# INTEGRATION OF LIBERALISED EUROPEAN ELECTRICITY MARKETS

MELANIE AJOKE HOULLIER

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**Abstract**

The aim of this thesis is to assess the integration of European electricity markets. An integrated market could help to improve security of supply, foster competition, and may also help to integrate renewables. After reviewing the literature and describing the context, three studies are reported as separate chapters, which besides the common underlying theme use novel econometric and statistical methodology for time series analysis.

Chapter two examines electricity market integration in nine European spot markets between 2000 and 2013, and four forward markets between 2007 and 2012. In contrast to most previous studies, this study proposes that electricity price processes are time-varying, and assesses the potential impacts of special events. Spot prices are found to be fractionally integrated and mean-reverting processes whose parameters are time-dependent and associated with electricity market coupling initiatives or changes in interconnector capacity. Forward prices, in contrast, do not revert to the mean, and in general show more stable common long-run associations than electricity spot prices.

Chapter three investigates the association between electricity market integration, fuel and carbon price developments during base and peak load hours from December 2005 to October 2013 for France, Nordpool and the UK. The local electricity mix and interconnection with adjacent markets are found to be associated with common price dynamics between electricity markets, as well as with electricity fuel and carbon prices.

Chapter four studies the possible implications of Germany's Nuclear Phase Out Act on the integration of EU's electricity market. In 2011, Germany's secure generating capacity decreased significantly after eight nuclear power plants were closed within a period of six months. The short-run interrelationships of electricity spot prices, from November 2009 to October 2012, with wind introduced by the German system, are modelled using multivariate generalised autoregressive conditional heteroscedasticity (MGARCH) models with dynamic correlations. In addition, a time-varying fractional cointegration analysis is conducted to identify any change in mean reversion and convergence of electricity spot prices. The results suggest unintended consequences from the policy: in the one-year period after the closures, the German market decoupled from the other markets and price volatility transmission increased.

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## IV. ABBREVIATIONS

| | |
|---|---|
| ACER | Agency for Cooperation of Energy Regulators |
| ADF | Augmented Dickey Fuller test |
| AGEB | Arbeitsgemeinschaft Energiebilanz |
| AIC | Akaike Information Criteria |
| APX-UK | Anglo-Dutch Power Exchange UK |
| APX-NL | Anglo-Dutch Power Exchange NL |
| BDEW | Bundesverband der Energie- und Wasserwirtschaft |
| Belpex | Belgian Spot Exchange |
| BMU | Bundesministerium für Umwelt |
| BWE | Bundesverband Windenergie |
| CCGT | Combined Cycle Gas Turbine |
| CDD | Cooling Degree Days |
| CO2 | Carbon Dioxide |
| CWE | Central Western European Marker Coupling |
| EDCC | Engle’s Dynamic Conditional Correlation Model |
| EEG | Erneuerbare Energien Gesetz |
| ELW | Exact Local Whittle Estimator |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| EUA | European Union Allowance |
| EPEX-DE | European Power Exchange Germany |
| EPEX-FR | European Power Exchange France |
| EU | European Union |
| EUETS | European Emissions Trading Scheme |
| FELW | Feasible Exact Local Whittle Estimator |
| FR | France |
| GB | Great Britain |
| GER | Germany |

| | |
|---|---|
| GPH | Geweke and Porter- Hudak long memory estimator |
| GWh | Gigawatt hour |
| HDD | Heating Degree Days |
| HP | Hodrick Prescott Filter |
| IPEX | Italian Electricity Exchange |
| JB | Jarque Bera Statistics |
| KPSS | Kwiatkowski–Phillips–Schmidt–Shin unit root test |
| KWh | Kilowatt hour |
| LACF | Localized Autocorrelation Function |
| MGARCH | Multivariate Generalized Autoregressive Conditional Heteroscedasticity Model |
| NL | The Netherlands |
| OFGEM | Office for Gas and Electricity Markets |
| OMEL | Operadora de Mercado Espanol de Electricidad |
| OTE | Czech Power Exchange |
| OTC | Over the counter contracts |
| PP | Phillips Perron test |
| RESA | Renewable Energy Source Act |
| RES-E | Renewable Energy Sources |
| SIC | Schwarz Information Criteria |
| SWISSIX | Swiss Power Exchange |
| TLC | Trilateral Markert Coupling |
| TTDCC | Tse and Tsui’s Dynamic Conditional Correlation Model |
| TWh | Terawatt hour |
| UK | United Kingdom |
| USA | United Sates of America |

## 1. Introduction

The liberalisation of *European* electricity markets is the world's most extensive cross-jurisdictional reform of the electricity sector, and aims to integrate national electricity markets into one common market (Jamasb and Pollit, 2005). Many studies in industrial organisation and international trade recognise that market integration and joint operations are sources of social welfare (e.g. Krugman and Obstfeld, 2009; Markusen, 1981). The benefits of enlarging the geographical scope of electricity markets are, at least in theory, clear: increased *economic efficiency* through economies of scale; *lower prices*, due to greater competition and the substitution of expensive technology with cheaper generation technology (see for instance Emerson et al., 1988; Turvey, 2006); *lower market concentration*; and higher *security of supply* (Creti et al., 2010; Boffa and Scarpa, 2009). Prices in integrated markets are expected to settle between the lowest and the highest prices of the individual markets. Consequently, integration can benefit consumers in high-cost production markets and increase the profitability of lower-cost producers (Finon and Romano, 2009). Moreover, as observed by many authors (e.g. Borenstein and Bushnell, 2000; Shukla and Thampy, 2011), participants in electricity markets are prone to exercise market power, which is the situation in which a company is able to raise the price of a good or service above marginal costs. Increased competition through market integration could reduce this risk, increase liquidity and lead to more stable prices. Within the *European Union*, liberalisation is therefore strongly tied to the general principles of a single internal market rather than separate national markets for goods and services, and was introduced to the electricity sector with the Single Electricity Act of 1986 (Gebhardt and Höffler, 2007). Since then, several directives (e.g. 96/92/EC; 2003/54/EC; 2009/72/EC) have addressed not only how to improve competition in electricity markets, but also specified paths to other common objectives like the integration of renewable energy and security of supply.

Based on estimates published by the Agency for Cooperation of Energy Regulators (ACER, 2013), the Central Western European (CWE) region comprising the Belgian, Dutch, French and German electricity markets has realised significant trade gains from market integration. Compared to separate national markets, more than 250 million euros have been saved annually.

However, it is said that large gains from trade are still left untapped, indicating that market integration may not be completed.[1] Aside from the financial benefits, an integrated European market is expected to reduce dependency on fuel or trade partners, and facilitate energy crisis support between countries. This could potentially increase energy security in all Member States. In order to achieve the European 2020 target of having 20% of its energy from renewable sources, an integrated market could also become a vehicle for addressing the challenge of incorporating highly variable sources of renewable energies, such as photovoltaics or wind, into a more manageable grid (ENTSO-E, 2011). Despite the advantages of an internal EU electricity market, barriers to market integration may still remain. These include the inefficient use of existing transmission networks, a lack of investment in electricity network infrastructure (ACER, 2013), and energy policies with focus on welfare gains within national territories (Böckers et al., 2013).

With 2014 set as a deadline by the EU´s Heads of State for the completion of the internal electricity market, and 2015 as the year by which Europe's '*energy islands*' should be interconnected, the analysis of common dynamics and convergence of electricity prices tops the agenda (ACER, 2011). Divergent long- and short-term electricity price behaviours indicate that structural differences at the national level are still dominant, and that arbitrage opportunities remain limited (Bosco et al., 2010).

The central aim of this PhD thesis is to deepen the understanding of the present policy and academic discussion on electricity price convergence within deregulated European markets, and to address some of the knowledge gaps, including: Which factors drive convergence and divergence? Is market integration changing over time? What is the association between electricity mix and electricity price convergence? And how does a reduction in secure base load capacity impact on electricity market integration?

The thesis is structured as follows: The remainder of chapter one introduces the research by reviewing and assessing the literature on European electricity market integration and setting the contextual background. The main focus is on electricity markets that are examined in the three

[1] Possible trade gains that are not achieved: Italy and France (19 million euros per year), Germany and Sweden (10.5 million euros per year), The Netherlands and Norway (16 million euros per year) (ACER, 2013).

empirical studies (Belgium, Czech Republic, France, Germany, Great Britain (GB), Italy, Scandinavia, Spain and The Netherlands). Chapter one concludes with the research questions to be investigated in the subsequent three chapters. Chapters two to four contain the three papers that addressed the three research questions on electricity market integration in Europe:

"*Reassessing the Integration of European Electricity Markets: A Fractional Cointegration Analysis*";

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

"*Germany's Nuclear Power Plant Closure and the Integration of Electricity Markets in Europe*".

The thesis concludes with chapter five, where the main contributions of the research are summarised, limitations acknowledged and possible future research highlighted.

*1.1. Previous Literature on Electricity Market Integration*

Previous studies on market integration used the Law of One Price as the theoretical foundation to determine whether a geographic region, in which a well-defined product is traded, constitutes a single market. The Law of One Price describes:

> "*an equilibrium relationship that is enforced by arbitrage. The law states that the prices of the same commodity offered in two different markets should never differ by more than the cost of transporting the commodity between the two markets (after adjusting for the exchange rate between the two markets if the prices are denominated in different currencies). Violations of the law of one price can indicate barriers to trade*" (Marshall, 2000).

Boisselau (2004) assessed the Law of One Price for France, Germany, Scandinavia, Spain, The Netherlands and the United Kingdom (UK) in 2002, using hourly electricity spot price data. The author found that most electricity price series were stationary and therefore concluded that the nature of the data did not allow for testing long-run integration using cointegration analysis, which is the most commonly used method to assess convergence. Subsequently, Armstrong and Galli (2005) examined four main electricity bourses in the Eurozone (France, Germany, Spain and The Netherlands) that share common borders and similar price-setting processes, in order to determine whether prices were converging. The authors established that the average price difference decreased between January 2002 and December 2004 in almost all cases, but more so during peak periods of demand. Zachmann (2008) examined a similar time period to Armstrong and Galli's (2005). The author inferred that by mid-2006, market integration had not been attained for eleven European markets (Austria, the Czech Republic, East Denmark, West Denmark, France, Germany, The Netherlands, Poland, Spain, Sweden and the UK). Based on a principal component, cointegration and Kalman filter analysis of wholesale electricity prices from 2002 to 2006 inclusive, Zachmann's results rejected the assumption of full market integration. De Jonghe et al. (2008) studied the effect of Trilateral Market Coupling (TLC), which took place in November 2006 and coupled the Belgian, French and Dutch electricity markets. Using data from 2002 to 2006 the authors found a sharp decrease in price differences for day-ahead (spot) prices for the two markets they examined – France and The Netherlands. After the coupling, the authors observed more non-simultaneous occurrences of shocks which allowed for smoothing through arbitrage. Furthermore, they found that volatility had only decreased in The Netherlands. In a similar vein, Nitsch et al.'s (2010) analysis led to the conclusion that market integration significantly improved after the TLC, even for markets that were not included in the coupling. The authors used correlation, cointegration and regression analysis for Germany and three neighbouring markets (Austria, France and The Netherlands), for daily electricity spot and futures prices, between 2003 and 2008. They inferred that the three markets are largely competitively interlinked with the German market.

Böckersand Heimeshoff (2012) extended Nitsch et al.'s (2010) investigation of Germany and ten European electricity markets using on and off peak data between 2004 and 2011. Also applying correlation and cointegration analysis, they confirmed that market integration had led to a large increase in price convergence; however only Germany and Austria could be regarded as a joint price area. In summary, they rejected the hypothesis of a fully integrated European market by the end of 2011.

Different from other studies that used wholesale electricity prices, Robinson (2008) employed retail data from 1978 to 2003 for ten European countries (Denmark, Finland, France, Germany, Greece, Ireland, Italy, Portugal, Spain and the UK) and concluded that electricity retail prices had converged. A study by Lundgren et al. (2008) adds to this literature by empirically investigating how price dynamics in the Nordpool changed when the number of integrated markets increased. The authors showed that integrated electricity markets could handle external shocks more efficiently than separate national electricity markets. Examining daily data from January 1996 to February 2006, Lundgren et al. (2008) found that mean electricity prices increased significantly when Finland and Denmark joined the Nordpool exchange, and that price jump intensity decreased. Amundsen and Bergman (2007) also investigated market integration among four Nordic countries (Denmark, Finland, Norway and Sweden) and found that the markets were well integrated, with divergence occurring only during peak periods with low hydro reservoir levels, thus highlighting the relevance of the local electricity mix for price dynamics. Later, Balaguer (2011) assessed market integration for two European countries (Norway and Switzerland) with adjacent markets between 2003 and 2009, and from 2005 to 2009, respectively, using static and dynamic regression analysis. The authors concluded that wholesale electricity market integration in Norway, Denmark and Sweden was robust, thus supporting earlier studies such as Pineau et al.'s (2004) and Amundsen and Bergman's (2007), who also attested to a high degree of market integration in this area. By contrast, in the cases of the electricity markets in Switzerland, France, Germany and Italy, signs of price dispersion as a result of price discrimination of exporters were found. Nonetheless, the dynamic analysis suggested a clear process of convergence over time.

Encompassing previous literature, which had focused mainly on price levels, Bunn and Gianfreda (2010) used causality tests, cointegration and impulse-response techniques on both the price levels and price volatilities of day-ahead, week-ahead, month-ahead and two month-ahead delivery data from July 2001 to July 2005. In general, they found evidence for increasing market integration in Germany, France, Spain, The Netherlands and the UK. The German market was found to be the most integrated market with shock transmission to other markets. The authors attributed this to substantial interconnection capacity, as well as its geographic proximity to many other markets. Interestingly, the UK was also found to be well integrated, despite limited interconnector capacity. In opposition to their original conjecture, the authors did not find integration to be higher in the forward compared to the spot market, which they attributed to market maturity as well as market liquidity.

Bosco et al. (2010) examined weekly spot prices in six European spot markets (Austria, France, Germany, Scandinavia, Spain and The Netherlands) between 1999 and 2007 using cointegration analysis. The authors did not find a common trend for Spain and Scandinavia with any other market, and attributed this finding to peculiarities in the cost/technology characteristics of the electricity generating industries. For the other four markets, however, strong common long-run dynamics could be established.

Nepal and Jamasb (2011) investigated convergence between the Irish electricity market and the Austrian, Belgian, Dutch, German, UK and Nordpool markets between 2008 and 2011 using a time varying Kalman Filter approach. Overall, convergence was found to be either low with Nordpool and the UK or non-existent for associations with the other markets under study. The authors therefore concluded significant opportunities to increase market integration via increased interconnector capacities. Their findings also highlight the relevance of geographical distance to other markets.

Pinho and Madaleno (2011) investigated six European electricity markets (Austria, France Germany, Scandinavia, Spain and The Netherlands) using wavelet analysis (a correlation analysis at different scales) and concluded that between 2000 and 2009, market integration was still in its infancy. In accordance with previous studies (e.g. Bosco et al., 2010; Zachmann, 2008), the assumption of full market integration was rejected. However, there were some regions in Europe where markets appeared highly integrated (e.g. Austria, France, Germany and The Netherlands). Spain and Nordpool on the other hand did not share co-movement with the rest of the European markets. The authors noted the changing behaviour through time and at different frequencies. Pinho and Madaleno (2011) attribute their findings to limited cross-border capacities, different stages in the liberalisation process, and structural differences. A positive change in common price behaviour could be observed from 2003 onwards due to the "Second Directive" (see section 1.2.1) illustrating the usefulness of a common guideline for energy policies. Lindström and Regland (2012) also found market integration to be only partial when considering extreme events in six European electricity spot and forward markets between 2005 and 2010. Based on a pairwise assessment, the authors argued that dependence ranged between almost independent to strongly dependent and that dependence was not always symmetric. In line with Bunn and Gianfreda (2010), the German market especially was found to be co-spiking frequently with all other markets except the Scandinavian market. This underlines the crucial role the German market plays in Europe.

Another recent study (Pellini, 2012) used data up to 2012 and tested for perfect cointegration in 15 European markets using fractional cointegration and a multivariate generalised autoregressive conditional heteroscedasticity (MGARCH) model on spot prices and their volatilities. The author concluded that the integration of European markets still has a "*long way to go*", as less than 40% of the 105 market pairs showed evidence of convergence (Pellini, 2012). Similarly, Autran (2012) contemplated that, despite signs of regional convergence, market integration for the Belgian, Dutch, French and German spot and future markets had not been achieved between 2006 and 2011. Using a Mean Reversion Jump Diffusion Model with time varying estimates, the author found '*stepwise*' convergence. Autran (2012) explained the changes in convergence with peculiar events such as market coupling. Similarly, when employing a regime switching model and assessing patterns in the estimates, Huisman and Kilic (2013) also observed that the impact of price spikes and volatility decreased over time. In addition, they noted that between 2003 and 2010 the parameter estimates converged between the Belgian, Dutch, French, German and Nordic day-ahead prices.

Bollino et al. (2013) assessed the dynamics in four European electricity markets (Austria, Germany, France and Italy) between 2004 and 2010 using cointegration analysis and Granger causality. The authors showed that the German market had a signalling function for neighbouring markets and shared common long-run dynamics with the Austrian, French and Italian electricity markets. Differences observed in price persistence were explained by the respective electricity mixes (highest in France– nuclear dominated – and lowest in Austria– hydro dominated). The Italian market was found to be least affected by price movements in the other markets. This confirms an earlier observation by Creti et al. (2010) who found a modest Italian involvement in the integration process, as Italian decisions on congestion management, traded products and pricing rules are relatively removed from other European countries.

Most recently, Castagneto-Gissey et al. (2014) assessed market integration with dynamic Granger causal networks linking the global connectivity of 13 European electricity markets between 2007 and 2012 to historical events such as market coupling and interconnector commissioning.

All in all, most studies agree that there are some positive developments towards the creation of a common European market for electricity, but that full market integration has not been achieved. Market integration appears to be changing over time and responding, for example, to market coupling and changes in interconnector capacity. A central indicator of an integrated European wholesale market is a single price for electricity, which would demonstrate the ability to manage supply and demand efficiently across national borders. In order to achieve a common price for electricity, a legal framework has been developed that establishes compatible trading arrangements. This framework and other factors that may affect the price formation process (e.g. electricity mix, transmission capacity, and trading arrangements) are therefore outlined in the following section.

## 1.2. Contextual Background

### *1.2.1. Legal Framework of Electricity Market Integration in the EU*

On 25th March 1957, Belgium, France, Italy, Luxembourg, The Netherlands and West Germany signed the European Economic Treaty of Rome, which led to the founding of the European Economic Community in 1958, and aimed:

> "*to promote throughout the community a harmonious development of economic activities, a continuous and balanced expansion, an increase in stability, an accelerated raising of*

*the standard of living and closer relations between the States belonging to it (Treaty of Rome, Article 1)*".

