €/MWh and natural gas prices range from 16.90€/MWh to 101.00 €/MWh during the period studied.[2]

[2] Coal prices have been converted from £/ton to €/MWh assuming a heat rate of 35%. Gas prices were originally reported in Pence/Therm and have been converted to €/MWh assuming a heat rate of 50% (EIA, 2014)

Table 1: Summary statistics for coal, carbon, natural gas as well as electricity base and peak prices of all markets under study

	API2 COAL	EU ETS	Natural gas	FR BASE	FR PEAK	GER base	GER peak	NL base	NP base	NP peak	GB BASE	GB PEAK
Mean	29.06	8.89	42.36	52.31	63.06	50.70	60.65	54.10	41.83	44.43	45.28	51.06
Maximum	58.22	29.78	101.00	137.22	226.94	127.08	181.67	191.81	103.93	121.26	143.78	165.06
Minimum	17.81	0.01	16.90	7.11	10.67	5.80	6.76	17.00	7.94	8.46	16.84	18.12
Std. Dev.	7.72	6.86	13.67	17.49	22.94	15.49	20.68	16.41	13.63	14.34	15.61	19.15
observations	1893	2048	2048	2048	2048	2048	2048	2048	2048	2048	2048	2048

6. Empirical Results

6.1. Tests for integration and fractional integration

The *p-values* of the Phillips and Perron (1988) (PP) and Augmented Dickey Fuller (ADF) unit root test are reported in rows two to five of Table 2 for the time series and its first difference. The optimal lag lengths *l* used in the tests are reported in brackets behind the test statistics. The tests for the series strongly reject the hypothesis of a unit root for all electricity base and peak load as well as natural gas prices. The coal and carbon price series on the other hand are characterised by non-stationary behaviour as the *p-value* is larger than .05. The ADF and PP unit root tests on the differenced series strongly reject the unit root hypothesis for all series. It can be concluded that carbon and coal prices are integrated of order one (*I(1)*).

The semi-parametric GPH (Geweke and Porter- Hudak, 1983) estimates for the order of integration *d*_GPH in row six of Table 2 confirms non-stationary *I(1)* behaviour of carbon and coal because the estimates of *ds* are close to 1. The estimated order of integration *d*_2 step ELW, which can be found in row seven of Table 2 is similar to the values obtained via the GPH estimator, thus confirming that carbon and coal prices are non-stationary, integrated *I(1)* process. All electricity spot price series, on the other hand, appear to be fractionally integrated process with quicker speeds of mean reversion because the order of integration *d* is significantly smaller than one. Furthermore, lower values of *d* for peak load compared to base load periods are observed.

Table 2: Assessments of long run dynamics for coal, carbon, natural gas as well as electricity base and peak prices for all markets under study.

	API2 COAL	EU ETS	Natural gas	FR BASE	FR PEAK	GER base	GER peak	NL base	NP base	NP peak	GB BASE	GB PEAK
PP level	0.389*	0.2209*	0.007	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PP first differences	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.001	0.001
ADF level	0.2687 (*l*=9)*	0.2192 (*l* = 1)*	0.0006 (*l* = 0)	0.000 (*l* =3)	0.000 (*l* =8)	0.000 (*l* =3)	0.001 (*l* =13)	0.000 (*l* =4)	0.040 (*l* =9)	0.001 (*l* =9)	0.0203 (*l* = 10)	0.0025 (*l* = 9)
ADF first differences	0.000 (*l*=8)	0.000 (*l* =0)	0.000 (*l* =0)	0.000 (*l* =12)	0.000 (*l* =12)	0.000 (*l* =12)	0.000 (*l* =12)	0.000 (*l* =13)	0.000 (*l* =8)	0.000 (*l* =8)	0.000 (*l* =9)	0.000 (*l* =13)
*d*_GPH	1.009 (0.0247)	1.001 (0.0247)	1.039 (0.0247)	0.6514 (0.0247)	0.6035 (0.0247)	0.6168 (0.0247)	0.5896 (0.0247)	0.6754 (0.0247)	0.8956 (0.0247)	0.8421 (0.0247)	0.658 (0.0247)	0.6064 (0.0247)
*d*_ 2 step ELW	1.25983	0.87970	1.14830	0.6511	0.6525	0.60981	0.6074	0.6227	0.8385	0.7565	0.77872	0.77614
observations	1893	2048	2048	2048	2048	2048	2048	2048	2048	2048	2048	2048

PP refers to Phillips Perron unit root test ADF refers to the Augmented Dicker Fuller test, l is the lag length that has been chosen to carry out the ADF test based on the Akaike Information Criteria. The ADF test has been conducted including an intercept. d_GPH is the Geweke and Porter-Hudak (1983) order of integration estimator and d_2 step ELW the two step exact local whittle estimator (Shimotsu and Phillips, 2005). * indicate 5% significance level.

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6.2. Localized Autocorrelation Functions (LACF) and non-stationarity

Figures 3 to 8 depict the LACF of lags one to 20 for the markets APX-UK, EPEX-FR and Nordpool during base and peak load periods between December 2005 and October 2013. When comparing LACF estimates during peak and base load periods (for example for APX-UK depicted in Figure 3 and 4 respectively), we observe that values of peak prices have a larger range. Furthermore LACF estimates indicate non-stationary periods for peak as well as base load prices. For example for GB (Figures 3 and 4) between the end of November 2006 until end of May 2007 (on the x-axis 200 to 400) LACF values are close to one. But, there may also be stationary periods, where the LACF decline quickly implying decreasing associations between lags. A similar observation holds true for France (Figures 5 and 6), though there seems to be fewer non-stationary periods compared to the Brittish market. The Nordpool LACFs in Figure 7 (base load prices) and Figure 8 (peak load prices) seem to have increased in variance over time. At the beginning of the time series of Nordpool (both base load and peak load prices) the LACF values were high (close to one) and showed little variability. From the second quarter in 2008 (700 on the x-axis) variability seems to have increased.

Figure 5: LACF APX-UK base

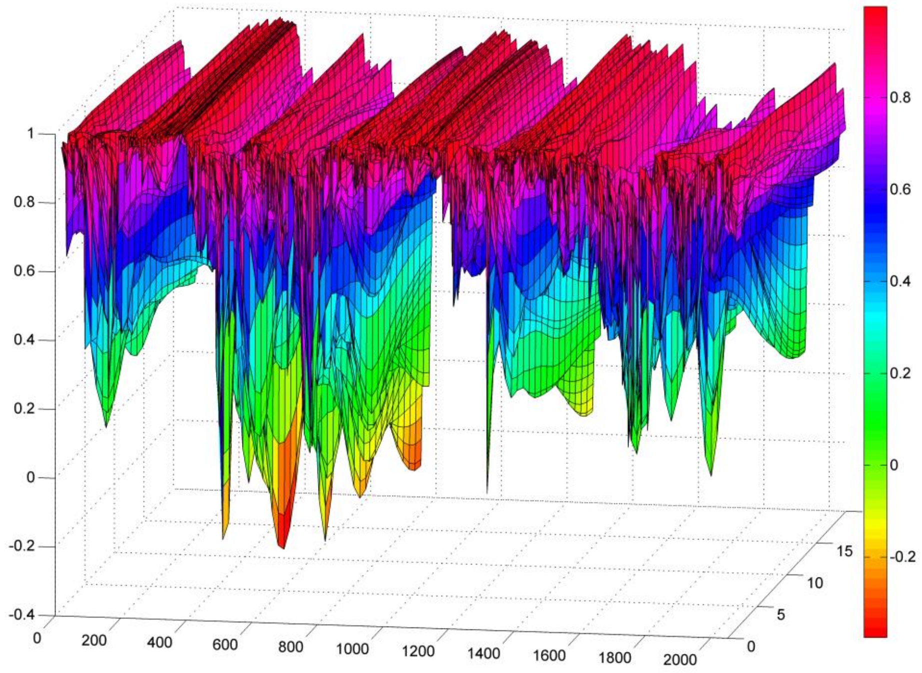


Figure 6: LACF APX-UK peak

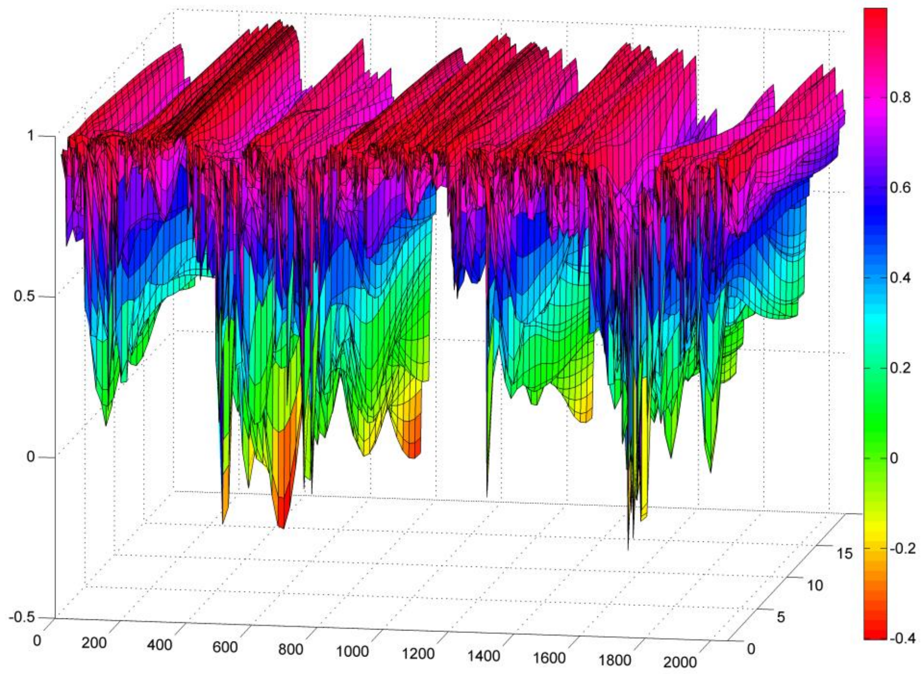


Figure 7: LACF EPEX-FR base

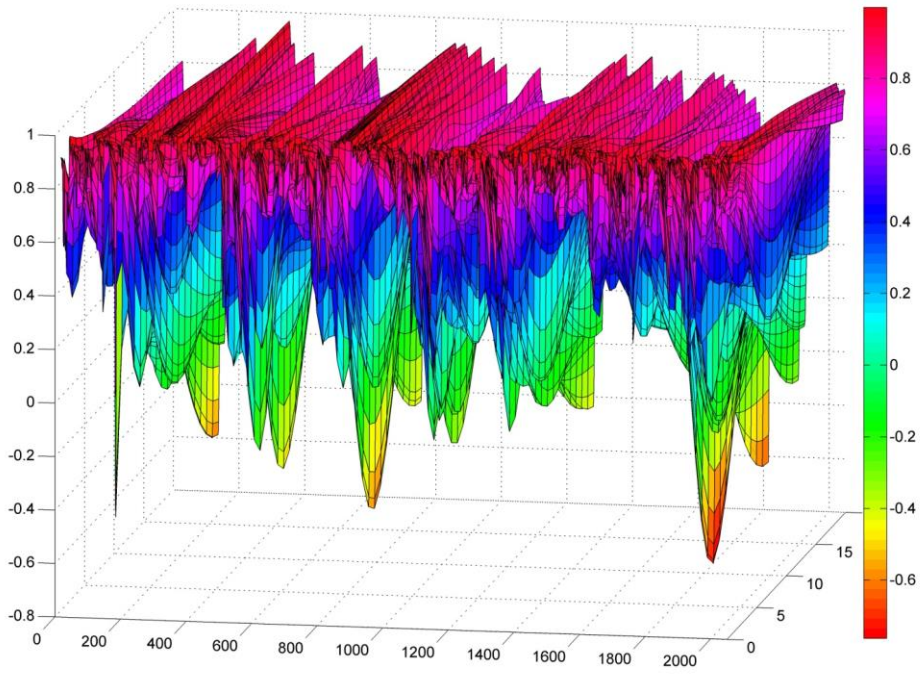


Figure 8: LACF EPEX-FR peak

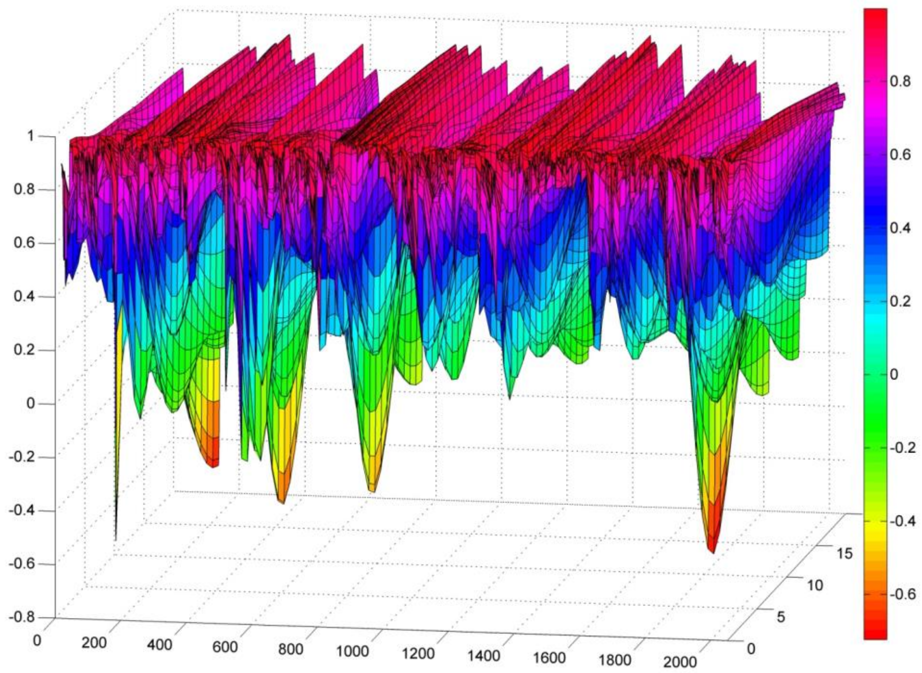


Figure 9: LACF Nordpool base

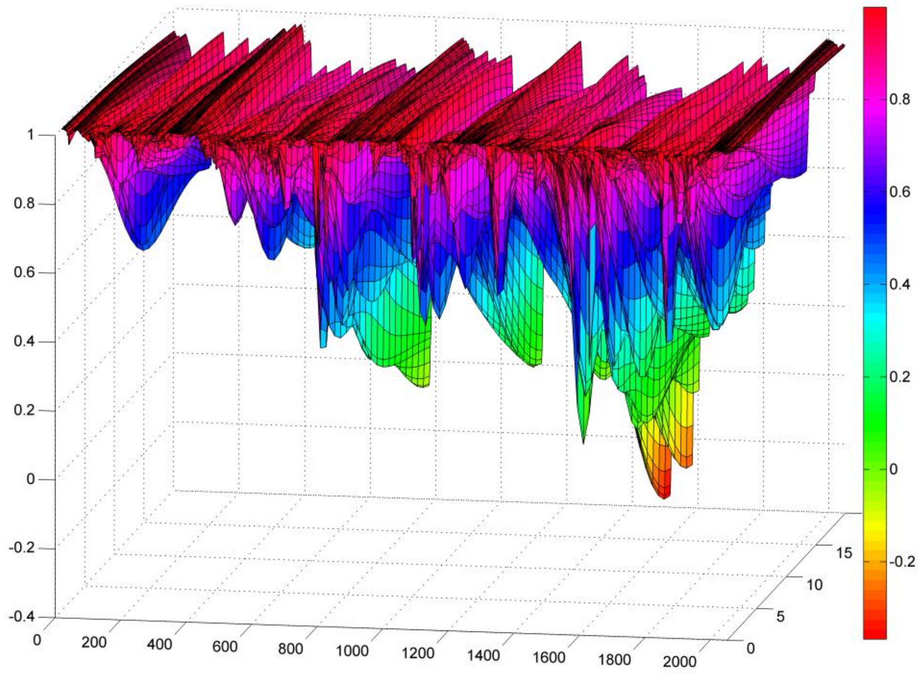
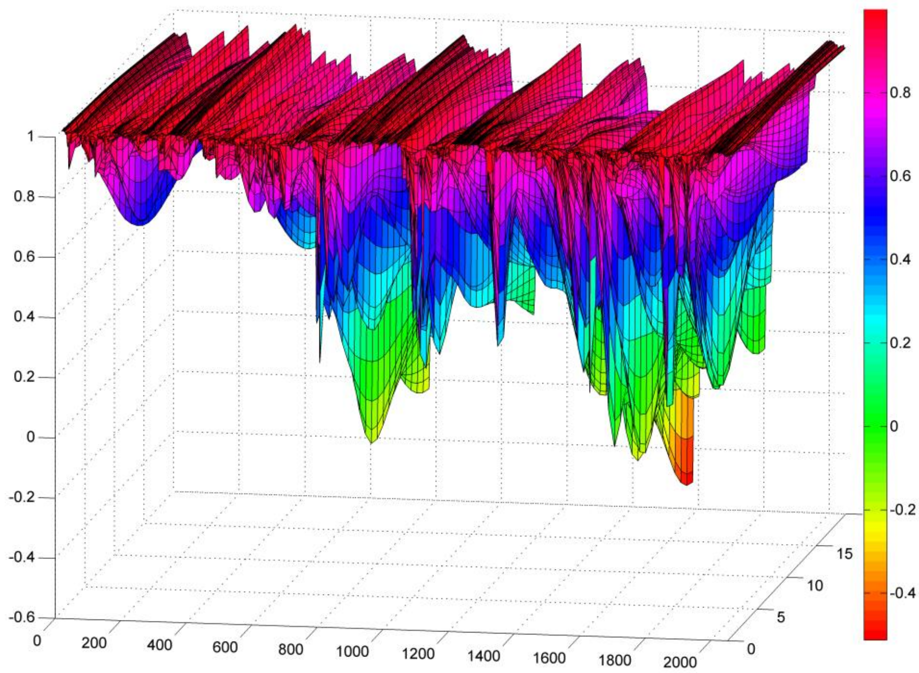


Figure 10: LACF Nordpool peak



According to the identification criteria based on the LACF values, there are 10 periods for British base load electricity spot prices that are likely to be non-stationary. The periods and their duration are listed in Table 3 in the first and second column, respectively. The test results suggest that four of the ten identified non-stationary periods of British base load prices are indeed non-stationary. For six periods the null hypothesis of a unit root was rejected at 5% significance level. For the four periods for which a unit root was confirmed, the ADF test was also conducted for coal, carbon natural gas prices as well as Dutch and French base load electricity prices. The unit root test results are reported in column four to eight. Coal prices and carbon prices were found to be non-stationary during the same four periods as British base load prices. Natural gas prices shared non-stationarity with British base load prices during two periods. Electricity base load prices in The Netherlands were non-stationary during the first period. The French electricity market did not share any non-stationary periods. For the periods where the other variables shared a unit root with British base load prices, a cointergation analysis was carried out which will be detailed in 6.2.

For British electricity peak load prices nine possible non-stationary periods were identified according to the LACF criteria. They are listed in the first column of Table 4. The periods are similar to British electricity base load periods but shorter (first and second column). The null hypothesis of a unit root was rejected