With this treaty the foundations were laid for the creation of an internal market based on the free movement of goods, services, capital and people. On 17th February 1986, the nine Member States (Belgium, The Federal Republic of Germany, France, Ireland, Luxembourg, The Netherlands, Portugal, Spain and the UK) demonstrated support for a common European energy policy by signing the Single European Act, which revised the Treaties of Rome and added new momentum to European market integration. The policy outlined three goals to be achieved by 1993, which were to build a competitive, sustainable and secure European market (Dinan, 2005).

In 1992, the first step towards a new legal framework for an internal electricity market was taken with a proposal for an electricity directive. The policy was adopted four years later as the "First Electricity Directive" (Directive 96/92/EC) and established common rules for the generation, transmission and distribution of electricity. More specifically, it focused on the organisation and functioning of the electricity sector, access to the market, the criteria and procedures applicable to calls for tender, the granting of authorisations and the operation of systems. The First Electricity Directive aimed at:

1. Unbundling, which separates production and supply activities from those of transmission and distribution;
2. Introducing competition in the retail and wholesale markets;
3. Ensuring access which is non-discriminatory to transmission and distribution networks.

However, concrete instructions to reduce the risk of market dominance or to ensure non-discriminatory access to the network were missing. Therefore, in 2003 the European Parliament replaced the First Directive with the "Second Electricity Directive" (Directive 2003/54/EC), which was to be implemented no later than 1$^{st}$ July 2004. It enforces the legal separation of electricity transmission and generation. The Second Directive was accompanied by Regulation (EC) 1228(2003), which introduced some mechanisms for cross-border transit, such as transmission charges and the allocation of available capacities. Despite placing more stringent requirements on the Member States, the Second Directive came short of addressing the issue of separate ownership, or complete unbundling (EWEA, 2012).

In July 2009 the “Third Electricity Directive” (Directive 2009/72/EC) was adopted, and enforced in September 2009, giving its Member States until March 2011 to make it national law. The Third Electricity Directive was motivated by an inquiry conducted by the European Commission, which highlighted excessive horizontal concentration on generation, vertical integration between transmission and generation, and insufficient interconnection. Addressing the shortcomings of the Second Electricity Directive and market asymmetries, the new directive regulated cross-border exchanges of electricity to improve competition, harmonise the electricity markets and legislate full ownership unbundling.

Despite the political ambition to fully complete the integration of EU electricity markets by 2014, and there being a clear timetable for making the directives and regulations national law, Member States are at different stages of implementation as they are allowed some room for manoeuvre.

### *1.2.2. Electricity Trading Arrangements in the EU*

During the initial liberalisation stage of implementing the First Electricity Directive, long-term and short-term electricity contracts were traded bilaterally (OTC: “over-the-counter”). Very soon, however, power exchanges emerged and functioned as central counterparties for its members. Power exchanges in liberalised markets generally consist of: (1) Day-ahead markets, (2) Intraday or balancing markets, and (3) Ancillary services markets. In the day-ahead or spot market, hourly or half-hourly electricity blocks are traded for next day delivery. Participants submit their offers or bids before gate closure, where they specify the quantity and the minimum and maximum price at which they are willing to sell or to purchase. Gate closure is the final call, after which no more offers are accepted. Bids and offers are taken into account and accepted in accordance with transmission capacity limits and the economic merit order criterion. The price is cleared for each trading block. In the intraday or balancing market, the equilibrium between demand and supply as well as adequate reserve margins are managed. The ancillary service market is a venue for trading supply offers and demand bids in respect of ancillary services such as reserves (IPEX, 2014).

The most notable features of the main European electricity exchanges obtained from the 2013 annual reports are summarised in Table 1.1. It is arranged as such: the years the power exchange were founded are listed in the second column, the traded volumes in 2013 are detailed in the third column, column four contains the countries for which electricity is traded on the power exchange, column five lists the number of members in 2013, column six details the gate closures of the different power exchanges for the day-ahead market, and the last column provides information on the price caps (minimum and maximum price) in €/MWh.

Table 1.1: Electricity Exchanges in Europe

| | **Founded** | **Traded volume (spot)** | **Countries** | **Members** | **Gate closure** | **Price caps €/MWh** |
|---|---|---|---|---|---|---|
| **Nordpool (Elspot)** | 1993 | 493TWh | Denmark, Norway, Finland, Sweden, Estonia, Latvia, Lithuania | 361 | 12pm | n.a. |
| **Ipex** | 1999 | 289TWh | Italy | 214 | 9:15am | n.a. |
| **APX-NL** | 2000 | 47.99TWh | The Netherlands | 57 | 12pm | -500 to 3000 |
| **APX-UK** | 2000 | 52.58TWh | GB | 66 | 12pm | n.a. |
| **OMEL** | 2004 | 273TWh | Spain, Portugal | 690 | 10am | 0 to 180 |
| **OTE** | 2001 | 12.99TWh | Czech Republic | n.a. | 12pm | -3000 to 3000 |
| **Belpex** | 2006 | 17.79TWh | Belgium | 42 | 12pm | n.a. |
| **EPEX-FR & EPEX-DE** | 2009 | 346TWh | Germany, Austria, France, Switzerland | 220 | 12pm | -500 to 3000 |

The *Nordic* market for electricity is known as Nordpool Spot and was established in 1993 as a result of the Norwegian Energy Act 1991, as the first multinational electricity exchange. Measured in traded volumes (493TWh in 2013), detailed in column three of Table 1.1, it is the largest spot market under study. In 2013, 361 companies from 20 countries traded on the exchange including generators, suppliers, retailers, traders and large financial institutions. Nordpool was the first international power exchange (then named Statnett Marked AS) and links seven Scandinavian countries: *Norway* (founding country), *Sweden* (from 1996), *Finland* (from 1998), *Denmark* (from 1999), E*stonia* (from 2010), *Lithuania* (from 2012) and *Latvia* (from 2013). EPEX Spot is the second largest electricity exchange in Europe after Nordpool. In 2012, more than 220 companies traded 346TWh of electricity for *Austria*, *France*, *Germany* and *Switzerland*. The French power exchange (Powernext) was launched in November 2001 as an initiative of the European Stock Exchange and Nordpool (Boisselau, 2004). In September 2008 Powernext and EEX merged to form EPEX Spot mutually divided by both companies (EPEX Spot, 2014).

The *Italian* Electricity Exchange (IPEX or Gestore de Mercato Elettrico – GME) was founded as a result of Legislative Decree no. 79 on 16th March 1999 (Legislative Decree 79/99), which made the First Directive national legislation. IPEX is owned by the Ministry of Economy and operates in a monopoly regime, which has been established by law. IPEX is a physical market that acts as a scheduling coordinator and implements market splitting on a national basis, with market rules being connected to the Grid Code (Creti et al., 2010).

The England & Wales Electricity Pool began trading in April 1990 and was at the centre of the liberalisation of the UK's electricity market. APX Power UK (APX-UK, 2013) was established in 2000 as the first independent power exchange in the UK. APX Power NL is the equivalent exchange in The Netherlands, and was also founded in 2000. In October 2010, APX merged with the Belgian Power Exchange (Belpex). APX UK and NL seem less liquid compared to the other markets, as the trade volumes are small and the number of market members is comparably low. Another difference between APX and the other exchanges is that the trade blocks in the day-ahead market are of half-hourly frequency, whereas trade blocks in all other markets are hourly.

*Spain* was the first intercontinental country to launch an organised market for electricity with the Electric Sector Act and royal decree 2019/97, which introduced the market operator Compania Operadora de Mercado Espanol de Electricidad (OMEL). The exchange was established in 1997 and has since been mandatory for all market participants, explaining the large number of market members (690 in 2013) and volumes of electricity traded (e.g. in 2013, 83% of the Spanish electricity consumption was traded on the power exchange). However, with the exception of Portugal, the market is widely isolated from the rest of Europe due to limited transmission capacities which, however, will increase with the commissioning of the Inelfe interconnector to France in 2015. Gate closure is at 10am, two hours before most other European markets. The price caps (0-180€/MWh) in OMEL are much lower when compared to other markets. For example, the Czech electricity operator (OTE) allows prices that have more than 33 times this range (-3000€/MWh to 3000€/MWh).

A level playing field and adequate network capacity are often quoted as necessary conditions for creating an internal European electricity market (Meuus and Belmans, 2008). However, a lack of harmonisation in the market designs of European electricity exchanges can be observed, which may affect the creation of a single European price for electricity. Whereas most exchanges are voluntary, trading on the exchange in Italy and Spain is mandatory, which results in a high number of members and large traded volumes. Gate closures vary across European day-ahead markets, with the earliest in IPEX and OMEL possibly introducing information asymmetries. In the UK and The Netherlands, half-hourly trading blocks are traded. Finally, there are significant differences in price caps, with negative prices allowed in some markets. Nevertheless, some steps towards improving the operational link between power exchanges have been taken, for example via market coupling, which is the use of implicit auctioning involving two or more power exchanges. On 21st November 2006, France, Belgium and The Netherlands coupled their day-ahead markets with the TLC. Four years later (9th November 2010), the TLC was extended with France and Germany to the CWE (Central Western European Market Coupling). On 4th February 2014, price coupling in North Western Europe went live, which covers the CWE region, GB, the Nordics and the Baltics (EPEX Spot, 2014).

### *1.2.3. Electricity Mix and Interconnection in the EU*

Besides market designs and price developments in coupled and interconnected electricity markets, electricity spot price dynamics might also be influenced by technological characteristics or the cost of the marginal fuel. Electricity generation technologies show differences in ramping times, variable and fixed costs, and support schemes. In markets with a high share of hydro-based capacities, such as Scandinavia, fewer abrupt price increases (price spikes) would be expected during periods with sufficient reservoir levels due to the possibility of smoothing demand and supply. Gas-based electricity plants also show short ramping times, implying that supply shocks can be quickly addressed. Nuclear capacities, on the other hand, are difficult to ramp up or down and therefore serve as base load. However, in markets with fossil fuels as a marginal electricity generation technology, fuel price developments and – since 2005 – the price of $CO_2$ might also be reflected in the long-term dynamics of electricity price developments, as they can make up to 70% of the generation cost (Crampes and Fabra, 2005). Therefore, in order to examine electricity price dynamics and electricity market integration, it is important to consider the electricity mix and the interconnection of the markets under study.

The *Belgian* electricity mix is characterised by an increasing share of natural gas, which grew from 8% in 1990 to almost 32% in 2012, and a reduction in coal from 24% to 4% (Eurostat, 2014). Like Germany and Switzerland, Belgium has opted for a law that stipulates the phase-out of its seven nuclear power plants between 2015 and 2025. However, similar to the German nuclear phase-out, the absence of a well-defined capacity replacement plan has led to concerns for the security of the supply (Kunsch and Friesewinkel, 2014).

In the geographical centre of Europe *The Czech Republic* has five cross-border interconnections and a strong internal network making the country a natural electricity transit area. Accordingly, in 2013 it was the third largest exporter of electricity after France and Germany, with exports surpassing imports by 16.9TWh (ENTSO-E, 2014). Electricity is largely generated from domestic coal and nuclear energy, with gas as a complementary fuel in multi-fired units. Despite a decrease from 47TWh of electricity generated by coal in 1990 to 30TWh in 2012, coal is still the largest component in the Czech electricity mix (Eurostat, 2014).

Like Belgium, *France* is characterised by a large share of nuclear-based electricity, however there are no plans for a nuclear phase-out. Because nuclear power stations rely on cooling capacities, precipitation and temperature play an important role in the security of the supply (Böckers et al., 2013). Nuclear generated electricity increased from 314TWh in 1990 to 425TWh in 2012, which is equal to a 76% share in the French electricity mix. Due to this high value, France is one of the least $CO_2$ intensive industrialised economies (IEA, 2009). In 2013, France was a net exporter of its electricity. Gaining from price differentials, it exported 58.2TWh of electricity to its interconnected market. Most exports went to Italy (12.7TWh) and GB (10.9TWh), but also to Germany, which decided against nuclear energy in its domestic electricity mix (ENTSO-E, 2014).

The electricity mix in *GB* has undergone major shifts. Between 1990 and 2012 electricity from coal-fired plants decreased from 64% to 40%, and has been replaced with electricity from gas-fired plants which increased from 2% to 38% (Eurostat, 2014). EU targets require that by 2020, 15% of all of GB's energy should be generated from renewable sources. The scenario from the British renewable energy strategy suggests that this target could be met by a 30% renewable contribution in electricity generation. At the same time, 20% of GB's electricity generating capacities (93.4GW in 2010) are expected to be closed by 2020. The Large Combustion Plant Directive will lead to a closure of 12GW by 2016, with further closures being expected before 2016 enforced by the EU Industrial Emissions Directive. This decrease in capacity means that reserve margins could fall below 5% in the next decade, increasing the likelihood of blackouts, thus increasing dependency on foreign electricity imports (IEA, 2012). In fact, limited reserve margins may already be reflected in the country's import–export statistics: in 2013 only 4.4TWh of electricity was exported (mainly to Ireland) but almost four times as much (17.5TWh) was imported (from France and The Netherlands).

In contrast to GB, *Germany* is a net exporter of electricity. Since 1990 the country is the largest electricity producer in Europe with a diversified electricity system that benefits from strong cross-border interconnections. Thus, 44% of the electricity generated in 2012 was produced using coal, making Germany a large CO2 emitter. However, a decision has been made to phase-out domestic coal mines by 2018. Furthermore, substantial coal-fired plants are likely to be decommissioned with the enforcement of the Large Combustion Plant Directive in 2016. Nevertheless, several new coal-fired plants are under construction with a technical lifetime lasting until at least 2050. This development appears to conflict with targets aiming to reduce greenhouse gas emissions by 80-95% by 2050 compared to the level in 1990, with interim steps of 35%, 50% and 75% by 2020, 2030 and 2040 respectively. Moreover, the *Atomgesetz* (Nuclear Act) was legislated to successively close all nuclear power stations, which are low in CO2 emissions, until 2020. In 2012, more than 16% of the local electricity mix consisted of nuclear generated electricity, whose annual output increased from 153TWh in 1990 to 167TWh in 2006. Since then, a decline in nuclear power output can be observed to a value of 100TWh in 2012 (Eurostat, 2014).

Despite the changes in Germany´s electricity mix, in 2013 the country maintained its position as Europe's largest electricity exporter.

Due to significant price premiums in the *Italian* electricity wholesale market, Italy is a net importer, and in 2013 exported only 5% (2.2TWh) of the amount it imported (44.5TWh). The Italian electricity mix stands out from the other markets under study due to a previously high share of oil. In 1990, 56% (103TWh) of Italy´s electricity was produced by oil generated plants (23% by gas and 17% by coal). In 2012, the share of oil in the Italian electricity mix was reduced to only 6%, which is similar to the value for wind generated electricity. The share of gas increased to 45%, which equals 136TWh. Electricity generated by coal remained almost constant between 1990 and 2012 at 16% (Eurostat, 2014).

When considering gross electricity generation in *Scandinavia* (Finland, Norway and Sweden), hydrogenerated electricity is dominant. In 2012, 62% or 238TWh was produced by hydro, which is an increase of 10% compared to the value in 1990. Besides being low in emissions, the main advantage of hydrogenerated electricity is its storability: hydro capacities can be used to smooth the supply fluctuations of other generation technologies. However, similar to nuclear generated electricity, which contributed around 22% to the electricity mix in Scandinavia, the output is dependent on precipitation (Eurostat, 2014).

The rapid development of Combined Cycle Gas Turbines (CCGTs), as well as wind power, has diversified *Spain´s* generation mix between 1990 and 2012. In the 1990s, most of the electricity was generated by coal, oil, nuclear and hydro. From 1990 to 2010, gas-fired electricity output grew by 72TWh, driven first by the need for fast capacity increases and later by the EU-ETS carbon prices. Similarly, there was strong growth between 1990 and 2012 for wind power generated electricity, growing from 14GWh to 49500GWh. In the first half of 2013, around 48% of electricity was supplied by renewable energies, much of which had variable output. With regard to Spain's weak interconnection, the integration of large-scale renewable energies to the system whilst securing electricity supply has been one of the main challenges. In 2013, Spain was a net exporter of electricity with 10.3TWh of imported electricity and 16.7TWh of exports.

Total gross electricity generation in *The Netherlands* was 102.5TWh in 2012. Compared to 2011, this is a decline of 9.3%, the largest annual contraction over the past three decades (since mid-1980s) (IEA, 2014). The electricity mix in The Netherlands is dominated by fossil fuels, with gas contributing 58% and coal contributing 26% to the mix. However, since 2010 the share of gas is declining and government projections indicate that the share of all fossil fuels in the electricity mix will further decrease to 71.5% by 2030. Within 10 years renewable generated electricity has increased from 5.7% to 14% (2002-2012), consisting mainly of biofuels, waste and wind. Solar and hydro also play a role, contributing 0.3% and 0.1% of the total gross electricity generation in 2012, respectively. Also in 2012, the total installed generating capacity in The Netherlands was around 29GW after a strong growth, which has led to a significant capacity surplus (IEA, 2014). Similar to the Czech Republic, The Netherlands is a transit country, and in 2012 about 15% (14.8TWh) of gross domestic electricity generation was exported and 33% (33.3TWh) imported.

The outlined developments of the electricity generation mix of the markets under study show large differences and significant changes over time. Decisions to phase out nuclear capacities in Belgium, Germany and Switzerland, or to increase the share of RES-E, indicate that the electricity mix will continue to change. In principle, national authority makes decisions on the local electricity mix, and European energy laws only frame this independence. The Large Combustion Plant Directive, for example, will enforce strict environmental compliance, setting the limits of pollutants that apply to each coal- or gas-fired station of size 50MW or more. Coming into force by 2016, the directive will lead to reduced capacity, especially in markets with a high share of coal and gas in its electricity mix. In interconnected systems these changes should be considered in the assessment of electricity market integration.

### *1.2.4. Research Question*

The outlined literature on electricity market integration suggested that factors and special events such as market coupling, changes in interconnector capacities, time of day and geographical extension might influence electricity price convergence. The contextual background highlighted that the local electricity mixes and capacity levels changed over time, cross-border interconnections varied, and trading arrangements were not harmonised across European markets.