at 5% significance level for six periods. For three periods the hypothesis of a unit root could not be rejected. British base and peak load prices mainly contained a unit root during winter and spring months. The other time series (coal, natural gas, carbon, Dutch and French electricity) were assessed for a unit root during the same periods for which a unit root in British electricity peak load prices was confirmed. Results are reported in column four to eight of Table 4. Coal and carbon prices shared non-stationary behaviour during the same three periods. French electricity spot prices were non-stationary only during the first period in Autum 2006, and natural gas was non-stationary during the last period in the first quarter of 2010.

Table 3: British base load prices periods of high persistence and unit root tests

	GB base		EU ETS	Natural gas	API2 coal	FR base	NL base
Period	Number of days	ADF	ADF	ADF	ADF	ADF	ADF
26.09.2006-08.11.2006	**32**	**-0.978 (*l*=1)**	**0.573 (0)**	3.137 (*l*=1)*	**-1.445 (0)**	-2.822 (0)*	**-1.145 (2)**
28.11.2006-31.05.2007	**133**	**-2.026(*l*=6)**	**-1.691 (4)**	-3.081 (*l*=0)*	**-2.371 (0)**	-4.523(0) *	-5.181 (0)*
11.03.2009-19.05.2009	**50**	**-1.994(*l*=5)**	**--1.100 (0)**	**-1.253 (*l*=0)**	**-1.337 (0)**	-3.978 (0)*	-3.701 (0)*
08.07.2009-13.08.2009	27	-3.087(***l***=6)*	-	-	-	-	-
17.08.2009-14.12.2009	86	-3.961(***l***=5)*	-	-	-	-	-
21.12.2009-14.5.2010	**105**	**-2.194(*l*=4)**	**-0.345 (0)**	**-0.585 (*0*)**	**-0.345 (0)**	-3.922 (0)*	-4.448 (0)*
18.01.2011-24.02.2011	28	-4.1201(***l***=1)*	-	-	-		
11.03.2011-28.04.2011	35	-4.165 (***l***=0)*	-	-	-		
02.05.2011-04.08.2011	69	-3.8178(***l***=1)*	-	-	-		
02.05.2011-04.08.2011	69	-3.8178(***l***=1)*	-	-	-		

Periods of high persistence in the LACF for British base load prices. Augmented Dickey Fuller test with intercept and lag l selected with AIC for adjacent energy markets. H0: series has a unit root. * indicate rejection at 5%.Test statistics that indicate that the series contains a unit root are printed in bold.

Table 4: British peak load prices periods of high persistence and unit root tests

	GB peak		Natural gas	API2 Coal	EU ETS	FR peak
Period	Number of days	ADF	ADF	ADF	ADF	ADF
29.09.2006-07.11.2006	**28**	**-1.533(*l*=1)**	-1.882 (*l*=0)*	**-0.895 (*l*=0)**	**0.930 (*l*=0)**	**-0.012 (*l*=1)**
29.11.2006-31.05.2007	**132**	-2.827(*l*=6)*	-3.087 (***l***=0)*	**-2.247 (*l*=0)**	**-2.357 (*l*=5)**	-4.726 (*l*=0)*
11.03.2009-13.05.2009	42	-5.09(*l*=0)*	-	-	-	-
08.07.2009-02.09.2009	41	-3.699(***l***=0)*	-	-	-	-
04.09.2009-14.12.2009	72	-5.782(***l***=0)*	-	-	-	-
19.01.2010-14.05.2010	**84**	**-2.031(*l*=4)**	**-0.763 (*l*=2)**	**0.590 (*l*=0)**	**0.030 (*l*=0)**	-2.820 (*l*=0)*
21.01.2011-18.02.2011	21	-4.512*(***l***=1)	-	-	-	-
09.05.2011-03.06.2011	20	-4.845*(***l***=0)	-	-	-	-
13.06.2011-21.07.2011	29	-3.913*(***l***=0)	-	-	-	-

Periods of high persistence in the LACF for British peak load prices. Augmented Dickey Fuller test with intercept and lag *l* selected with AIC for adjacent energy markets. H0: series has a unit root* indicate rejection at 5%. Test statistics that indicate that the series contains a unit root are printed in bold.

For Nordpool electricity base and peak load prices, eight potentially non-stationary periods were identified by means of the LACF criteria in each case. The periods are listed in the first column in Table 5 and 7, respectively. The length of the potentially non-stationary periods range between 20 to 197 days for base load and 23 to 121 day for peak load prices as detailled in the second columns. The ADF test statistics in the third columns show that four base load and three peak load periods were found to contain a unit root according to the ADF statistics. There appears to be no clear pattern regarding seasons and non-stationarity of Nordpool base load prices as previously evident in the British market.

Natural gas prices show non-stationary behavior during the same four periods as Nordpool base load prices. Coal prices are non-stationary only during one (the last) period from 15.06.2010 to 26.07.2010. Carbon prices show non-stationary behavior during three periods from 12.12.2005 to 6.3.2006 as well as from 29.10.2009 to 25.11.2009 and 15.06.2010 to 26.07.2010. The interconnected German and Dutch electricity markets contain a unit root between July and September 2008 (31.07.2008- 02.09.2008). The periods that have been found to be non-stationary for peak load prices are dissimilar to the identified electricity base load periods (the first non-stationary period is from 08.11.2006 to 24.01.2007; the second non-stationary period is between 31.07.2008 and 29.08.2008 and the third between 16.06.2010 and 27.07.2010). Natural gas is non-stationary during the same period as electricity peak load prices in Nordpool. Coal and carbon prices share non-stationary behaviour during two periods and Germany is non-stationary at the same time with Nordpool electricity peak prices only once (the second non-stationary period).

Table 5: Nordpool base load prices periods of high persistence and unit root tests

	Nordpool base		Natural gas	API2 Coal	EU ETS	NL Base	GER Base
Period	Number of days	ADF	ADF	ADF	ADF	ADF	ADF
12.12.2005-06.03.2006	61	**-0.075 (*l*=3)**	**-0.759 (*l*=0)**	No obs.	**-0.936 (*l*=0)**	-3.854 (*l*=0)*	-2.982 (*l*=0)*
13.11.2006-19.07.2007	197	-2.696 (*l*=1)*	-	-	-	-	-
31.07.2008-02.09.2008	24	**0.821 (*l*=2)**	**-0.766 (*l*=0)**	-6.377 (*l*=0)*	Near unity	**-0.969 (*l*=0)**	**-0.557 (*l*=0)**
04.02.2009-17.07.2009	118	-4.045 (*l*=0)*	-	-	-	-	-
29.10.2009-25.11.2009	20	**-1.216 (*l*=0)**	**-0.760 (*l*=0)**	-3.174 (*l*=0)*	**-0.778 (*l*=0)**	-2.808 (*l*=0)*	-0.989 (*l*=2)*
15.06.2010-26.07.2010	30	**-1.614 (*l*=0)**	**-1.614 (*l*=0)**	-1.128 (*l*=0)	**-0.777 (*l*=0)**	-3.262 (*l*=0)*	-2.584 (*l*=0)*
11.02.2013-11.03.2013	21	-3.053 (*l*=0)*	-	-	-	-	-
14.05.2013-15.10.2013	111	-2.924 (*l*=0)*	-	-	-	-	-

Periods of high persistence in the LACF of Nordpool base load periods. Augmented Dickey Fuller test with intercept and lag l selected with AIC for periods of non-stationarity in Nordpool and energy markets. H0: series has a unit root. * indicate rejection at 5%. Test statistics that indicate that the series contains a unit root are printed in bold.

Table 6: Nordpool peak load prices periods of high persistence and unit root tests

	Nordpool peak		Natural gas	API2 Coal	EU ETS	Ger Peak
Period	Number of days	ADF	ADF	ADF	ADF	ADF
12.12.2005-06.03.2006	61	-3.096 (*l*=0)*	-	-	-	-
08.11.2006-24.01.2007	56	**-1.966 (*l*=0)**	**-0.988 (*l*=0)**	-2.303 (*l*=1)*	**-0.220 (*l*=5)**	-3.909 (*l*=0)**
16.02.2007-18.07.2007	109	-3.268 (*l*=0)*	-	-	-	-
31.07.2008-29.08.2008	22	**0.463 (*l*=2)**	**-1.617 (*l*=0)**	**-0.685 (*l*=0)**	Near unity	**0.189 (*l*=1)**
03.02.2009-21.07.2009	121	-4.089 (*l*=0)*	-	-	-	-
16.06.2010-27.07.2010	30	**-1.858 (*l*=0)**	**-1.858 (*l*=0)**	**-0.924 (*l*=0)**	**-0.693 (*l*=0)**	-3.035 (*l*=0)*
11.05.2011-10.06.2011	23	-3.489(*l*=0) *	-	-	-	-
15.05.2013-15.10.2013	110	-3.309(*l*=0)*	-	-	-	-

Periods of high persistence in the LACF of Nordpool peak load periods. Augmented Dickey Fuller test with intercept and lag selected with AIC for periods of non-stationarity in Nordpool and energy markets. H0: series has a unit root* indicate rejection at 5%. Test statistics that indicate that the series contains a unit root are printed in bold.