Nonetheless most empirical analyses were based on models with fixed parameters and did not consider special events that might have affected market integration. The central purpose of this doctoral thesis is to address the following research question:

> *Are liberalised European electricity markets converging to a single internal market for electricity?*

In contrast to most of the previous literature, a time-variant approach to the investigation is proposed, and therefore the following three questions are examined:

1. *How has electricity market integration evolved over time and what factors drive convergence and divergence of electricity prices in the EU?*

The first study, detailed in chapter two, is titled "*Reassessing the Integration of European Electricity Markets: A Fractional Cointegration Analysis*" and investigates electricity price convergence in liberalised European electricity markets, using data from nine spot and four one-month ahead markets. First, changes in long-run electricity price behaviour will be examined. Thereafter, price convergence in spot and forward markets will be assessed and compared, while allowing for changes over time that could be linked to special events, such as fuel price increases or extreme weather conditions. In the third part of the study, special events such as additional interconnector capacity, market coupling and Germany´s closure of eight nuclear power stations will be assessed with regard to possible implications for electricity market resilience.

Given the relevance of the local electricity mix and its potential effect on market integration, the second research question is:

2. *How do fuel and carbon prices associate with electricity prices and do they impact on electricity market integration?*

Three case studies are conducted assessing time-varying convergence between electricity spot prices, fuel and carbon prices, as well as in each case two adjacent electricity markets. The investigation is presented in chapter three. The three cases that will be investigated are the British, the Nordpool and the French electricity spot (day-ahead) markets, which have different electricity mixes and varying degrees of physical interconnection with other markets.

In “*Germany’s Nuclear Power Plant Closure and the Integration of Electricity Markets in Europe*”, the fourth chapter of the thesis, the underlying research question is:

3. *How does an increased level of renewable electricity impact on electricity price dynamics and on market integration?*

Following Germany´s nuclear power plant closures, the share of wind power in the German electrical system increased significantly. The implications from the changes in the electricity mix of the largest European market for electricity market integration will be assessed. Changes in the short- and long-run dynamics of electricity spot prices in Germany and interconnected markets are investigated as well as any changes in convergence to a common internal market for electricity. Repercussions for other electricity markets will be discussed and policy implications outlined.

# 2. Reassessing the Integration of European Electricity Markets: A Fractional Cointegration Analysis

This chapter extends existing literature on electricity market integration, by adopting a time-varying fractional cointegration analysis of daily electricity prices (spot and one-month ahead) to model electricity prices. The potential impacts of special events that may affect system capacity, such as market coupling, new interconnectors and Germany's closures of eight nuclear plants on the convergence of European spot markets (APX-UK, APX-NL, Belpex, EPEX-FR, EPEX-DE, IPEX, Nordpool, Omel and OTE) and month-ahead markets (French, British, German and Dutch) are also evaluated. Daily spot prices from February 2000 to March 2013 and month-ahead prices from November 2007 to December 2012 are analysed. Results show that unit root tests, which have been generally used in the previous literature that tested market integration, are inadequate for assessing electricity spot market convergence because spot prices are found to be fractionally integrated and mean-reverting time series. Furthermore, spot price behaviour and their association with different markets change over time, possibly reflecting changes in the EU electrical system. One-month-ahead prices, by contrast, are observed to be more stable over time, but do not revert to a mean.

## *2.1. Introduction*

The present study aims to assess whether liberalised European electricity wholesale markets are increasingly associated and converging to a single price. Empirical evidence is important since the integration of European electricity markets has been in process for many years and was planned to be completed by 2014 (European Commission, 2012b). The first step towards a pan-European liberalised wholesale market was taken in 1996 with EU Directive 96/92/EC, which defined common rules for the generation, transmission and distribution of electricity and aimed at creating an efficient supranational European market (Gebhartd and Höffler, 2007). Subsequent electricity market directives (e.g. 2003/54/EC and 2009/72/EC) have also addressed emission targets for the electricity sector and specified paths to integrate renewable energy. In the last decade, cross-border transmission has been fostered through energy transactions at power exchanges and electricity markets have been joined via interconnectors, such as the NorNed linking Norway and The Netherlands. Market coupling initiatives attempt to optimise the usage of interconnector capacity and to ensure that electricity flows from low to high price areas. Yet, in the last quarter of 2012, the European Commission claimed that a pan-European market for electricity was delayed, because member states were slow in adjusting their legislation and most energy policies remained centred on national interests (European Commission, 2012b). Since decisions on electricity mixes and system capacity are made by individual states, they may conflict with the aims of competitive prices and security of supply in connected markets. In this context, an assessment of the speed of mean reversion of wholesale prices to a common price is informative for regulators and policy-makers, both locally and regionally, because it indicates how quickly and flexibly the supply side reacts to unexpected events (Bosco et al., 2006). This study investigates the speed of mean reversion and convergence of electricity prices in nine European spot markets and four one-month-ahead markets. In contrast to previous literature, it allows for associations between markets to be time-varying, in the sense that the model specification can vary over time. It also analyses how specific events that may have an impact on electricity generation and cross-border transmission capacity in one market may intervene in the process of electricity market integration.

The chapter is divided into six parts. In the next section, the literature on electricity market integration is reviewed. Section three sets the hypotheses to be tested and identifies special events that are likely to affect European electricity wholesale prices and, consequently, have an impact on their co-movement. The fourth section describes the method that is adopted to model the long run dynamics of electricity prices in the study, which are reported in section five. Finally, section six summarises the findings and concludes the chapter.

## *2.2. Previous Assessments of Market Integration*

Most literature on electricity market integration used the Law of One Price (Fetter, 1924) as the theoretical foundation for determining whether two geographic regions, in which a well-defined product is traded, comprise a single market. Accordingly, cointegration analysis (Johansen, 1988, 1991) became the most used econometric method for assessing market integration (used for example by: Böckers and Heimeshoff, 2012; Bosco et al. 2010; Bunn and Gianfreda, 2010; Balaguer, 2011; Kalantzis and Milonas, 2010; Nitsch et al, 2010). Among cointegration studies of electricity prices, Robinson (2007, 2008) focused on retail data from 1978 to 2003 for ten European countries (Denmark, Finland, France, Germany, Greece, Ireland, Italy, Portugal, Spain and the UK), and concluded that electricity prices in these countries had converged. However, this method requires the time series to follow a trend, and as such, may be too restrictive when investigating the time series behaviour of electricity spot prices which have often been described as stationary or mean-reverting processes (Karakatsani and Bunn, 2008). In fact, the suitability of this method for the analysis of electricity prices was already questioned in one of the early studies of market integration, when Boisselau (2004) analysed six European spot electricity markets in 2002, and observed that most price series were stationary, thus concluding that the nature of the data did not allow for testing long run integration. Subsequently, Armstrong and Galli (2005) examined the four main electricity day-ahead wholesale markets in the Eurozone with common borders and similar price-setting processes (France, Germany, The Netherlands and Spain), and found that the average price difference decreased between January 2002 and December 2004 in almost all pairs of markets, but more so during peak periods of demand. Consequently, they inferred that prices in the main continental European markets were converging. Nevertheless, Zachmann (2008) showed that by mid-2006, market integration of eleven European markets (Austria, the Czech Republic, East Denmark West Denmark, France, Germany, Netherlands, Poland, Spain, Sweden and the UK) had not been attained.

Overall, there are some indications of price convergence in subsets of markets. For example, the studies of De Jonghe et al. (2008) and Nitsch et al. (2010) concerning the effect of market coupling on day-ahead prices in Belgium, France and The Netherlands, found a sharp decrease in price differences after the market coupling event, which took place in November 2006. Bosco et al. (2010) also concluded that weekday daily average prices in the German and French markets were integrated. Moreover, Bunn and Gianfreda (2010), who analysed price levels and volatilities via cointegration analysis, causality tests and impulse-response models, found evidence of increasing market integration between Germany, France, Spain, The Netherlands and the UK. Yet, they rejected their hypothesis of higher integration in the forward market than in the spot market. In addition, Huisman and Kilic (2013), when using regime switching models to capture changes between 2003 and 2010, observed a decrease in the impact of price spikes and volatility, and also noted the similarity in the parameter estimates of the Belgian, Dutch, French, German and Nordic models of day-ahead prices. Yet, a study of six European spot and forward markets in the period between 2005 and 2010 (Lindström and Regland, 2012) concluded that integration was only partial, therefore supporting the findings of Balaguer (2011), who examined the period between 2003 and 2009, and showed that, while wholesale electricity markets in Denmark and Sweden were highly integrated, prices in France, Germany and Italy diverged.

In this context, three recent studies explicitly question integration in Europe. Pellini (2012) used fractional cointegration to assess the convergence of 15 European spot markets, and determined that the integration of European markets still has a long way to go. In a similar vein, Autran (2012) concluded that, despite signs of regional convergence, market integration of the Belgian, Dutch, French and German spot and future markets had not been achieved in the period between 2006 and 2011. In contrast to previous studies, the latter conclusion is based on a jump diffusion model with time varying estimates, and the author observed a *“stepwise”* convergence, which might be explained by market coupling. More recently, Castagneto-Gissey et al. (2014)

explored time-varying interactions among 13 European electricity markets between 2007 and 2012 using Granger-causal networks, and found that a peak in connectivity concurred with the implementation of the Third Energy Package. Furthermore, they observed that market coupling and interconnector commissioning increased the association between markets, however they agreed with Pellini's conclusion (2012) that market integration remains to be achieved.

All in all, the literature suggests that there are variations in how electricity markets might be associated within the EU, and reinforces the need for further examining integration within a time-varying framework that explores the potential impact of special events. Most studies have used models with fixed parameters, which cannot capture contextual changes. Some authors (Huisman and Kilic, 2013; Bunn and Gianfreda, 2010) allowed for changes in a yearly basis, but may have been unable to identify special events within the whole period studied since they assessed convergence for each year in their study.The present study attempts to overcome some of the limitations in the literature by allowing the time series to vary between mean reversion and non-stationarity. Furthermore, the time-varying framework, which is adopted, enables the assessment of the possible effects of special events on electricity price convergence.

### *2.3. Hypotheses*

Central to this study are the long run price dynamics of evolving EU electricity markets, which can be screened for changes. Given the objectives of the directives on liberalisation and integration, resilience and flexibility should have increased, therefore:

H1: *As liberalisation evolves, the ability of EU electricity markets to overcome supply and demand shocks more quickly increases.*

Whenever demand surpasses the available transmission capacity, price convergence is inhibited, and two separate pricing areas are likely to prevail (Belpex, 2013). Given the increasing interconnectivity and the gradual implementation of EU directives, which ultimately prescribe a pan-European market, electricity prices in markets subject to these policies should converge:

H2a: *EU electricity markets are increasingly integrated.*

Since forward and future contracts are subject to less uncertainty (they are less exposed to the impact of extreme weather conditions or unplanned power plant failures; base-load capacity, which is traded in forward contracts, is more stable and therefore predictable), European electricity forward markets are likely to display stronger (more persistent) cointegrating relationships compared to spot markets. Hence, following Bunn and Gianfreda (2010), we test:

H2b: *Greater cointegration is observed in electricity forward prices when compared to prices in the respective spot markets.*

Recent market coupling initiatives aim to maximise the total economic surplus of all participants: cheaper electricity generation in one electricity market can meet demand and reduce prices in a connected market, therefore supply fluctuations can be balanced (Belpex, 2012). Increased price resilience is expected after market coupling and greater interconnector capacity, at least in those markets which are directly coupled or interconnected. Consequently:

H3a: *The speed of mean reversion after a market connecting event is faster than the mean reverting speed of the price series before the event.*

In contrast, when neighbouring markets are not directly joined, i.e. when they are neither a part of a market coupling initiative nor linked by an interconnector:

H3b: *There is no change in the speed of mean reversion of spot prices in markets which are not directly affected by the new interconnection.*

National policies that have an impact on a market's generation capacity may also affect electricity price dynamics in neighbouring markets. In the particular case of Germany's nuclear phase-out act of 2011, base load capacity was reduced after the closure of eight plants between March and August 2011, thus changing the German market's supply stack (increase in the share of intermittent renewables in the electricity mix). Given Germany's geographically central position as well as the size of its market, we hypothesise:

H3c: *Germany´s decrease in secure capacity has lowered the ability of electricity spot prices to revert to the mean in the German and neighbouring markets.*

### *2.4. Methods*

#### *2.4.1. Assessing Mean Reversion: Integration and Fractional Integration*

The Phillips and Perron test (PP) and KPSS test (KPSS), which have been proposed by Phillips and Perron (1988) and Kwiatkowski et al. (1992) respectively, can be used to test for a trend or unit root in a time series. While in the former test, the alternative hypothesis of a mean reverting stationary series is tested against the null hypothesis of a trended time series, in the KPSS test the opposite is assessed. Since electricity spot prices are commonly found to be mean reverting (e.g., Escribano et al., 2002; Lucia and Schwartz, 2002; Knittel and Roberts, 2005; Worthington et al., 2005) and their time series show periods of high and low volatility with spikes that take some time to dilute (Bunn and Gianfreda, 2010), they are unlikely to have a unit root (be an integrated process of order 1, *I(1)*). Consequently, a less restrictive framework is needed when modelling electricity spot prices.

In this context, fractionally integrated processes are more suitable to describe electricity spot prices, because they exhibit a temporal dependence that is intermediate between an *I(1)* (unit root or non-stationary) and an *I(0)* (stationary) process. 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:

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

where *d,* which is the parameter describing the speed of mean reversion, 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, 1994b).

In testing hypothesis 1 and assessing the speed of mean reversion, we use the Exact Local Whittle (ELW) estimator by Shimotsu and Phillips (2005) and the semi-parametric two-step Feasible Exact Local Whittle (FELW) estimator by Shimotsu (2006) to estimate the order of integration *d* of electricity price time series. The semi-parametric ELW and FELW estimators have been described as robust against misspecification of the short run dynamics of a process (Okimoto and Shimotsu, 2010) and are therefore attractive when assessing whether a time series is fractionally integrated. The FELW is applicable to 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.

### 2.4.2. Assessing Price Convergence: Fractional cointegration

Fractional cointegration (Granger, 1986; Engle and Granger, 1986; Johansen, 1988) is the co-movement of fractionally integrated time series, i.e.: *Two time series $x_t$ and $y_t$, integrated of order d, are said to be fractionally cointegrated of order (d, b) if the error correction term given by*

$$z_t = y_t - \beta * x_t \quad (2)$$

*is fractionally integrated of order b, where $0 < b \leq d$* (Banerjee and Urga, 2005).

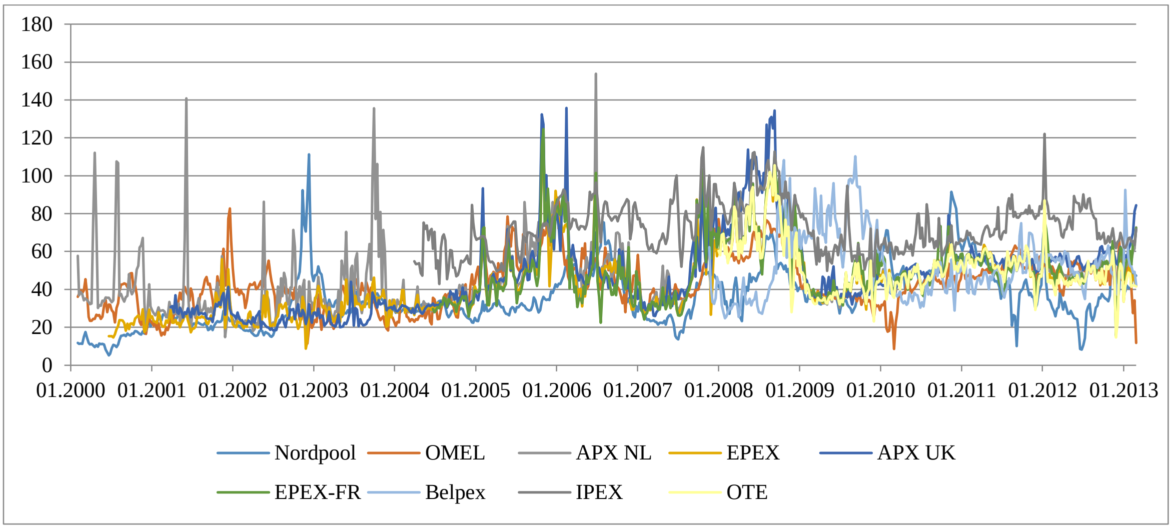
Rolling cointegration procedures following Hansen and Johansen's (1999) or Rangvid and Sørensen's (2002) proposals for unit root time series have been generalised to test fractionally integrated time series. In rolling tests for cointegration, the sample size is kept the same, but the sample period (window) is allowed to vary (Rangvid and Sørensen, 2002). These tests have been previously employed in different contexts and data, e.g. international inflation rates (Kumar and Okimoto, 2007), spot and forward exchange rates (McMillian, 2005) and commodity futures prices (Fernandez, 2010). In this context, it is noteworthy that Pellini (2012) also used fractional cointegration to assess price convergence in EU electricity markets, but has relied on a less robust estimator (Geweke and Porter- Hudak, 1983; Robinson and Henry, 1999) rather than the FEWL estimator. Furthermore, her analysis did not adopt a rolling window and focused on the whole time series, thus she did not assess the potential changes over time, which might be expected due to special events that might have affected the electricity markets during the period examined.

## 2.5. The Empirical Study

### 2.5.1. Data

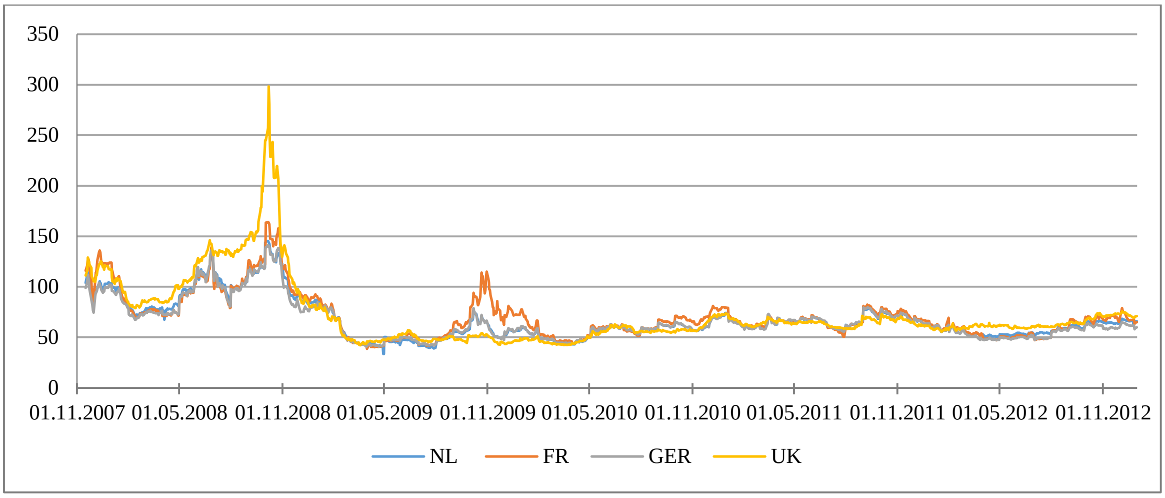
We analyse weekday daily electricity spot and month-ahead price series. Hourly or half-hourly electricity spot prices from APX-NL (The Netherlands), APX-UK (GB), EPEX-DE (Germany), EPEX-FR (France), IPEX (Italy), Nordpool (Denmark, Finland and Sweden; plus Estonia (from 2010), Lithuania (from 2012) and Latvia (from 2013)) OMEL (Spain and Portugal) and OTE (Czech Republic) power exchanges in €/MWh, £/MWh or NOK/MWh have been transformed to mean-average weekday daily prices and converted to €/MWh using the daily exchange rate from Datastream (Reuters, 2013). The data sources are either the respective spot markets (the Amsterdam Power Exchange, the European Energy Exchange, Gestore Mercati Energetici, Nordpool, Operador del Mercado Ibérico de Energía or Operator trhu s elektrinou) or Datastream (Reuters, 2013). Different starting dates are considered in order to allow for an investigation of the longest publicly available samples at the time of the data collection. As illustrated Figure 2.1, the spot series for APX-NL, Nordpool and OMEL began on 28 February 2000; EEX-DE on 17 July 2000; APX-UK on 25 April 2001; IPEX on 30 April 2004; EPEX-FR on 23 July 2004; and Belpex on 21 December 2006. OTE is the shortest sample, beginning on 29 January 2008. All electricity spot price series ended on 29 March 2013. It is noticeable that all time series are volatile with upwards and downwards spikes that often take some time to revert to their previous level. IPEX tends to show higher prices and a larger frequency of periods with similar behaviour. Generally Figure 2.1 suggests some co-movement, but there are also large spikes or outliers that appear to be unique to a particular market and may affect the assessment of correlation.