For French electricity base load prices two non-stationary periods lasting 68 and 70 days from February to May in 2007 and in 2009 are reported in the first column of Table 7. However, only natural gas shared non-stationary behaviour during the first period. For French peak load prices four non-stationary periods could be established, but the ADF test statistics reported in the third column of Table 8 reject the null hypothesis of a unit root in three instances. For the last period from 17.06.- 09.08.2011 a unit root was confirmed for all variables (natural gas, coal and carbon prices, British and German electricity peak load prices).

Table 7: FR base load prices periods of high persistence and unit root tests

	FR base		Natural gas	API2 Coal	EU ETS	GB	GER
Period	Number of days	ADF	ADF	ADF	ADF	ADF	
07.02.2007-11.05.2007	68	**-1.809 (*l*=5)**	**-2.052 (*l*=0)**	-4.236(***l***=0)*	-5.618 (***l***=0)*	-4.236(***l***=0)*	-5.618(***l***=0)*
16.02.2009- 22.05.2009	70	**1.445 (*l*=5)**	-3.807 (***l***=0) *	-5.491 (***l***=0)*	-5.506 (***l***=0)*	-2.539 (***l***=0)*	-5.506(***l***=0)*

Periods of high persistence in the LACF. Augmented Dickey Fuller test with intercept and lag *l* selected with AIC for non-stationary periods in France and energy markets. H0: series has a unit root* indicate rejection at 5%. Test statistics that indicate that the series contains a unit root are printed in bold.

Table 8: FR peak load prices periods of high persistence and unit root tests

	FR peak		Natural gas	API2 Coal	EU ETS	GB	GER
Period	Number of days	ADF	ADF	ADF	ADF	ADF	
16.02.2009 15.04.2009	43	-3.367 (***l***=0)*	-	-	-	-	-
20.04.2009-26.05.2009	27	-4.861 (***l***=0)*	-	-	-	-	-
16.02.2011-05.04.2011	35	-3.940 (***l***=0)*	-	-	-	-	
17.06.2011-09.08.2011	38	**-1.385 (*l*=1)**	**0.031 (*l*=0)**	**-1.605 (*l*=0)**	**-2.429 (*l*=0)**	**-1.385 (*l*=1)**	**-1.417 (*l*=1)**

Periods of high persistence in the LACF. Augmented Dickey Fuller test with intercept and lag l selected with AIC for electricity markets that neighbour France during base periods. H0: series has a unit root.* indicate rejection at 5%. Test statistics that indicate that the series contains a unit root are printed in bold.

All in all, there is evidence to show that EU electricity spot prices are locally stationary processes as they show periods of non-stationarity in their price dynamics as well as periods where prices revert to their mean more quickly. In the following section we assess convergence during the identified non-stationary periods.

6.2. *Analysis of convergence*

The time-varying LACF estimates and the rejection of the unit root hypothesis for the electricity prices using the whole sample suggest that cointegration analysis is not applicable to the time series as it requires the data to contain a unit root. Only the identified non-stationary periods are investigated concerning common long run dynamics in the analysis as is detailed in the following.

6.2.1. GB

The cointegration analysis for British electricity base load and peak load prices are summarised in Table 9 and 10, respectively. The periods that have been found to contain a unit root in the previous section are listed in the first columns. The second column lists the variables for which cointegration is assessed as a unit root for the respective period was also confirmed previously. The third colum contains the null hypothesis, which is no cointegration. The and Maximum Eigenvalue (λ_{eigen}**)** and Trace (λ_{trace}) test statistics are stated in columns four and five, repectively and *p-values* are reported in brackets behind.

For British electricity prices four cointegrating relationships for base prices (Table 9) and three for peak load periods (Table 10) were found. For the first period in autumn 2006 (26.09.2006 to 08.11.2006) carbon prices are integrated with British electricity base load prices according to the Maximum Eigenvalue statistics (5% significance level). The λ_{eigen} test statistics surpass their critical values and we reject the hypothesis *not integrated*. Cointegration with coal, and Dutch electricity base load prices was rejected.

In the second non-stationary period (row five and six) there is also an association between carbon and British base load prices during the winter months 2006/2007 (28.11.2006 to 31.05.2007). Despite non-stationary behaviour of British electricity base load prices for the third period (11.03.2009 to 19.05.2009), we do not find co-movement with any other variable under study.

During the last non-stationary period lasting from December 2009 to late spring 2010 (21.12.2009-14.5.2010) the Trace as well as the Maximum Eigenvalue statistics suggest cointegration between natural gas and British electricity base load prices as the test statistics is larger than the critical value. Furthermore, the two statistics suggest cointegration between British electricity base load prices and coal prices.

Table 9: British Base Load Prices: Cointegration analysis during non-stationary periods with other markets, fuel and carbon prices.

Period	**Variable**	**Hypothesis**	λ_{trace}	λ_{eigen}
26.09.2006-08.11.2006	API2 Coal	Not cointegrated	2.930 (0.970)	2.925 (0.952)
	EU ETS	Not cointegrated	14.964 (0.060)	14.881 (0.040*)
	NL Base	Not cointegrated	8.174 (0.447)	6.940 (0.447)
28.11.2006-31.05.2007	API2 Coal	Not cointegrated	12.277 (0.144)	9.939 (0.216)
	EU ETS	Not cointegrated	18.070 (0.020*)	14.504 (0.046*)
11.03.2009-19.05.2009	Natural gas	Not cointegrated	7.485 (0.522)	0.128 (0.592)
	API2 Coal	Not cointegrated	12.404 (0.139)	9.614 (0.239)
	EU ETS	Not cointegrated	2.863 (0.973)	2.815 (0.958)
21.12.2009-14.5.2010	**Natural gas**	Not cointegrated	17.814 (0.022*)	14.048 (0.054)
	API2 Coal	Not cointegrated	26.668 (0.001*)	26.140 (0.000*)
	EU ETS	Not cointegrated	7.346 (0.538)	7.237 (0.462)

Cointegration test for British base load prices for non-stationary periods with other markets, fuel and carbon prices. * denote 5% significance.

For British electricity peak load periods results are reported in Table 10. Just as for base load prices for the first non-stationary period during autumn 2006 (29.09.2006- 07.11.2006), British electricity peak load prices and carbon prices are cointegrated according to the Maximum Eigenvalue statistic at 5% significance level. British electricity peak load prices also moved with carbon prices between the end of November 2006 to end of May 2007. The last non-stationary period of British peak load prices coincides with the fourth non-stationary period of British base load prices but is significantly shorter. British peak load prices and coal, as well as British peak load prices and carbon prices, were found to be cointegrated.

All in all, British peak load prices were found to be integrated with the same variables as British electricity base load prices, but for shorter periods. The British electricity market did not show any signs of convergence with interconnected electricity markets.

Table 10: British Peak Load Prices: Cointegration analysis during non-stationary periods with other markets, fuel and carbon prices

Period	Variable	Hypothesis	λ_{trace}	λ_{eigen}
29.09.2006-07.11.2006	API2 Coal	Not cointegrated	2.930 (0.970)	2.925 (0.952)
	EU ETS	Not cointegrated	14.964 (0.060)	14.881 (0.040*)
	FR Peak	Not cointegrated	8.174 (0.447)	6.940 (0.447)
29.11.2006-31.05.2007	API2 Coal	Not cointegrated	12.277 (0.144)	9.939 (0.216)
	EU ETS	Not cointegrated	18.070 (0.020*)	14.504 (0.046*)
19.01.2010-14.05.2010	Natural gas	Not cointegrated	7.485 (0.522)	0.128 (0.592)
	API2 Coal	Not cointegrated	23.327 (0.003*)	23.299 (0.002*)
	EU ETS	Not cointegrated	16.141 (0.040*)	16.041 (0.026*)

Cointegration analysis for British peak load prices for non-stationary periods with other markets, fuel and carbon * denote 5% significance.

6.2.2. Nordpool

Table 11 presents the four non-stationary periods (first column) and cointegration test statistics (column four and five) for Nordpool electricity base load prices with the variables (listed in 2nd column) which also contain a unit root in the respective period. The results of the cointegration analysis using the Trace and Maximum Eigenvalue test statistics confirm only one of ten possible cointegrating relationships for Nordpool base load prices. Between the end of July and the beginning of September 2008 (31.07.2008- 02.09.2008), German electricity base load prices appear to be integrated with Nordpool electricity base load prices at 5% significance level according to both test statistics. The Dutch electricity prices series during the same period did not share a cointegrating relationship with Nordpool base load prices.

For Nordpool peak load periods (Table 12) a cointegrating relationship was confirmed only with German peak load prices at 5% significance level according to the Trace as well as the Maximum Eigenvalue statistics. The period is similar to base load prices from 31.07.2008-29.08.2008. For all other variables we reject the hypothesis of cointegrating relationships with Nordpool peak prices.

We do not find associations between the Nordpool electricity market and any fuel or carbon prices.

Table 11: Nordpool Base Load Prices: Cointegration analysis during non-stationary periods with other markets, fuel and carbon prices

Period	**Variable**	**Hypothesis**	λ_{trace}	λ_{eigen}
12.12.2005-06.03.2006	Natural gas	Not cointegrated	13.497 (0.098)	13.413 (0.068)
	EUETS	Not cointegrated	4.447 (0.864)	3.817 (0.878)
31.07.2008-02.09.2008	Natural gas	Not cointegrated	6.999 (0.578)	5.459 (0.683)
	NL Base	Not cointegrated	13.061 (0.113)	11.900 (0.115)
	Ger Base	Not cointegrated	18.301 (0.018*)	17.762 (0.013*)
29.10.2009-25.11.2009	Natural gas	Not cointegrated	4.460 (0.863)	4.456 (0.808)
	EUETS	Not cointegrated	4.706 (0.839)	3.666 (0.893)
15.06.2010-26.07.2010	Natural gas	Not cointegrated	6.563 (0.629)	5.503 (0.677)
	EUETS	Not cointegrated	4.128 (0.893)	4.084 (0.850)
	API 2 Coal	Not cointegrated	4.774 (0.832)	3.196 (0.933)

Cointegration analysis for Nordpool base load prices for non-stationary periods with other markets, fuel and carbon prices. * denote 5% significance.

Table 12: Nordpool Peak Load Prices: Cointegration Analysis during non-stationary periods with other markets, fuel and carbon prices

Period	**Variable**	**Hypothesis**	λ_{trace}	λ_{eigen}
08.11.2006-24.01.2007	Natural gas	Not cointegrated	6.950 (0.584)	5.289 (0.705)
	EU ETS	Not cointegrated	10.345 (0.255)	5.534 (0.673)
31.07.2008-29.08.2008	Natural gas	Not cointegrated	5.210 (0.786)	5.202 (0.716)
	API2 Coal	Not cointegrated	9.654 (0.308)	9.222 (0.268)
	Ger Peak	Not cointegrated	18.641 (0.016*)	18.640 (0.010*)
16.06.2010-27.07.2010	Natural gas	Not cointegrated	8.700 (0.394)	8.223 (0.356)
	API2 Coal	Not cointegrated	3.332 (0.950)	2.504 (0.974)
	EU ETS	Not cointegrated	4.458 (0.863)	4.211 (0.837)

Cointegration analysis for Nordpool peak prices for non-stationary periods with other markets, fuel and carbon prices. * denote 5% significance.

6.2.3. France

For the French electricity base load prices non-stationary behavior was confirmed for only one period between 07.02.2007 and 11.05.2007, listed in the left column of Table 13. Natural gas was the only variable which was also found to be non-stationary during that period and we found strong evidence for cointegration for the pair according to the Trace as well as Maximum Eigenvalue Statistics.

For French electricity peak prices, the period from 17.06.2011 to 09.08.2011 was assessed regarding convergence with other electricity markets, fuel or carbon prices. Columns four and five of Table 14 contain the test results of the Trace and Maximum Eigenvalue statistics for French peak load periods with natural gas, coal and carbon prices and adjacent electricity markets GB and Germany. For the single period which was found to be non-stationary cointegration of French peak load prices with fuel and carbon prices was rejected. The hypothesis of no cointegration with German and British electricity peak prices on the other hand was rejected at 5% significance level using the Trace test statistics.

Table 13: EPEX-FR Base Load Prices: Cointegration analysis during non-stationary periods with other markets, fuel and carbon prices

Period	**Variable**	**Hypothesis**	λ_{trace}	λ_{eigen}
07.02.2007-11.05.2007	**Natural gas**	Not cointegrated	24.907 (0.0014*)	23.129 (0.0016*)

Cointegration analysis for French base load prices for non-stationary periods with other markets, fuel and carbon prices. * denote 5% significance.

Table 14: EPEX-FR Peak Load Prices: Cointegration analysis during non-stationary periods with other markets, fuel and carbon prices

Period	**Variable**	**Hypothesis**	λ_{trace}	λ_{eigen}
17.06.2011- 09.08.2011	Natural Gas	Not cointegrated	11.421 (0.1869)	11.3808 (0.1361)
	API2 Coal	Not cointegrated	9.2627 (0.3417)	7.6474 (0.4157)
	EU ETS	Not cointegrated	12.561 (0.1319)	9.9515 (0.2151)
	GB peak	Not cointegrated	15.965 (0.0425*)	13.739 (0.0604)
	GER peak	Not cointegrated	16.053 (0.0412*)	14.0155 (0.0547)

Cointegration analysis for French peak load prices for non-stationary periods with other markets, fuel and carbon prices. * denote 5% significance.