Figure 2.1: Weekly electricity spot price series in €/MWh from February 2000 to March 2013.




The month-ahead price data, which was obtained from Platts, covers a subset of four interconnected markets in the following countries: France, GB, Germany and The Netherlands. The time series observations are of weekdays (Mondays to Fridays) in the period between November 2007 and December 2012, thus comprising 1,337 observations per forward market. The time series are plotted in Figure 2.2, which show that month-ahead prices are less volatile and move more closely than observed in Figure 2.1. The strong bull run of electricity prices in the second quarter of 2008 might be traced back to a price hike of Brent crude oil (European Commission, 2008a). In the third quarter of 2008 electricity forward prices started to deflate as the economic crisis became more concrete (European Commission, 2008b).

Figure 2.2: Weekday daily electricity forward prices in €/MWh from November 2007 to December 2012




### *2.5.2. Analysis Procedure*

Prior to the analysis of the spot price data, an outlier treatment inspired by Trück et al. (2007) was conducted. Accordingly, outliers were defined as observations which exceeded the rolling window mean average by three standard deviations over a one-month period and were replaced by the mean average. After five iterations, convergence was achieved. Neither bootstrapping nor other data treatment, were required. The forward price time series were well-behaved and therefore the raw data were considered.

An assessment of the order of integration $d$ is carried out by comparing unit root tests with estimates of the order of fractional integration over the entire sample period. To test hypothesis 1 and assess mean reversion, we examine the summary statistics and plots of estimated values for $d$ and 95% confidence intervals over the sample period by means of a rolling window estimation using FELW and a window size of 200. We set the bandwidth $m$ for estimating the FELW to 54, as proposed by Lopes and Mendes (2006). As a faster speed of mean reversion would imply having a downward trend in estimates of the order of integration $d$. Ordinary least square regressions (OLS) are estimated for each time series:

$$\hat{d}_t = c + \alpha \hat{d}_{t-1} + \varepsilon_t \tag{3}$$

where: $\hat{d}_t$ is the estimated order of integration, $c$ is the constant or average $d$, $\varepsilon_t$ is the error term and $\alpha$ the slope coefficient. The slope coefficient $\alpha$ should be negative (5% significance level) for hypothesis 1 to be supported by the data.

A fractional cointegration analysis is conducted to test hypotheses 2a, whether markets are becoming more integrated, and 2b that integration is greater in the forward markets than in spot markets. The necessary conditions for a time series to be fractionally cointegrated are: (1) having a common order of integration ($0<d<1$); (2) an error correction term, which is obtained by rolling window ordinary least square regressions (OLS), of lower order of integration. In case of hypothesis 2a, the percentage of days on which the time series was fractionally cointegrated before 21 November 2006, which is when the TLC and the Belgian power exchange (Belpex) were launched, are compared with the percentage of days on which they were fractionally cointegrated after the date. The forward price data are divided into two series of equal length, the split date is 09.06.2010. One-tailed tests for differences in proportion are used to assess whether there was support for increasing integration (i.e. the proportion after the split date was greater than before). Thereafter, another one sided t-test assesses changes in price dispersion. Price dispersion should decrease as convergence increases, i.e. less price dispersion is expected after the event. Convergence for of all markets that are directly interconnected is then graphically analysed. The order of integration *d*, which is estimated using a rolling window of 200 observations, is plotted for each pair of price series as well as the error correction term for the longest possible common period determined by the shorter series. The plots are smoothed using a HP filter (Hodrick and Prescott, 1980) and a smoothing parameter $\lambda = 250$. When testing hypothesis 2b, we compare four pairs of spot and forward markets to assess significant differences regarding the degree of convergence over a common time span. We test if convergence in forward markets is larger than convergence in spot markets.

Variants of hypothesis 3 are tested via the Chow (1960) breakpoint test, which is the most commonly used test to assess the presence of a structural break with a known date. One hundred perturbed series, in which a *N(0,1)* distributed noise is added to the original price series, are generated and their order of integration is estimated by using FEWL for 260 observations, corresponding to a period of one year, both before and after the special events. For hypothesis 3a, a one-tailed *t*-test of means before and after the event is conducted when the markets were to have been affected by the special event:

$$H_0: d_{after} = d_{before},$$

$$H_1: d_{after} < d_{before}$$

A two tailed *t*-test is then used for markets that could have been indirectly affected by the special events. For hypothesis 3b, we test:

$$H_0: d_{after} = d_{before},$$

$$H_1: d_{after} \neq d_{before}$$

In order to test hypothesis 3c, whether or not Germany´s energy transition has lowered the ability of electricity prices to revert to the mean in Germany and in neighbouring markets, we test:

$$H_0: d_{after} = d_{before},$$

$$H_1: d_{after} > d_{before}$$

### *2.5.3. Empirical Results*

#### *2.5.3.1. Electricity Spot Prices*

Table 2.1 summarises the data distribution and electricity price behaviour after the outlier treatment. The first column shows that mean prices range between 35.44€/MWh (Nordpool) and 72.62€/MWh (IPEX); the minimum daily mean average is observed in OTE (-13.39€/MWh) and the highest daily mean average in APX-NL (191.81€/MWh). Standard deviations, as shown in column five of Table 2.1, vary between 13.88€/MWh and 20.02€/MWh with IPEX having the least and APX-NL the most amount of variation. Positive skewed distributions and excess kurtosis are observed in all markets.

##### *2.5.3.1.1. Integration and Fractional Integration of Electricity Spot Prices*

The Phillips and Perron (1988) unit root test (PP) and the KPSS test of Kwiatkowski et al. (1992) are reported in column nine and ten respectively. According to the PP test, a unit root is rejected for all price series, thus implying that factional cointegration suits the data and standard cointegration analysis (Johansen, 1988, 1991) is not reliable. KPSS rejects the hypothesis of stationarity for almost all electricity spot markets with the exception of Belpex, IPEX and EPEX-FR. The rejections of the opposite null hypotheses by the tests suggest that APX-NL, APX-UK, Nordpool, OMEL and OTE electricity spot prices are neither mean-reverting nor trended. In fact, similar conflicting evidence has been documented in the literature: Escribano et al. (2002), Lucia and Schwartz (2002), Knittel and Roberts (2005), Worthington et al. (2005) and Bunn and Gianfreda (2010) found electricity prices to be *I(0)*; by contrast, De Vany and Walls (1999) and Bosco et al. (2010) concluded that electricity prices were *I(1).* A possible explanation for this contradiction has been offered by Diebold and Rudebusch (1991) and Sowell (1990), who have shown that the power of standard unit root tests is low, when the true time series process is fractionally integrated. Indeed, this explanation is consistent with the estimates of the order of integration that are shown in Table 2.1, where we observe that both the ELW and FELW estimators, (columns 10 and 11) are in the interval (.5; 1], thus supporting the adoption of the fractional cointegration framework in this study.

*2.5.3.2. Month-ahead Electricity Prices*

The month-ahead prices are summarised in Table 2.2, and are reasonably well-behaved. Their mean average are found to be higher than average spot prices, as shown in the first column; they range from 66.15€/MWh in Germany to 72.22€/MWh in GB, and reflect the added risk premium and expectations of generation costs.

*2.5.3.2.1. Integration and Fractional Integration of Electricity Forward Prices*

Estimates of the order of integration range from 0.886 (France) and 1.085 (GB), in the case of the ELW, and between 0.922 (Germany) and 1.152 (GB) when based on the FELW, thus suggesting that month-ahead prices are non-stationary. Columns eight and nine of Table 2.2 report the statistics of the KPSS and PP unit root tests. They confirm a trend in all electricity forward price series, apart from France, for which there is an apparent contradiction: according to the KPSS tests statistics the series is stationary (*I(0)*), while according to the PP test the series has a unit root (*I(1)*). Furthermore, the order of integration $d$ for all price series, based on the ELW and FELW estimators, have overlapping 95% confidence intervals, as shown in columns 10 and 11.

Table 2.1: Summary statistics for electricity spot prices from February 2006 to December 2012

| | **Mean** | **Median** | **Max** | **Min.** | **Std. Dev.** | **Skew.** | **Kurt.** | **PP** | **KPSS** | **ELW** | **FELW** | **Obs.** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| APX_NL | 48.16 | 45.56 | 191.81 | 2.05 | 20.027 | 1.593 | 7.886 | -21.099** | 1.515** | .547 [.546; .549] | .550 [.548; .551] | 3415 |
| APX_UK | 47.28 | 44.27 | 184.74 | 16.27 | 21.633 | 1.573 | 6.881 | -9.822** | 2.458** | .639 [.637; .640] | .627 [.625; .629] | 3113 |
| BELPEX | 52.92 | 49.81 | 128.68 | 15. 11 | 18.419 | 1.009 | 3.996 | -6.521** | 0.324 | .662 [.659; .665] | .650 [.647; .653] | 1376 |
| EPEX-DE | 42.91 | 40.95 | 145.97 | 3.47 | 17.606 | 1.094 | 5.256 | -11.060** | 3.295** | .600 [.598; .602] | .586 [.585; .588] | 3315 |
| EPEX-FR | 51.57 | 48.69 | 154.76 | 7.11 | 18.025 | 1.258 | 5.410 | -11.144** | 0.246 | .659 [.657; .661] | .672 [.670; .674] | 2267 |
| IPEX | 72.62 | 71.06 | 136.67 | 27.51 | 13.879 | 0.480 | 3.605 | -12.795** | 0.456 | .648 [.646; .650] | .663 [ .661; .665] | 2326 |
| Nordpool | 35.44 | 32.82 | 114.81 | 4.76 | 15.140 | 0.964 | 4.772 | -4.658** | 2.360** | .857 [.855; .858] | .853 [.851; .854] | 3415 |
| OMEL | 42.95 | 41.58 | 103.76 | 0.79 | 14.315 | 0.435 | 3.218 | -8.016** | 1.507** | .717 [.715; .719] | .726 [.724; .728] | 3415 |
| OTE | 51.33 | 49.12 | 120.07 | -13.39 | 14.906 | 1.098 | 5.547 | -8.581** | 0.877** | .705 [.702; .708] | .656 [.653; .660] | 1349 |

*, ** denote a 5% and 1% level of significance, respectively. For the PP test, the null hypothesis is $\boldsymbol{H_0}$: $\boldsymbol{y_t}$ has a trend. Critical values are -3.43 for a 1% significance level and -2.86 for a 5% significance level. For KPSS, the null hypothesis is $\boldsymbol{H_0}$: $\boldsymbol{y_t}$ is stationary. Critical values are 0.739 for a 1% significance level and 0.463 for a 5% significance level.

Table 3.2: Summary statistics for one-month forward electricity prices from November 2007 to December 2012

| | **Mean** | **Median** | **Max.** | **Min.** | **Std. Dev.** | **Skew.** | **Kurt.** | **PP** | **KPSS** | **ELW** | **FELW** | **Obs.** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FR | 70.54 | 66.25 | 164.25 | 38.50 | 22.16 | 1.43 | 5.21 | -3.093* | 1.3024** | 0.886 [.792;.970] | 0.925 [.831;1.019] | 1337 |
| GB | 72.22 | 61.92 | 298.20 | 42.07 | 32.73 | 2.69 | 12.45 | -2.528 | 1.248** | 1.085 [.991;1.179] | 1.152 [1.058;1.246] | 1337 |
| GER | 66.15 | 60.95 | 141.50 | 40.90 | 19.34 | 1.50 | 5.20 | -2.661 | 1.333** | 0.888 [.794;.972] | 0.922 [.828; 1.016] | 1337 |
| NL | 67.24 | 61.80 | 145.60 | 33.60 | 19.95 | 1.36 | 4.66 | -2.492 | 1.332** | 0.932 [.838;1.026] | 0.986 [.892;1.080] | 1337 |

*, ** denote a 5% and 1% level of significance, respectively. For the PP test, the null hypothesis is $\boldsymbol{H_0}$: $\boldsymbol{y_t}$ has a trend. Critical values are -3.43 for a 1% significance level and -2.86 for a 5% significance level. For KPSS, the null hypothesis is $\boldsymbol{H_0}$: $\boldsymbol{y_t}$ is stationary. Critical values are 0.739 for a 1% significance level and 0.463 for a 5% significance leve

### *2.5.4. Time varying Fractional Integration: Assessing Hypothesis 1*

Table 2.3 summarises the distributions of the estimated time-varying parameter *d* for each spot market, which are plotted in Figure 2.3 from the earliest available starting date. The mean of the estimated *ds* are consistent with the reported estimates based on ELW and FELW over the entire sample. For instance in Table 2.3, the mean of the estimated *ds*, reported in the first column, is equal to 0.715 for Belpex. This is of a similar magnitude as the estimated order of integration obtained over the whole sample (Table 2.1), which was equal to 0.662 (ELW) or 0.650 (FELW). Furthermore, whole sample estimates are included in the 95% confidence intervals for the mean order of integration *d,* which are reported in parentheses in Table 2.3. Values between 0.5 and 1 mean that spot price series are fractionally integrated but mean-reverting. APX-UK prices have with the lowest mean average estimate for *d* (0.583), thus showing the fastest speed of reversion to the mean. Such a low *d* could reflect a large share of flexible gas-based generation (46.2% in 2010) in its electricity mix (Eurostat, 2013a), which has shorter ramping times, or, in comparison to other spot markets in the period studied, its shorter settlement periods and gate closure nearer to delivery. Other markets have order of integration varying between 0.643 (EPEX-DE) and 0.913 (Nordpool). The highest value suggests a trend in the time series, which may be explained by the large share of hydro-based capacity, which makes electricity prices in the Nordpool dependent on hydrological conditions (Botterund et al., 2010). E.g. the maximum observed value, reported in column three, is 1.735, which occurred during a 'power drought' in 2002, when Norway witnessed its driest summer in 70 years and available reserve capacity was below critical levels (Dooley, 2002). The minimum order of integration, *d*, in the fourth column, corresponds to APX-UK (0.243). All markets, except Nordpool, exhibit periods during which the order of integration, *d*, is below the critical value of 0.5, which are periods when the time series are invertible. But spot markets also show periods during which the estimated order of integration is greater than unity, which is indicative of non-stationary behaviour. The exceptions are OTE and EPEX-DE, which have consistently stationary prices. As a whole, estimates of *d* are similar to those reported by Pellini (2012). Still, there are differences, e.g. for the *d* estimates in APX-UK and Belpex prices, which could be due to sampling variation since Pellini´s (2012) data does not cover the last 10 months in this study.

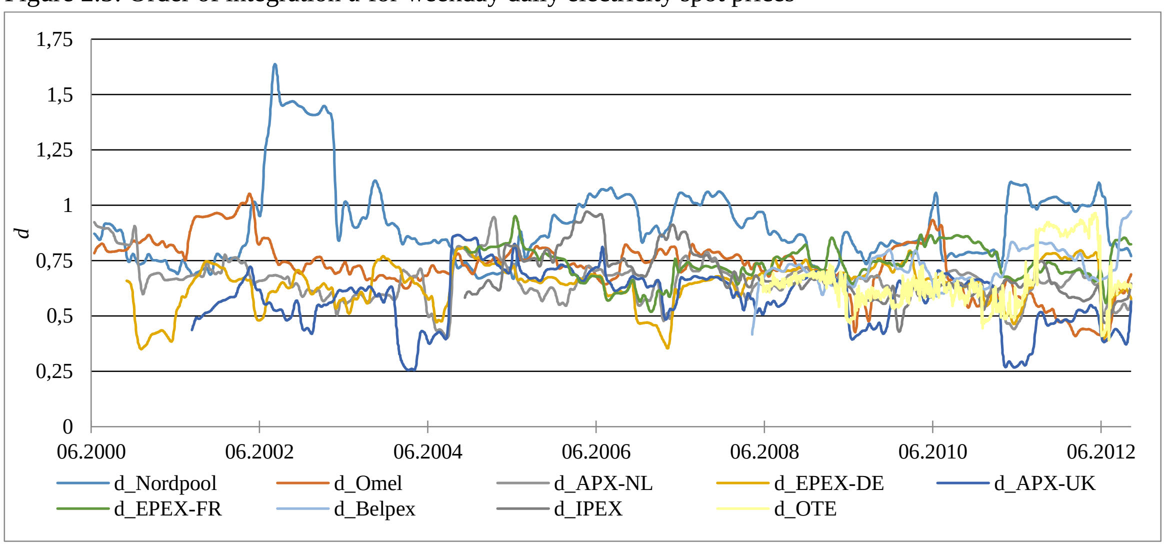
These findings together with Table 2.3 and Figure 2.3 highlight the time-varying nature of the spot price series. This study's approach to examining electricity market integration in the EU through rolling windows is therefore justified and contributes to the literature.

Table 4.3: Summary statistics for the order of integration d for electricity spot price series

| | **Mean** | **Median** | **Max.** | **Min.** | **Std. Dev.** | **Skew.** | **Kurt.** | **Obs.** |
|---|---|---|---|---|---|---|---|---|
| APX-NL | 0.658 [.525; .791] | 0.662 | 1.032 | 0.384 | 0.094 | 0.268 | 4.071 | 3215 |
| APX-UK | 0.583[.450; .716] | 0.611 | 1.085 | 0.243 | 0.130 | -0.378 | 3.100 | 2913 |
| BELPEX | 0.715 [.582; .848] | 0.702 | 1.124 | 0.382 | 0.084 | 0.466 | 4.070 | 1176 |
| EPEX-DE | 0.643 [.510; .776] | 0.659 | 0.922 | 0.292 | 0.101 | -0.831 | 3.423 | 3115 |
| EPEX-FR | 0.736 [.602; .869] | 0.733 | 1.044 | 0.498 | 0.084 | -0.139 | 2.997 | 2067 |
| IPEX | 0.677 [.543; .810] | 0.651 | 1.026 | 0.426 | 0.111 | 0.735 | 3.228 | 2126 |
| Nordpool | 0.913 [.779;1.046] | 0.868 | 1.735 | 0.591 | 0.186 | 1.459 | 5.450 | 3215 |
| OMEL | 0.724 [.590; .857] | 0.733 | 1.114 | 0.370 | 0.124 | -0.367 | 3.522 | 3215 |
| OTE | 0.658 [.524; .791] | 0.636 | 0.966 | 0.391 | 0.125 | 0.846 | 3.098 | 1149 |

Summary statistics for the order of integration *d* of electricity spot prices, estimated with FELW, window size *w*=200 and bandwidth *m*=54.

Figure 2.3: Order of integration *d* for weekday daily electricity spot prices




Concerning month-ahead prices, the estimates of the order of integration are plotted in Figure 2.4 and their distribution is summarised in Table 2.4. Mean average values (from 1.02 to 1.06) confirm our previous observations based on the whole sample: forward prices in the period studied are non-stationary. It is noteworthy that this finding could be linked to price expectations, which rely on the cost of generation and correlate forward prices with energy commodity prices (coal and gas), as discussed in the literature (e.g. Douglas and Popova, 2008; Bloys van Treslong and Huisman, 2010).

Figure 2.4: Order of integration *d* for electricity weekday daily month-ahead prices

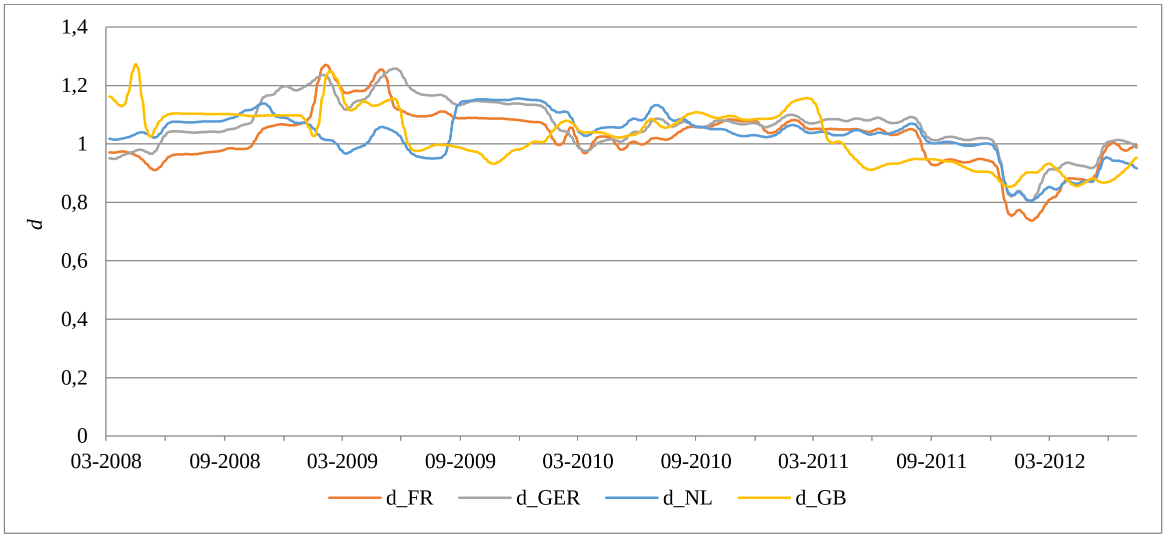



Table 5.4: Summary statistics for the order of integration d for one-month ahead electricity price

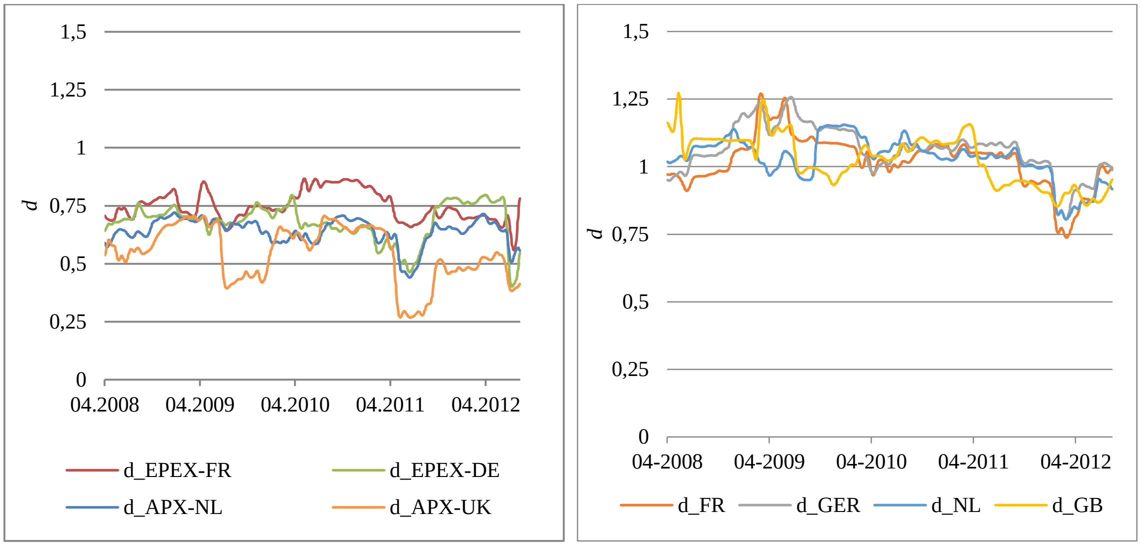
| | Mean | Median | Max. | Min. | Std. Dev. | Skew. | Kurt. |
|---|---|---|---|---|---|---|---|
| FR | 1.020 [.887; 1.153] | 1.040 | 1.463 | 0.718 | 0.099 | -0.349 | 4.397 |
| GB | 1.027 [.894; 1.160] | 1.036 | 1.472 | 0.828 | 0.096 | 0.174 | 2.993 |
| GER | 1.064 ; [.930; 1.197] | 1.068 | 1.275 | 0.782 | 0.091 | -0.397 | 3.504 |
| NL | 1.032 [.8986; 1.165] | 1.040 | 1.168 | 0.779 | 0.081 | -0.897 | 3.734 |

Summary statistics for the order of integration *d* of one-month ahead electricity prices, estimated with FELW, window size *w*= 200 and bandwidth *m*=54.

### *2.5.5. Speed of Mean Reversion: Assessing Hypothesis 1*

Figure 2.5 shows forward and spot prices during the period from April 2008 to August 2012, when the time series overlap. It indicates that the ability of the electricity spot markets to overcome supply and demand shocks quickly did not increase, because as there is no significant negative downward trend in the estimates of the order of integration (Eq. 3). Hence, there is no support for hypothesis 1. For forward markets, however, a statistically significant (1% level) downward slope may be seen in Figure 2.5, whose estimates range from -0.00012 (France) to -0.0002 (GB). In summary, electricity one-month-ahead markets have become more resilient to shocks, whereas spot day-ahead markets have not.

Figure 2.5: Comparison of orders of time-variant integration *d* between electricity spot and forward markets between April 2008 and August 2012.




### 2.5.6. *Time Varying Fractional Cointegration: Assessing Hypothesis 2a*

Prices in liberalised electricity markets are expected to converge as markets integrate. However, in the spot markets, the cointegrating relationships vary, as summarised in Table 2.5, in which the percentage of days of fractional cointegration with directly connected market pairs are reported. P-values obtained from tests of differences in proportion are shown in the last column. The periods before and after the trilateral market coupling, which occurred on 21 November 2006, are compared. For four spot markets (Nordpool and APX-NL, EPEX-FR and EPEX-DE, EPEX-FR and OMEL, as well as EPEX-FR and APX-UK), the observed change is not as hypothesised: there was less or no change in convergence. However, for three market pairs (Nordpool and EPEX-DE, APX-NL and EPEX-DE, EPEX-FR and IPEX), we find an increase in convergence at 5% significance level. This result differs from Pellini's (2012) which only supported convergence for APX-NL and EPEX-DE.

Considering average spot price dispersion before and after the TLC, as shown in columns five to seven of Table 2.5, one would expect price dispersion to decrease with increasing market integration. The p-values, in column seven, confirm lower price dispersions after the TLC for five market pairs

(APX-UK and APX-NL, Nordpool and APX-NL, APX-NL and EPEX-DE, EPEX-FR and EPEX-DE as well as EPEX-FR and IPEX). The expectations of cointegrated prices and decreasing price dispersion were supported by (APX-UK, APX-NL), (APX-NL, EPEX-DE) and (EPEX-FR, IPEX). However, for one market pair (EPEX-FR and OMEL) there was no decrease in price dispersion and for two pairs (Nordpool and EPEX-DE; EPEX-FR and APX-UK) an increase was observed. Overall, results are mixed and we lack full support for hypothesis 2, i.e.: EU electricity spot markets are not becoming increasingly integrated.

Table 6.5: Percentage of time of fractional cointegration and average price dispersion before and after TLC spot markets

| | **Fractional Cointegration** | | | **Average price dispersion** | | |
|---|---|---|---|---|---|---|
| **Market Pair** | **Before TLC** | **After TLC** | **p-value** | **Before TLC** | **After TLC** | **p-value** |
| APX-UK APX NL | 82% | 83% | 0.334 | 11.013 | 7.834 | 0.00001 |
| Nordpool APX-NL | 37.5% | 23.2% | - | 17.216 | 15.142 | 0.0002 |
| Nordpool EPEX-DE | 28% | 32.6% | 0.000 | 10.528 | 13.543 | - |
| APX-NL EPEX-DE | 78.9% | 89.9% | 0.000 | 10.180 | 3.786 | 0.00001 |
| EPEX-FR EPEX-DE | 85.7% | 70% | - | 5.779 | 4.829 | 0.0041 |
| EPEX-FR OMEL | 92.4% | 64.8% | - | 11.056 | 10.666 | 0.2277 |
| EPEX-FR IPEX | 43.5% | 47.9% | 0.042 | 23.831 | 22.133 | 0.0033 |
| EPEX-FR APX-UK | 90% | 40% | - | 8.466 | 8.985 | - |

Percentage of time of fractional cointegration between neighbouring or directly interconnected market pairs before and after 21 November 2006. P-value based on a one-sided test for proportions. Average price dispersion before and after 21 November 2006. P-value based on from a one-sided test for proportions.

By contrast, when we consider one-month-ahead prices, we find significant increases in convergence, as reported in Table 2.6. For example, periods of fractional cointegration between the German and Dutch markets increased by 30%. For all market pairs, we find significant decreases in price dispersion, as reported in columns five to seven of Table 2.6. Hence, price convergence is supported, and hypothesis 2a is not rejected in the case of forward markets. This may tally with the view that long term capacity auctions enable optimal coupling in forward electricity markets.

Table 7.6: Percentage of time of fractional cointegration and average price dispersion before and after 20 January 2010 forward prices

| | Fractional Cointegration | | | Average price dispersion | | |
|---|---|---|---|---|---|---|
| | **Before** | **After** | **p-value** | **Before** | **After** | **p-value** |
| FR_GER | 97% | 100% | 0.000 | 6.825 | 2.964 | .0001 |
| GER-NL | 67% | 100% | 0.000 | 2.365 | 1.384 | .0001 |
| NL-GB | 65.5% | 96.6% | 0.000 | 13.038 | 3.996 | .0001 |
| FR-GB | 74.2% | 98.7% | 0.000 | 15.325 | 5.151 | .0001 |

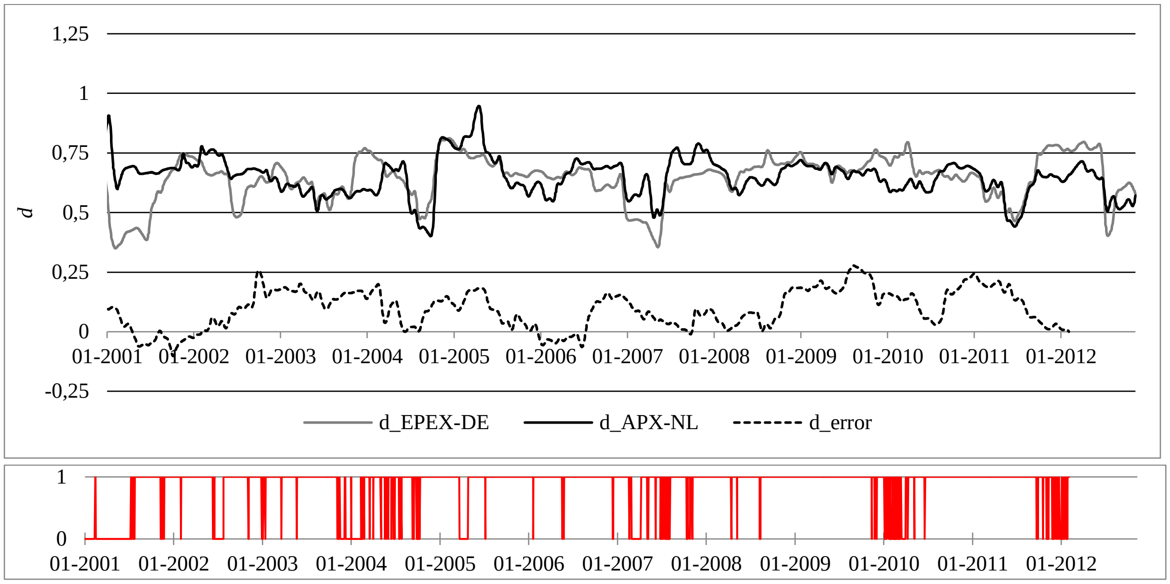
Percentage of time of fractional cointegration between neighbouring or directly interconnected market pairs before and after 20 January 2010. P-value based on a one-sided test for proportions. Average price dispersion before and after 20 January 2010. P-value based on a one-sided test for proportions.

The rejection of hypothesis 2a by some spot markets indicates that there are other factors that influence price convergence and divergence. Figures 2.6 to 2.21 illustrate the time-dependency of the order of integration $d$ for neighbouring electricity spot and forward price series in more detail. The grey and black lines show the smoothed rolling window estimates of the order of integration of the two respective price series, which should not be significantly different. In addition, the dotted line shows the order of integration of the error correction term ($z_t$ of equation 2), which should be lower than those of the original price series for the two markets to be integrated. In the lower part of Figures 2.6 to 2.21, it is indicated when these conditions hold and the two price series are cointegrated, and also when the conditions are violated and cointegration is rejected. We will now consider different pairs of neighbouring countries and assess the impact of some noticeable developments in their electricity markets.

#### *2.5.6.1. Germany and The Netherlands*

Figure 2.6 shows that, from July 2000 to March 2013, electricity spot prices in EPEX-DE and APX-NL were integrated 84% of the period, and confirms previous observations made by Zachmann (2008) on data from 2002 to 2006. Integration appears to have stabilised over time, except for two periods of accumulated breakdowns during the winter of 2010 and 2012, which were on average colder and characterised by higher residential demand. According to Eurostat (2013b), there were 36 more heating degree days (HDD) in each month of the first quarter of 2010 compared to the same period of 2009.[2] The first two weeks of February 2012 were extremely cold and electricity consumption in the EU-27 grew by 5.1% compared to the same month in the previous year (European Commission, 2010a; European Commission, 2012c).

Figure 2.6: EPEX-DE & APX-NL

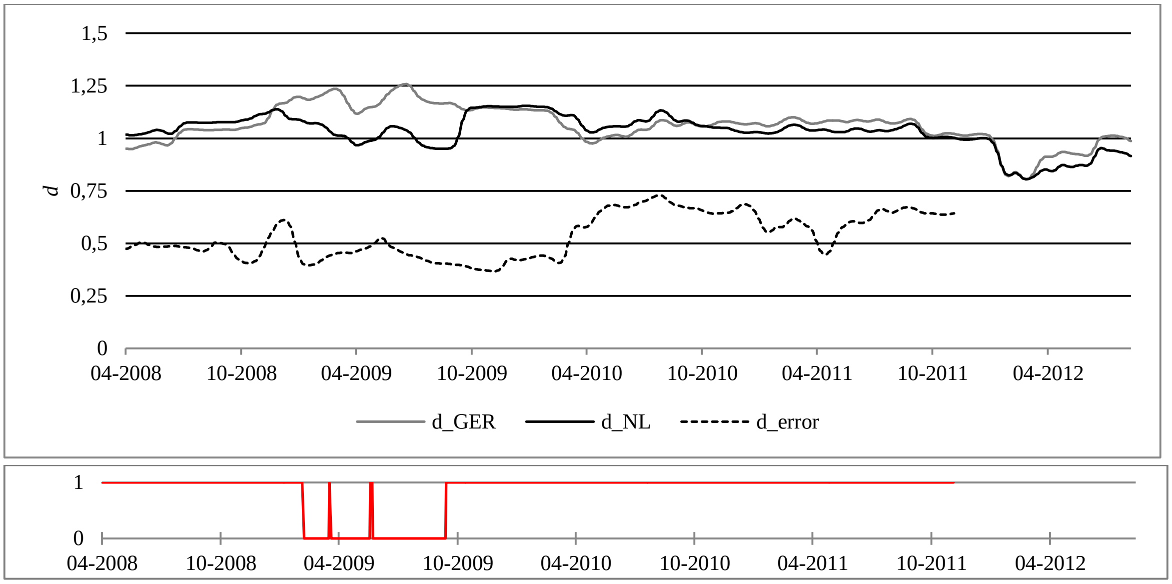



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Month-ahead electricity price series were also fractionally cointegrated for 84% of the time between April 2008 and November 2011, although there was a period of divergence in 2009, as shown in Figure 2.7. This divergence reflects higher estimates of *d* for German month-ahead prices, which might have been associated with the introduction of the German EEG law (*Erneuerbare Energien Gesetz*) on 1 January 2009 that prioritises the dispatch of electricity generated by renewables.

[2] HDDs are defined relative to the outdoor temperature. On days when the daily average outdoor temperature is below 21°C, HDD values are in the range of positive numbers; otherwise HDD equals zero (European Commission, 2012b).