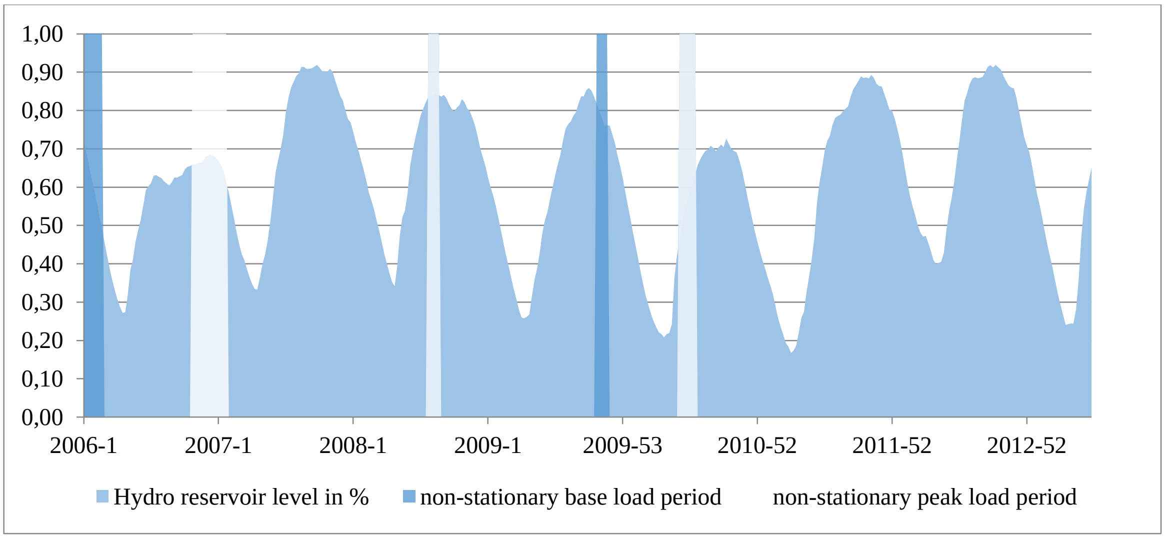
7. Discussion

In the first part of the analysis, the time series of electricity spot prices were examined and the order of integration of each time series was assessed. Whilst electricity spot and natural gas prices are found to be fractionally integrated stationary processes, coal and carbon prices are characterised by non-stationarity (integrated of order *I(1)*). The LACF estimates showed that electricity spot prices in the three markets (GB, Nordpool and France) have changing price dynamics. Periods that appeared highly persistent in its LACF were tested for a unit root. The results revealed, that some of the periods were indeed non-stationary. For electricity peak and base load prices, periods are similar in the three markets. Nonetheless, the unit root test did not confirm non-stationarity for all periods that were identified with the identification criteria. The method could therefore be scrutinised with a rolling window ADF test, with varying window sizes to compare the results.

Fewer non-stationary peak load periods are identified which are generally shorter in comparison to base-load prices. This finding is consistent with the higher estimate for the order of integration *d* observed in the base compared to peak load periods, thus indicating slower mean reversion of base load prices.

In the British market a seasonal pattern could be identified: non-stationarity mainly occurred during winter and spring months, periods with high heating demand. The estimates of LACF in Nordpool showed a break in its behaviour apparently due to the commissioning of the NorNed Interconnector in May 2008 which physically linked Norway with the central European market for electricity. LACF values before the commissioning of the NorNed interconnector showed less variability and values closer to 1. LACF values thereafter were much less persistent. Unit root tests in Nordpool revealed that after 2009 non-stationary periods coincided with high hydro reservoir levels, as illustrated by Figure 8. Prices during these periods are more resilient against demand or supply shocks due to avaliability of highly responsive hydro powered plants. The least number of non-stationary periods was identified for the French market.

Figure 11: Hydro reservoir level for Nordpool and non-stationary periods

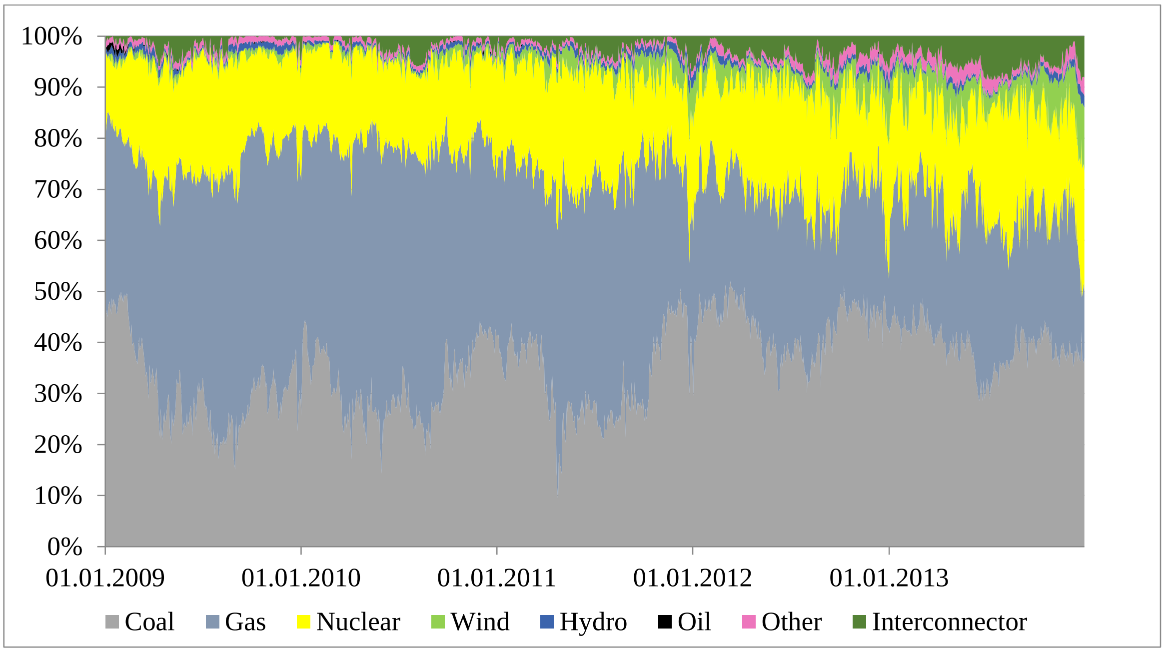


Hydro reservoir level for Nordpool and non-stationary base and peak load periods from January 2006 to June 2013 [Source: NordpoolSpot, 2014]

Cointegration tests were then used to assess co-movement with natural gas, coal and carbon prices as well as with other interconnected or coupled electricity spot markets during the identified non-stationary periods. The results show that electricity spot price movements in the different markets are influenced by the electricity mix and cross border trade. Spot prices in the British market, which are characterised by a high share of natural gas in its electricity mix, are found to be more associated with carbon, natural gas and coal prices. The British electricity market is also characterised by a comparably small volume of cross-border trade indicating less integration with continental European electricity markets: in 2013 only 8.57TWh of electricity was traded through APX-UK compared to more than 40 times this amount in Nordpool (349TW h) and almost 7 times in EPEX-FR (59.3TWh (value for 2012)) (APX-UK, 2013; NordPoolSpot, 2013; EPEX, 2012). Not surprisingly British electricity spot prices were found to be independent from interconnected markets.