Figure 2.7: German & Dutch one-month-ahead prices

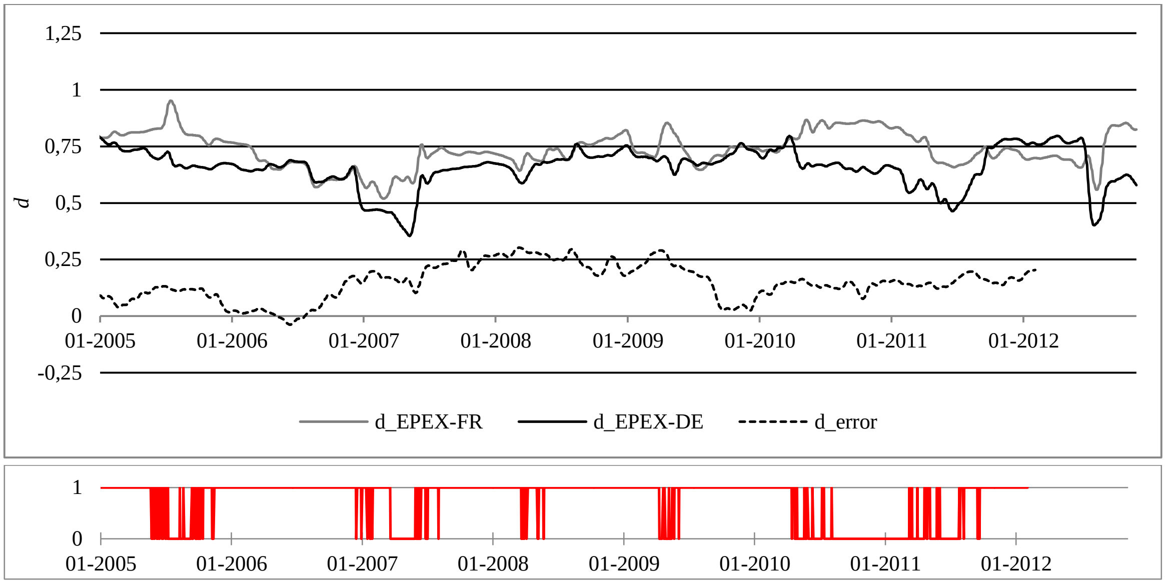



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

#### *2.5.6.2. France and Germany*

From January 2005 to January 2012, EPEX-DE and EPEX-FR were integrated for almost 75% of the period, as illustrated in Figure 2.8. This finding confirms previous observations in literature (e.g. Bosco et al., 2010; Pellini, 2012; Zachmann, 2008) of a strong association between the two largest European markets. However, periods of divergence are also identified, for which there are several possible explanations. First, in the summer of 2010, exceptionally high temperatures increased the demand for cooling and river temperatures, so that some French nuclear power plants could not rely on these rivers for cooling and became unavailable. Second, in the winter of 2010, the German supply side was affected by unplanned nuclear plant outages (Gundremmingen-B in the first half of November, Biblis-B in December). Moreover, a wave of strikes in France reduced the generation of nuclear plants (European Commission, 2010c).

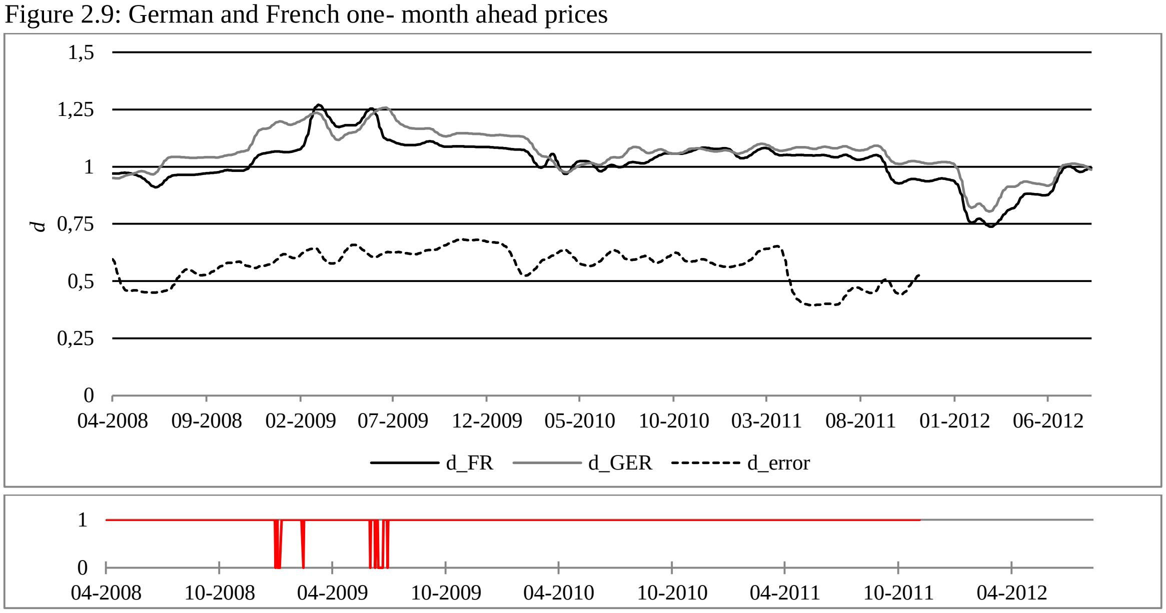
Figure 2.8: EPEX-FR and EPEX-DE




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

French and German forward markets were cointegrated 98.5% of the time, as depicted in Figure 2.9. There are only a few days in June and July 2009, when the cointegrating relationship broke down, possibly due to concerns of imminent strikes in the French power sector (European Commission, 2009).

Figure 2.9: German and French one- month ahead prices

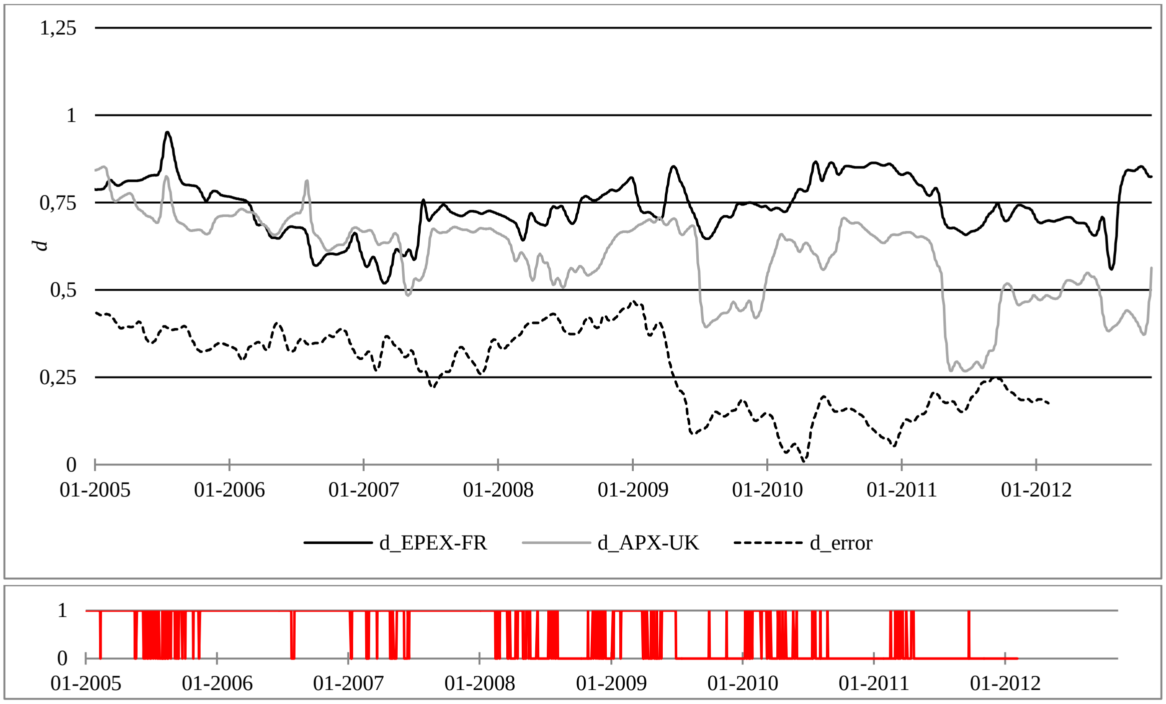



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

*2.5.6.3. GB and France*

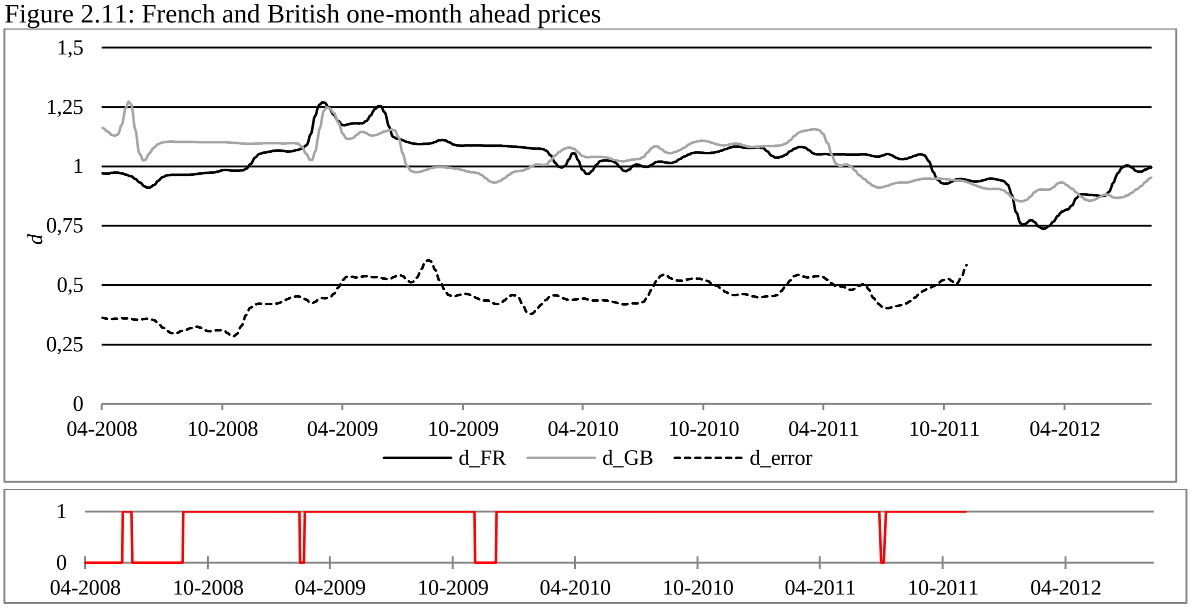
The British and French markets have been interconnected since the 1960s and were cointegrated during half of the period studied (November 2004 to November 2011). Figure 2.10 shows a tendency towards less cointegration in the spot markets. Forward markets are cointegrated between April 2008 and November 2011 (85% of the period), as shown in Figure 2.11.

Figure 2.10: EPEX-FR and APX-UK




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Figure 2.11: French and British one-month ahead prices

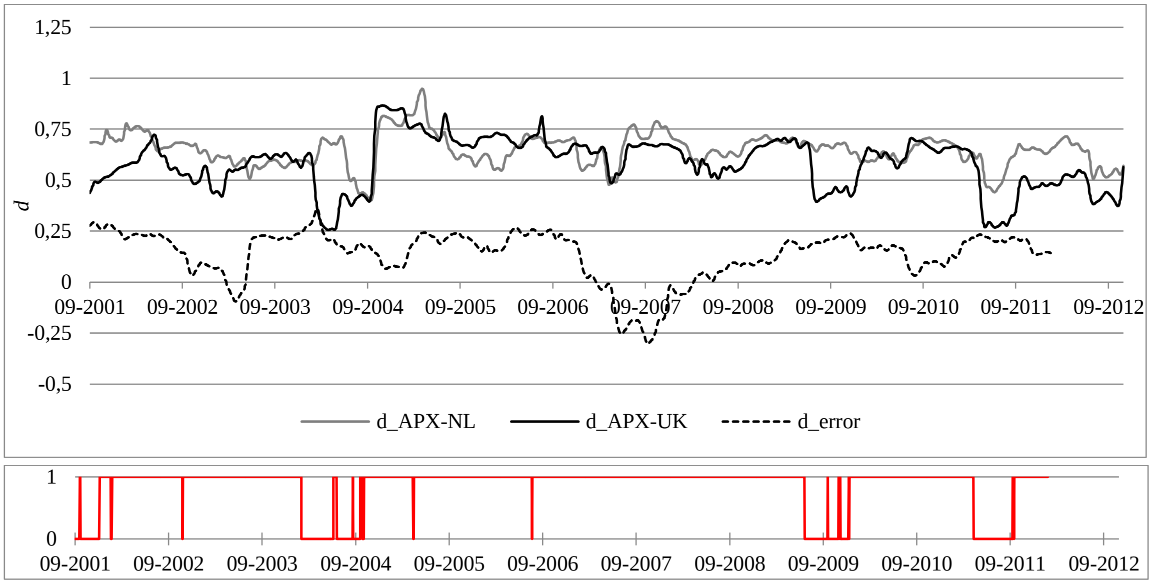



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

### *2.5.6.4. GB and The Netherlands*

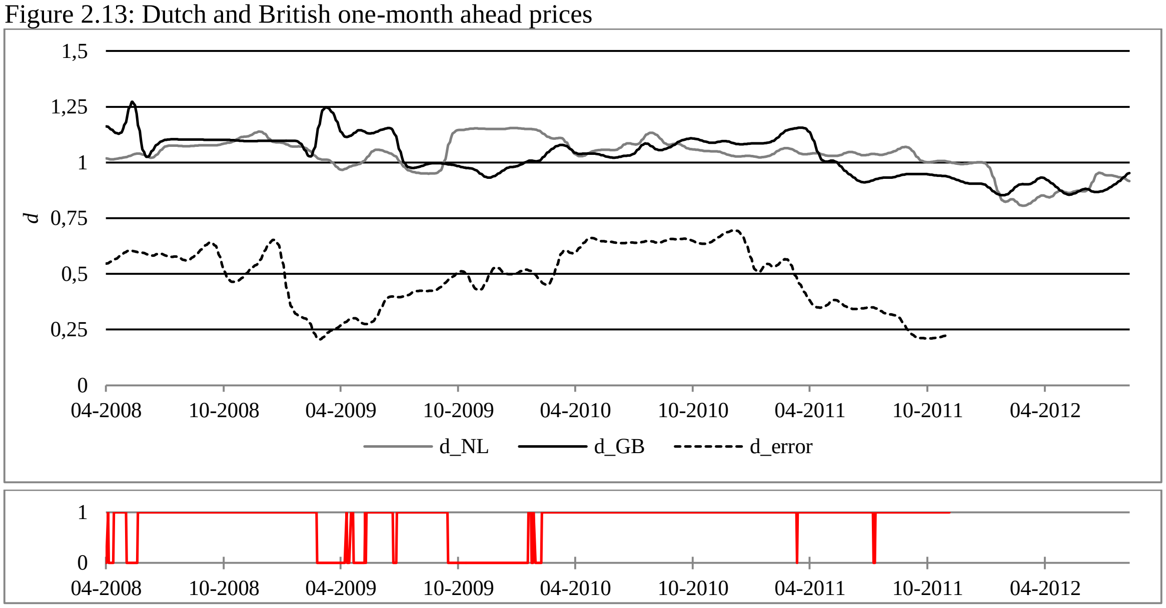
Figure 2.12 shows that APX-NL and APX-UK, are cointegrated during 83% of the period (January 2005 to January 2012), thus confirming previous findings (e.g. Pellini, 2012). Similarly, Figure 2.13 indicates that the Dutch and British one-month-ahead prices converged for 82% of the days between April 2008 and November 2011.

Figure 2.12: APX-NL and APX-UK




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Figure 2.13: Dutch and British one-month ahead prices




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

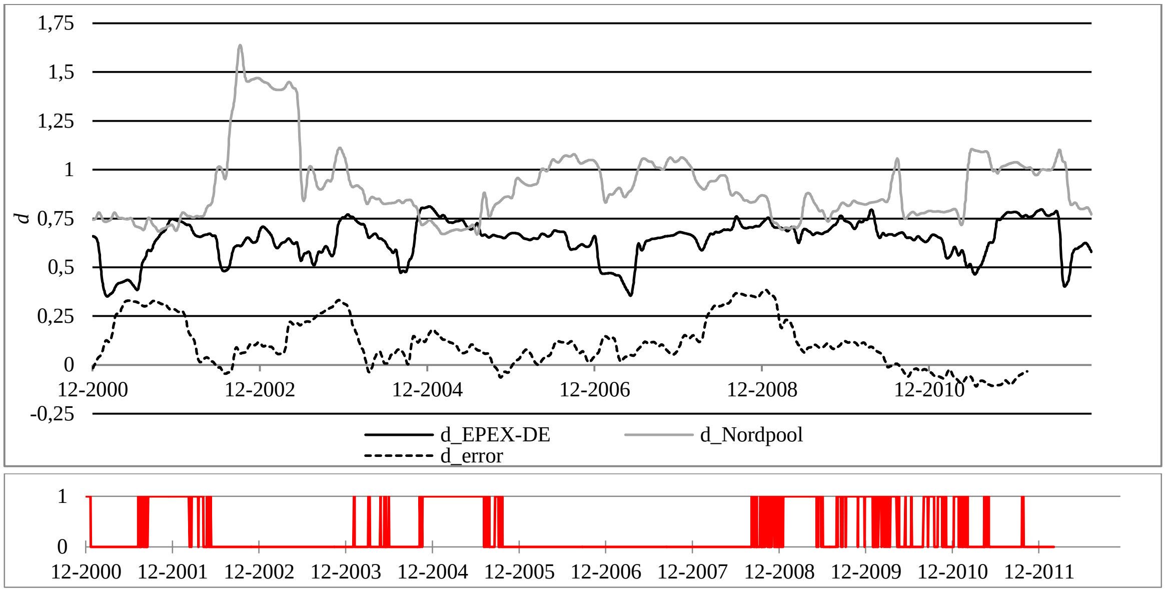
Both figures indicate a period of divergence in 2009. The significantly lower value for *d* in APX-UK, as shown in Figure 2.12, may reflect the competitiveness of gas and the clean spark spread in

2009. Divergence between the British and the Dutch markets in 2010 may be due to failures of the NorNed interconnector at the beginning of February (European Commission, 2010a). Another drop in the order of integration *d* of British one-month ahead prices can be observed in the 2nd quarter of 2011, which might have been due to a public holiday (29th of August) and gas prices that increased following maintenance work on gasification facilities in Quartar plus fears of a growing demand from Japan in the aftermath of the events in Fukushima. (European Commission, 2011d). These observations, however, were not reflected in the forward market.

#### *2.5.6.5. Nordpool with Germany and The Netherlands*

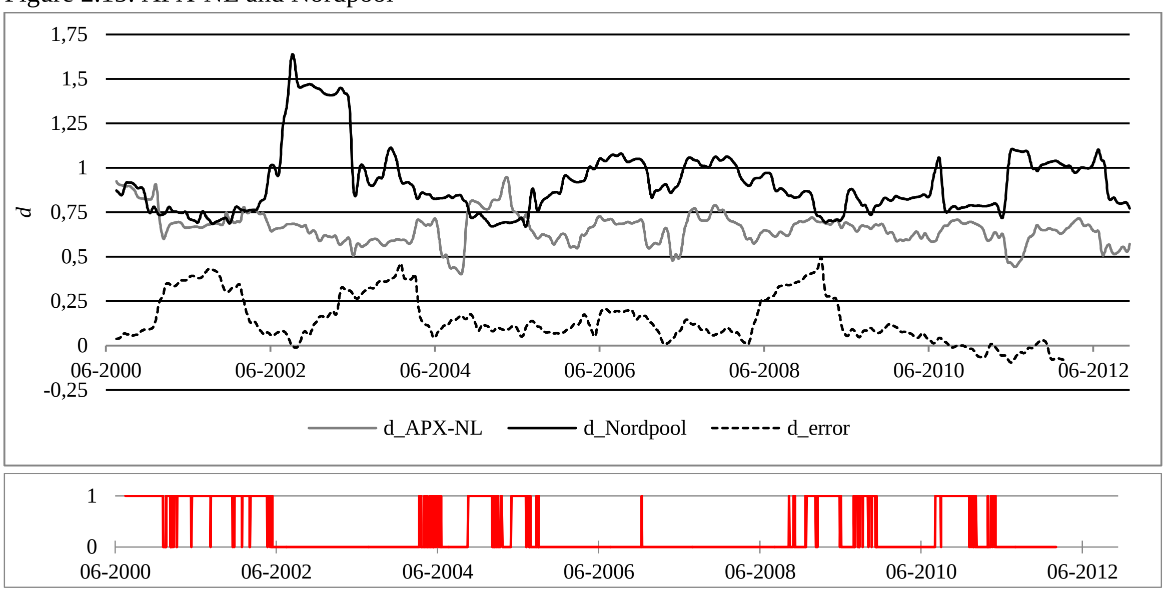
Cointegration between the Nordpool and adjacent markets was low: only 28% of days with EPEX-DE and 31% with APX-NL, as seen in Figures 2.14 and 2.15, respectively. However, from the second half of 2008, after a long period of divergence, there was an increase in cointegrated days, which might follow the commissioning of NorNed interconnector on 6 May 2008 (Tennet, 2013).

Figure 2.14: EPEX-DE and Nordpool




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Figure 2.15: APX-NL and Nordpool

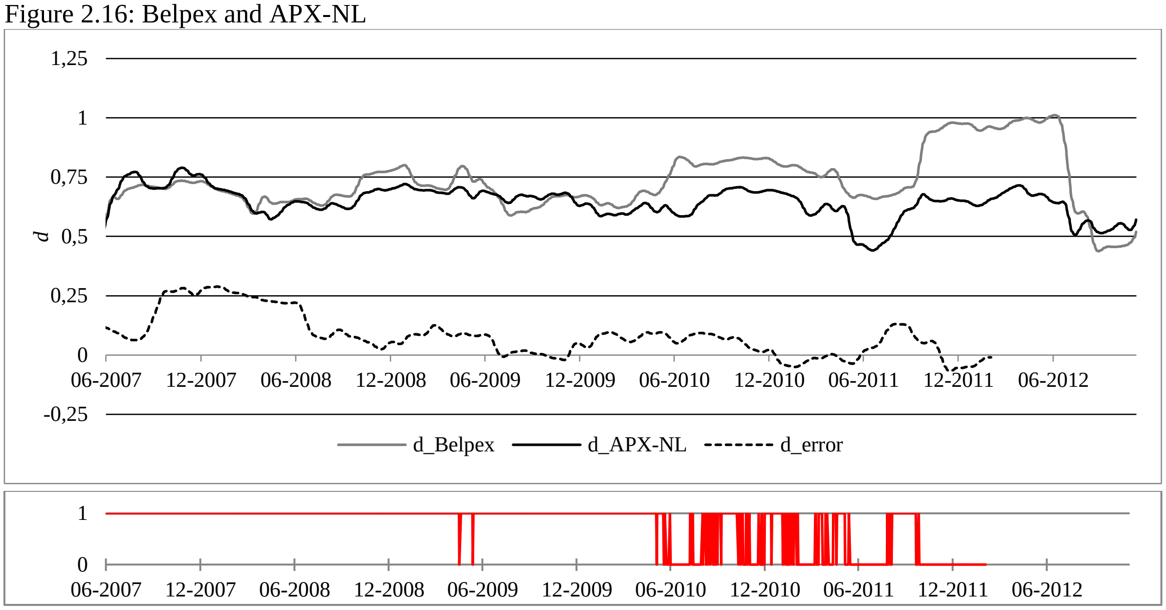



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

#### *2.5.6.6. Belgium with France, The Netherlands and Germany*

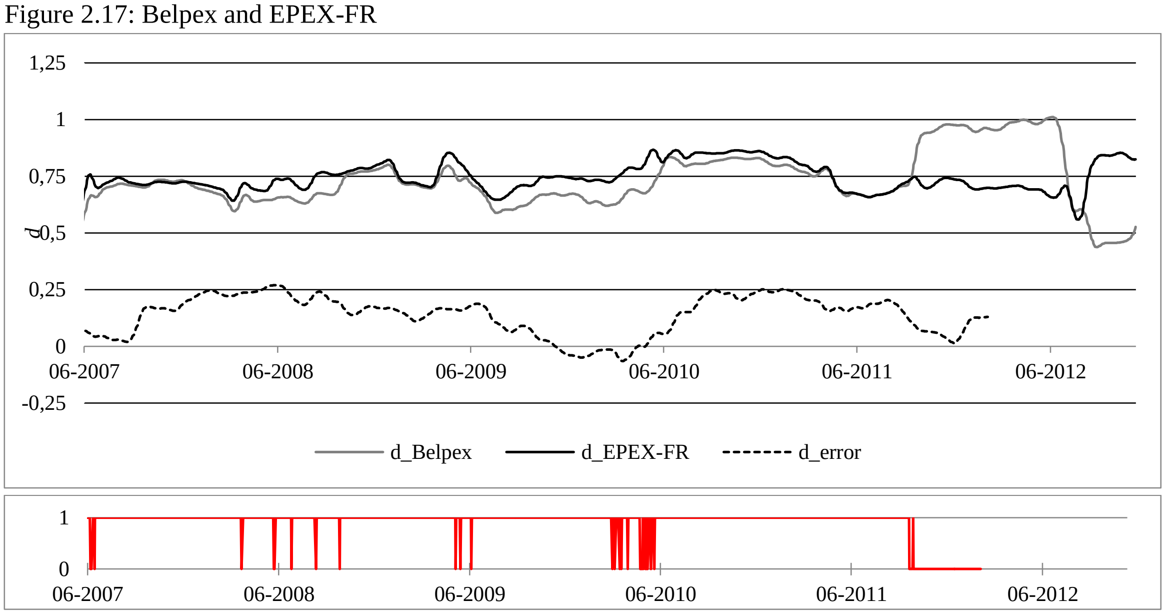
The TLC between Belgium, France and The Netherlands started in November 2006. Figures 2.16 and 2.17 illustrate that, since then, the orders of integration of spot prices are not significantly different in Belpex and EPEX-FR (fractionally cointegrated 90% of the time) as well as Belpex and APX-NL (fractionally cointegrated 76% of the time). Figure 2.17 shows that EPEX-FR and Belpex electricity spot prices share strong common price dynamics, with few exceptions occurring mainly in winter and spring. These results confirm previous findings of a high convergence between Belpex and EPEX-FR was (e.g. Autran, 2012; Pellini; 2012). Divergences can be observed in the period from 2010 to 2011 between the Dutch and the Belgian markets, which might reflect imports from the German system, which had a larger production of wind power in the period (Öko Institut, 2013; Weigt et al. 2010). Figure 2.18 shows that German and Belgian electricity spot prices were continuously fractionally cointegrated until June 2010.

Figure 2.16: Belpex and APX-NL



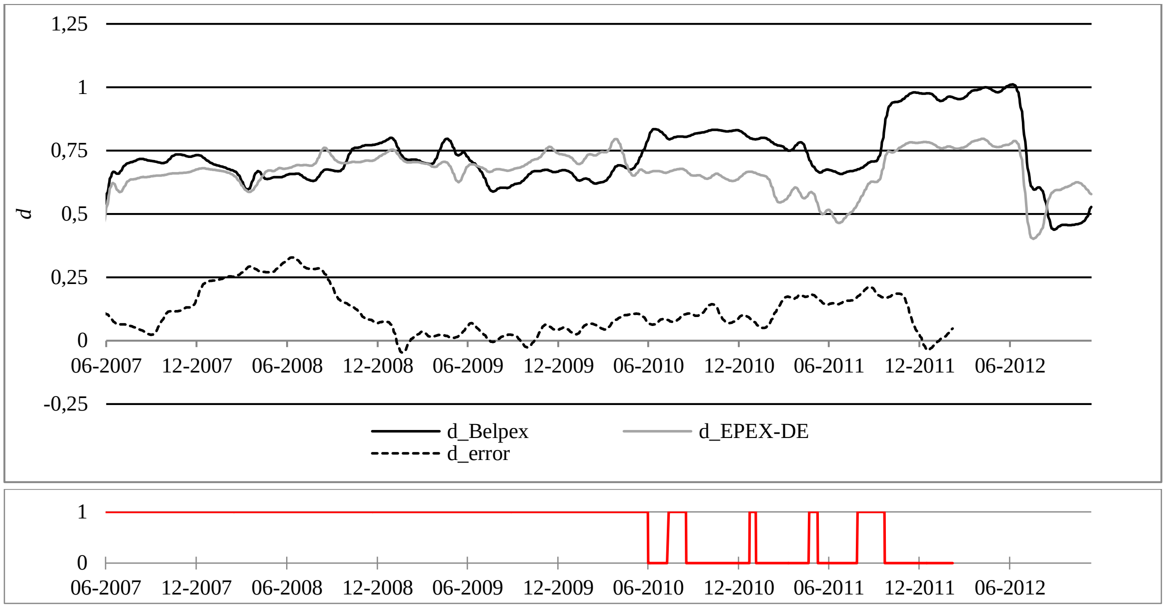

Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Figure 2.17: Belpex and EPEX-FR




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Figure 2.18: Belpex and EPEX-DE

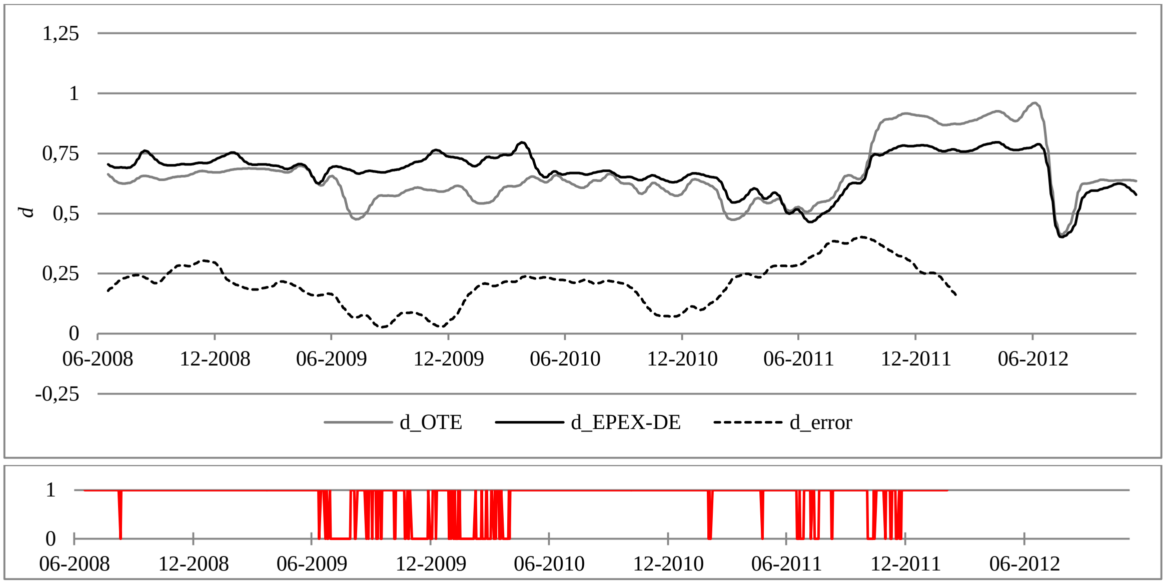



Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

#### *2.5.6.7. The Czech Republic and Germany*

Figure 2.19 illustrates that German and Czech electricity spot prices were fractionally cointegrated during 84% of the period between June 2008 and March 2011. From the second half of 2009 until the first quarter of 2010, frequent deviations from common long run dynamics between the Czech and German electricity spot prices can be observed. This development may reflect the new law (*EEG*) leading to negative prices in the German spot market (European Commission, 2010b). Another cluster of brief periods of no fractional cointegration can be found in the third and fourth quarters of 2011. Unusual events such as the cancellation of daily auctions in mid-October, as well as two holidays (Czech Independence Day and All Saints) affected Czech prices in the fourth quarter 2011. Furthermore, slightly colder than normal weather conditions led to an increase in the demand for electricity thus creating an upward pressure on spot prices in the region (European Commission, 2011d), which might have contributed to the observed divergences.

Figure 2.19: OTE and EPEX-DE



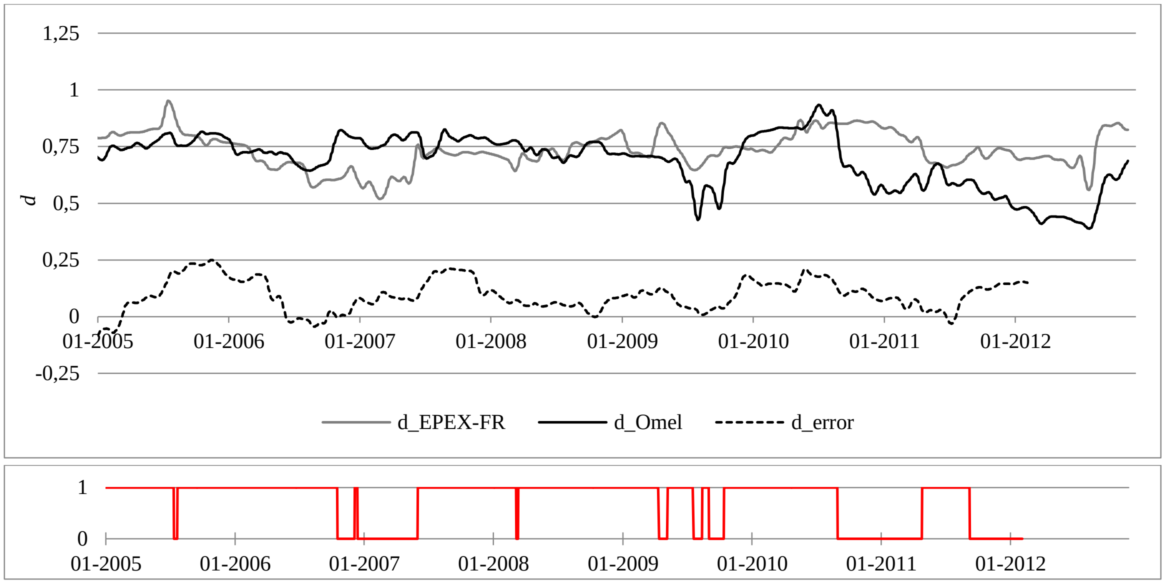

Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

#### *2.5.6.8. France with Italy and Spain*

According to Figure 2.20, OMEL and French market EPEX-FR were fractionally cointegrated during 72% of the days in the period between December 2004 and February 2012, which is consistent with Zachmann's (2008) and Pellini's (2012) assessments of more frequent convergence than divergence.

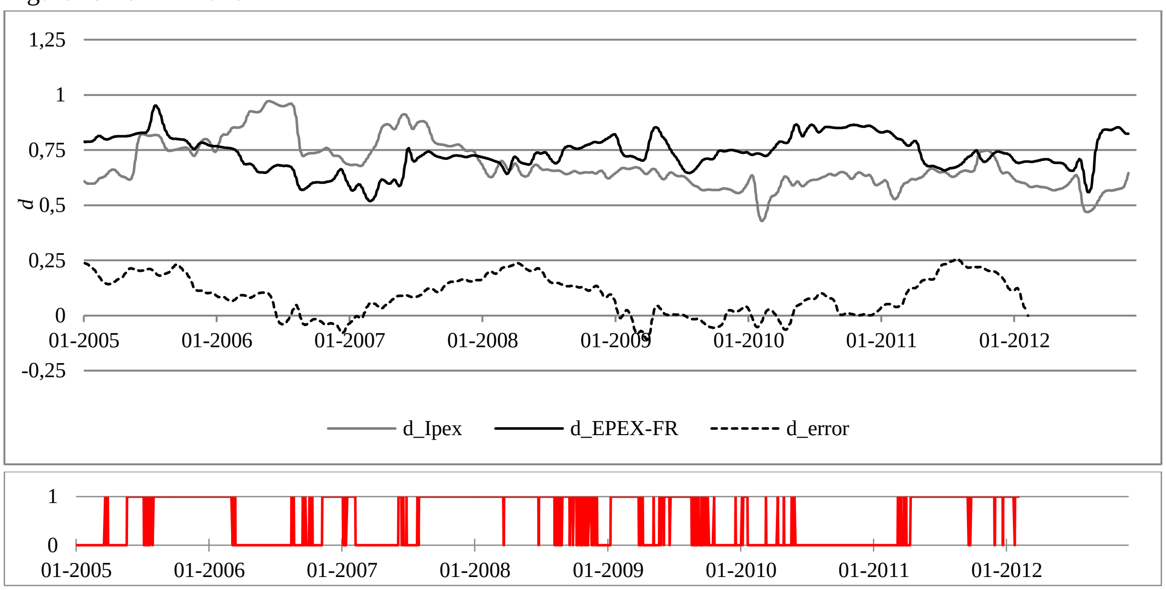
Deviations may be due to increasing shares of intermittent wind power and limited net transfer capacity between OMEL and EPEX-FR, which ranged from 500 to 600MW from 2006 to 2011, which is significantly lower than between Belpex and EPEX-FR (2300 to 3400MW). French and Spanish electricity spot prices de-coupled in the first quarter of 2011, when fewer nuclear power plants were available because of outages and maintenance (European Commission, 2011a). Figure 2.21, illustrates that IPEX and EPEX-FR share common long run dynamics during only 50% of the period.