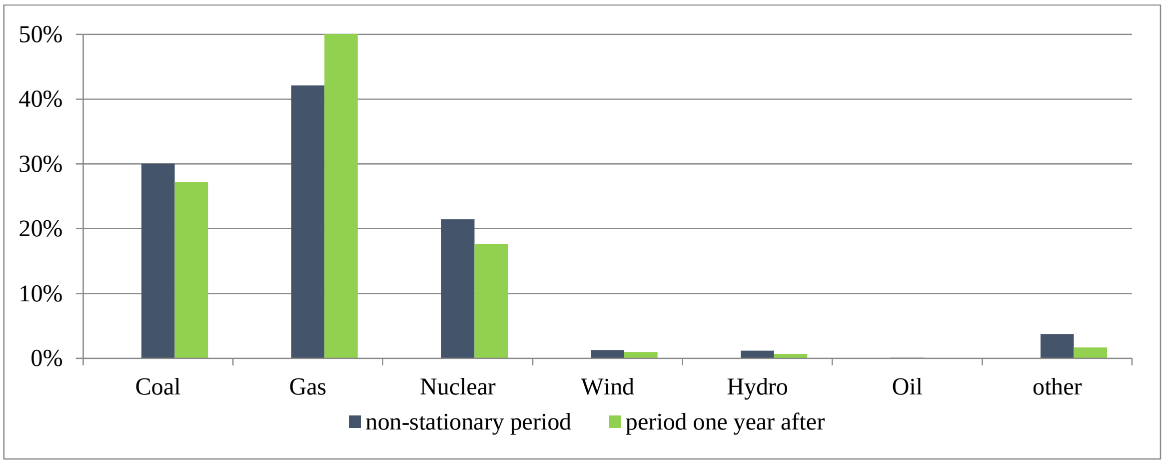
Figure 10 illustrates the changing electricity mix in GB between 2009 and 2013, which has also been used to create Figure 11 and 12. The two Figures display the comparison of the British electricity mix during the non-stationary period and the British electricity mix during the same period one year after and one year before. For both periods where convergence of electricity and natural gas prices were found, the share of natural gas in the electricity mix was higher than in the other periods. Additionally, extreme meteorological conditions in GB during that period were reported. In the first quarter of 2010, two balancing alerts from the National Grid due to production problems in Norway provoked a brief reduction of gas flow (European Commission, 2010). Electricity prices were therefore soaring in the second quarter of 2010 and strongly associated with its marginal cost of production.

Figure 12: Time-varying electricity mix GB



Weekdaily British electricity generation by fuel and supply by interconnector from 1.1.2009- 31.12.2013 [Source: Elexon]

Figure 13: British fuel mix comparison A



Fuel mix British during the non-stationary period (11.03.2009-19.05.2009), and one year after (11.03.2010-19.05.2010). Own calculation [Source Elexon, 2014**]**

Figure 14: British fuel mix comparison B

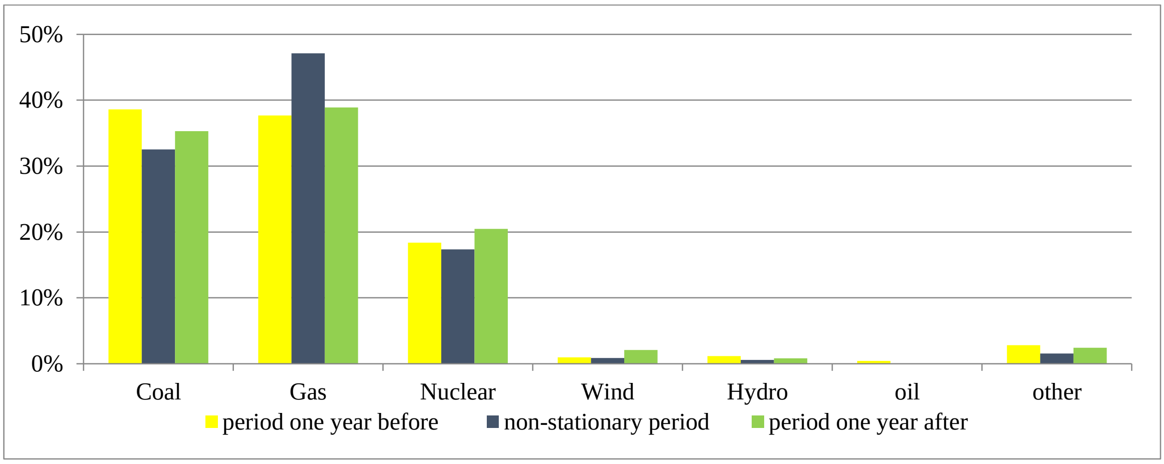


Figure 15: Fuel mix British during the non-stationary period (21.12.2009-14.05.2010), one year before (21.12.2008-14.05.2009) and one year after (21.12.2010- 14.05.2011). Own calculation [Source Elexon, 2014]

The French and the Nordpool electricity markets are characterised by a low share of conventional thermal electricity plants, as detailed in section 3.1. Not surprisingly, we found only one period of common long run dynamics between natural gas and French base load prices. Electricity market integration between France and natural gas price can be explained with a long warm spell from January to August 2007. The hot weather limited nuclear electricity output due to reduced cooling capacity and demanded for alternative sources of electricity generation. Interestingly, in 2011, a similar incident in the 2nd and 3rd quarter decreased availability of nuclear power led to price convergence between France and adjacent electricity markets (GB and Germany) but not with fuel prices (European Commission, 2011a, b). This may indicate that alternative mechanisms are in force making use of electricity market integration to compensate for capacity shortfalls. When assessing integration with adjacent electricity markets we find more noteworthy additions to the existing literature. We cannot support Bosco et al. (2010), who using data until 2007 concluded that Nordpool did not share a common trend with other markets due to individual peculiarities in the technology structure. In the summer of 2008 we found Nordpool to be integrated with the German electricity market during peak and base load periods. All in all, findings might be interpreted as signs for a positive development in the creation of an integrated Pan-European electricity market. Liberalization and market integration may reduce associations between fuel and electricity prices. However for the British market, there are no converging periods with any other electricity market, suggesting that GB is more independent due to its own natural gas resources and only insufficiently linked to the continental electricity market.

8. Conclusion

We contribute to the existing literature by applying a relatively unknown statistic for time series analysis and show that electricity spot prices are locally non-stationary processes with non-stationary, as well as stationary periods. The time varying behavior of electricity spot prices suggest that cointegration analysis may not be an appropriate tool to assess electricity market integration in a time-invariant framework. Furthermore, the aim of integration, which is increasing speeds of mean reversion and the necessary non-stationary behavior to use the method, is conflicting.

Results of the study show that electricity prices are integrated with fuel and carbon prices and other electricity markets during some non-stationary periods. The relevance of the local electricity mix and market integration for such associations was highlighted. Weaker associations with fuel prices were established for the two markets that were well connected to other markets. It can therefore be inferred that fuel price dependency can be reduced, and supply and demand can be managed more flexibly with the integration to other electricity markets. Another implication of the findings is that previous studies may have overestimated the strength of market integration if they omitted common price drivers as a result of a similar electricity mix.

A limitation of this study was caused by the low power of trace and maximum eigenvalue statistics resulting from small sample sizes, which led to some conflicting results. A less restrictive method such as fractional cointegration should therefore be used for future investigations. This would also allow including intermittent renewable energies, which are characterized by mean-reversion.

Another limitation of the study is that the assessment was not conducted for all bordering or interconnected markets, as for some markets (e.g. the Spanish) prices were not available in peak and base load resolution. Furthermore, the use of London Natural Gas as an indicator of natural gas prices as well as API2 coal for coal prices in Europe could be questioned. Other indices are available, which could have led to different results. However, we assume the variation to be marginal due to the liquidity in the natural gas market and the predominance of API2 coal traded.

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