Figure 2.20: EPEX-FR and OMEL




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

Figure 2.21: IPEX and EPEX-FR




Time-varying fractional cointegration estimates (top); periods of cointegration (1) versus periods of no cointegration (0).

### *2.5.7. Periods of Fractional Cointegration in Spot versus Forward Markets: Assessing Hypothesis 2b*

When comparing the proportion of days of fractional cointegration in forward and spot markets, Table 2.7 shows that for two out of three market pairs, integration was significantly higher in forward markets between November 2007 and November 2011. The cointegration relationship between French and German month-ahead prices was stable (98.5% of fractional cointegration). In contrast, cointegration between their spot markets was the least frequent (67.3%). A similar pattern was observed in other pairs (British & Dutch or French). However, for Germany and The Netherlands convergence was more frequent in the spot market compared to the forward market. We therefore reject hypothesis 2b, which stated greater convergence in the forward compared to the spot market and confirm previous findings in the literature (Bunn and Gianfreda, 2010) which were judged to reflect market maturity as well as low liquidity in the forward market compared to the spot.

Table 8.7: Comparison of periods of fractional cointegration between spot and forward markets

| **Market Pair** | **Integration in spot market** | **Integration in forward market** | **p-value** |
|---|---|---|---|
| FR-GER | 67.3% | 98.5% | 0.000 |
| GER-NL | 94.2% | 83.8% | - |
| NL-GB | 78.1% | 82% | 0.038 |
| FR-GB | 28% | 86.5% | 0.000 |

Comparison of periods of fractional cointegration between spot and forward markets between November 2007 and November 2011. P-value based on one-sided t-test.

### *2.5.8. Special Events and Mean Reversion: Assessing Hypothesis 3*

#### *2.5.8.1. Interconnector: Assessing Hypotheses 3a and 3b*

The NorNed, which has a capacity of 700MW, connects Feda in Norway and Eemshaven in The Netherlands and has been in operation since 6 May 2008. As shown in Table 2.8, one year after the launch of the NorNed interconnector, the parameter *d* had decreased significantly (5% significance level) for Nordpool from 0.9693 to 0.8421. However, there is no statistically significant change in the order of integration for APX-NL, Belpex or EPEX-DE.

Table 9.8: Order of integration d before and after commissioning of NorNed interconnector

| | | $\bar{d}$ *and CI* | t-statistics |
|---|---|---|---|
| **APX-NL** | d_before | 0.6824 [.549; .8158] | 0.298 |
| | d_after | 0.7027 [.5693; .8361] | |
| **Nordpool** | d_before | 0.9693[.8359; 1.1027] | -1.869* |
| | d_after | 0.8421 [.7087; .9754] | |
| Belpex | d_before | 0.7644 [.6310; .8978] | 0.000 |
| | d_after | 0.7646 [.6312; .8980] | |
| EPEX-DE | d_before | 0.6457 [.5124; .7791] | 0.527 |
| | d_after | 0.7160 [.5827;.8494] | |

NorNed interconnector order of integration *d* for one year before and one year after the commissioning of the NorNed (06.05.2008). Observations *n*=260, window size *w*=200, bandwidth *m*=54 and iterations *i*=100. The asterisks * and ** denote a 5% and 1% significance level, respectively. Critical values for the one-sided test are 5%= 1.645 and 1%=2.326, and for the two-sided test 5%= 1.960 and 1%= 2.576. Markets directly affected by the policy (one-tailed test) are printed in bold.

Similarly, Table 2.9 considers the potential effect of the introduction of the BritNed interconnector, which links GB (Isle of Grain) and The Netherlands (Rotterdam), since 1 April 2011 (BritNed, 2013). The order of integration in the British (APX-UK) spot prices, $d_{before}$ (0.6294) is significantly (1% significance level) larger than after interconnection, $d_{after}$ (0.3316). However, there is no statistically significant change in the order of integration *d* in the Dutch electricity spot market, Belpex, EPEX-FR or EPEX-DE.

Table 10.9: Order of integration d before and after commissioning of the BritNed interconnector

| | | $\bar{d}$ and CI | t-statistic |
|---|---|---|---|
| **APX-NL** | d_before | 0.6859 [.5525; .81926] | 1.060 |
| | d_after | 0.7580 [.6246; .89136] | |
| **APX-UK** | d_before | 0.6294 [.496;.76276] | -4.377** |
| | d_after | 0.3316 [.19823;.465] | |
| Belpex | d_before | 0.8255 [.6921; .9589] | 1.056 |
| | d_after | 0.8974 [.764; 1.031] | |
| EPEX-FR | d_before | 0.8254 [.692; .9587] | 1.318 |
| | d_after | 0.9151 [.7817; 1.0485] | |
| EPEX-DE | d_before | 0.6404 [.5070; .7738] | 1.074 |
| | d_after | 0.7135 [.5801; .8469] | |

BritNed interconnector order of integration *d* for one year before and one year after the commissioning of the BritNed (01.04.2011). Observations *n*=260, window size *w*=200, bandwidth *m*=54 and iterations *i*=100. The asterisks * and ** denote a 5% and 1% significance level, respectively. Critical values for the one-sided test are 5%= 1.645 and 1%=2.326, and for the two-sided test 5%= 1.960 and 1%= 2.576. Markets directly affected by the policy (one-tailed test) are printed in bold.

Overall, we find mixed evidence for Hypotheses 3a and 3b regarding the increasing speed of mean reversion after the commissioning of an interconnector for directly affected markets. However, changes in the speed of mean reversion appear to depend on the level of interconnection before the commissioning of an interconnector achieved.

#### *2.5.8.2. Market Coupling: Assessing Hypotheses 3a and 3b*

On 21 November 2006, Belgium, France and The Netherlands coupled their day-ahead (spot) electricity markets through their national power exchanges and transmission system operators (TSO) to the TLC (Belpex, 2012). Similar to Autran (2012), who identified (but not formally tested) a change in the level of mean reversion in spot prices as well as Nitsch et al. (2010) and De Jonghe et al. (2008), the results of this study show that since the TLC, the order of integration *d* decreased significantly. Table 2.10 shows that *d* changed significantly for EPEX-FR and APX-NL, which were part of the initiative, but also for IPEX and EPEX-DE, which were not. In the other neighbouring electricity markets, OMEL and APX-UK, no significant change in the estimates of the parameter $d$ was observed. Belpex has been excluded from the analysis because it started with the launch of TLC.

Table 11.10: Order of integration *d* before and after TLC

| | | $\bar{d}$ and $CI$ | t-statistics |
|---|---|---|---|
| **EPEX-FR** | d_before | 0.8036 [.6636;.9436] | -2.453** |
| | d_after | 0.6284 [.4884;.7684] | |
| **APX-NL** | d_before | 0.7597 [.6197,.8997] | -1.786 * |
| | d_after | 0.6321 [.4921, .7721] | |
| EPEX-DE | d_before | 0.7621 [.6221.;.9021] | -3.557** |
| | d_after | 0.5080 [.368;. 648] | |
| APX-UK | d_before | 0.6863[.5463; .8263] | 1.940 |
| | d_after | 0.5477 [.4077; .6877] | |
| OMEL | d_before | 0.8175 [.6775;.9575] | 1.468 |
| | d_after | 0.9223 [.7823;1.0623] | |
| IPEX | d_before | 0.965[.825;1.105] | -2.072* |
| | d_after | 0.817 [.677;. .957] | |

TLC order of integration *d* one year before and one year after the TLC (21.11.2006). Observations *n*=260, window size *w*=200, bandwidth *m*=54 and iterations *i*=100 and iterations=100. The asterisks * and ** denote a5% and 1% significance level, respectively. Critical values for the one-sided test are 5%= 1.645 and 1%=2.326, and for the two-sided test 5%= 1.960 and 1%= 2.576. Markets directly affected by the policy (one-tailed test) are printed in bold.

Nordic-German market coupling started on 9 November 2011. As shown in Table 2.11, in which the average order of integration during one year after and one year before market coupling are compared, a decrease in the order of integration of Nordpool spot prices can be noticed. Concerning the other markets, the long run spot price behaviour only changed in the French spot market, where a significant increase in the order of integration is observed in Table 2.11.

Table 12.11: Order of integration *d* before and after Nordic-German Market Coupling

| | | $\bar{d}$ *and CI* | t-statistic |
|---|---|---|---|
| **Nordpool** | d_before | 0.9648 [.8314; 1.098] | -1.900* |
| | d_after | 0.8355 [.7021; .9689] | |
| **EPEX-DE** | d_before | 0.6441 [.5107;.7776] | 1.008 |
| | d_after | 0.7127 [.5793; .8460] | |
| APX-NL | d_before | 0.7016 [.5682; .8335] | -0.667 |
| | d_after | 0.6562 [.5228; .7896] | |
| EPEX-FR | d_before | 0.7366 [.6032; .8700] | 3.208** |
| | d_after | 0.9549 [.8215; 1.0883] | |
| APX-UK | d_before | 0.6566 [.5232; .7900] | 0.976 |
| | d_after | 0.5902 [.4568; .7236] | |
| Belpex | d_before | 0.7463 [.6129; .8797] | 0.003 |
| | d_after | 0.7465 [.6131; .8799] | |

Order of integration *d* one year before and one year after the Nordic-German market coupling (09.11.2009). Observations *n*=260, window size *w*=200, bandwidth *m*=54 and iterations *i*=100. The asterisks * and ** denote a 5% and 1% significance level, respectively. Critical values for the one-sided test are 5%= 1.645 and 1%=2.326, and for the-two sided test 5%= 1.960 and 1%= 2.576. Markets directly affected by the policy (one-tailed test) are printed in bold.

On 9 November 2010, the Central Western European market coupling (CWE) expanded the TLC to Luxembourg and Germany (Belpex, 2012). Table 2.12 compares the order of integration before and after the event and shows significant changes in the estimates for *d* in EPEX-FR, APX-NL and EPEX-DE and, most noticeably, for spot prices in the three markets that were not directly addressed by the initiative (APX-UK, OMEL and OTE). For Belpex and IPEX prices, the reduction in the order of integration was insignificant.

Table 13.12: Order of integration *d* before and after CWE

| | | $\bar{d}$ *and CI* | t-statistic |
|---|---|---|---|
| **APX-NL** | d_before | 0.6570 [.5236; .7904] | -1.783* |
| | d_after | 0.5357 [.4023;.6691] | |
| **EPEX-FR** | d_before | 0.9559 [.8225; 1.0893] | -3.904** |
| | d_after | 0.6903 [.5569; .8237] | |
| **Belpex** | d_before | 0.7594 [.626; .8927] | -0.977 |
| | d_after | 0.6929 [.5595; .8263] | |
| **EPEX-DE** | d_before | 0.6723 [ .5389;.8957] | -2.514** |
| | d_after | 0.5012 [.3678; .6345] | |
| OMEL | d_before | 0.8007 [.6673;.9341] | 2.500* |
| | d_after | 0.6306 [.4972; .764] | |
| OTE | d_before | 0.6570 [.5236; .7904] | 2.790* |
| | d_after | 0.4672 [.3338; .6006] | |
| IPEX | d_before | 0.6228 [.4894;.7562] | 0.382 |
| | d_after | 0.5968[.4634; .7302] | |
| APX-UK | d_before | 0.5973 [.4639; .7307] | 3.201** |
| | d_after | 0.3794 [.246; .5128] | |

Order of integration *d* for one year before and one year after the CWE (09.11.10). Observations *n*=260, window size *w*=200, bandwidth *m*=54 and iterations *i*=100. The asterisks * and ** denote a 5% and 1% significance level, respectively. Critical values for the one-sided test are 5%= 1.645 and 1%=2.326, and for the two-sided test 5%= 1.960 and 1%= 2.576. Markets directly affected by the policy (one-tailed test) are printed in bold.

The above results are similar to those of reported by Castagneto-Gissey et al (2014), who found spot price correlation to increase after the CWE market coupling. However, considering all three market coupling events, there is mixed evidence regarding increases in speed of mean reversion after interconnection. Consequently, hypotheses 3a and 3b are not supported in our study.

#### *2.5.8.3. Germany's Energy Transition: Assessing Hypothesis 3c*

By 6 August 2011, a total of eight nuclear power plants, equalling a gross capacity of 8811MW or 40% of Germany's nuclear capacity, had been removed from the German electricity network within a six-month period (BDEW, 2011). As summarised in Table 2.13, the order of integration of the spot price series-*d* - increased for all markets directly linked to the German electricity market. We find support for hypothesis 3c, with the exception of IPEX. Besides the changes in the speed of mean reversion, the number of hours with negative prices have increased in Belpex, APX-NL, and EPEX-FR when we compare hourly data one year before with one year after the closure. For example, one year before the event only 8 hours had negative spot prices in EPEX-DE, but in the year after this figure increased to 26.

Table 14.13: Order of Integration d before and after Germany´s nuclear power plant closures

| | | $\bar{d}$ and $CI$ | t-statistic |
|---|---|---|---|
| **EPEX-DE** | d_before | 0.5914 [.458; .7281] | 2.130* |
| | d_after | 0.7363 [.6029; .8697] | |
| **EPEX-FR** | d_before | 0.7926 [.6592;.926] | 2.994** |
| | d_after | 0.9963 [.8629; 1.130] | |
| **APX-NL** | d_before | 0.6243 [.4909; .7577] | 4.225** |
| | d_after | 0.9118 [.7784; 1.045] | |
| **Belpex** | d_before | 0.7916 [.6582;.925] | 2.847** |
| | d_after | 0.9853 [.8519; 1.119] | |
| **Nordpool** | d_before | 0.7844 [.65104; .9177] | 1.708* |
| | d_after | 1.0122 [.8788; 1.1455] | |
| **OTE** | d_before | 0.4072 [.2738; .5406] | 6.736** |
| | d_after | 0.8655 [.7321; .9989] | |

Germany's nuclear phase-out order of integration *d* for one year before and one year after the German nuclear plant closure (06.08.2011). Observations $n$=260, window size $w$=200, bandwidth $m$=54 and iterations $i$=100. The asterisks * and ** denote a 5% and 1% significance level, respectively. Critical values for the one-sided test are 5%= 1.645 and 1%=2.326, and for the two-sided test 5%= 1.960 and 1%= 2.576. Markets directly affected by the policy (one-tailed test) are printed in bold.

### *2.6. Summary and Conclusion*

With the European Commission recently stating "It is time to complete the internal market for energy" (European Commission, 2012b), we are yet to know whether European electricity wholesale prices are integrated, which is the main question addressed in this study. A review of the literature showed divergent answers and some neglect of well-known characteristics of electricity price processes (mean reversion and spikes). By adopting a time-varying fractional cointegration analysis using both spot and one-month ahead electricity prices, this study investigated not only whether prices were converging, but also whether the pace of convergence could have been affected by special events on the supply side. The first hypothesis assessed markets reactivity to shocks:

H1: *As liberalisation evolves, the ability of EU electricity markets to overcome supply and demand shocks more quickly increases.*

The results imply that forward (one-month ahead) markets are likely to have improved their ability to overcome shocks during the period studied. Meanwhile, the behaviour of spot markets, which could be affected by local market trading arrangements and electricity mix, did not change significantly in the period analysed. Nonetheless, due to more interconnection across markets and the implementation of the EU directives, aiming to create a pan-European market, electricity prices are expected to increasingly converge. Hypotheses 2a and 2b focused on convergence and the potential differences between spot and forward markets:

H2a: *EU electricity markets are increasingly integrated.*

H2b: *Greater cointegration is observed in EU electricity forward prices when compared to prices in the respective spot markets.*

Increased convergence for all forward markets was observed and price dispersion decreased significantly, thus supporting H2a. Together with the findings on the first hypothesis, this may suggest that market integration is positively associated with resilience, i.e. increased speeds of mean reversion. Electricity spot markets which are geographically close or well-connected have been found to have longer periods of price convergence. However, overall electricity spot prices were not increasingly converging and spot price dispersion could not be linked to market integration. Therefore, hypothesis 2a was rejected for spot markets.

This study highlighted the relevance of extreme weather conditions, public holidays, reduced plant availability and fuel price developments for changes in the speed of mean reversion and convergence of electricity spot prices. For forward markets, hypothesis 2b was rejected: From the four market pairs considered, the German and Dutch electricity markets did not support the hypothesis.

The potential effects of increases in interconnection capacity were then addressed by testing:

H3a: *The speed of mean reversion after a market connecting event is faster than the mean reverting speed of the price series before the event.*

H3b: *There is no change in the speed of mean reversion of spot prices in markets which are not directly affected by the new interconnection.*

In theory, it might be expected that when connecting two markets, price resilience against shocks of the less interconnected market improved. Investigating price dynamics one year before and after the commissioning of the NorNed and BritNed interconnector this expectation was supported by our analysis. Moreover, with the exception of the Nordic-German market coupling, spot prices in markets which are directly coupled showed a faster speed of mean reversion after the initiative. Consequently, market coupling initiatives are fulfilling their objective of delivering a more robust electric system. Decisions on electricity mix and reserve margin are made at the national level since each EU member state maintains its right to "determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply" *(*Article 194, §2) (European Union, 2007). Yet, in integrated systems and markets, changes in local electricity mixes may impact on integration. In the particular case of the German market, which is the largest in the region, capacity levels decreased, therefore we tested:

H3c: *Germany´s decrease in secure capacity has lowered the ability of electricity spot prices to revert to the mean in the German and neighbouring markets.*

This hypothesis was supported by the data, thus implying that decisions on electricity mix and reserve margin in one market can affect directly and indirectly connected spot markets. Although nuclear power serves base load and thus may appear to be less related to the speed of mean reversion, the reduction led to a shift in the supply stack, decreasing secure reserve capacity in the German system (BDEW, 2011). The change in the German electricity mix and greater output from intermittent renewable sources has led to greater spot price volatility, to which the European electricity system may have reacted slower, as indicated by the increases in the order of integration of the spot price series. Consequently, as a limitation of this study future research on market integration should consider the electricity mix and other potential price drivers. Moreover, faced with emission targets and demand management, market mechanisms may change and new regulation will follow, which are likely to impact on electricity price movements and convergence. Future research should track these developments. The findings show that the Pan European Electricity market is still to become reality.

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

Long run dynamics of electricity prices in a market 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.

### 3.1. Introduction

In Europe, natural gas, coal and carbon prices have been found to be associated with electricity price movements by several researchers (Aatola et al., 2013; Asche et al., 2006; Bollino et al., 2013; Mjelde and 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 (Reinaud, 2008). 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, 2013c). 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 (GB), 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.

### *3.2. 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.

#### *3.2.1. On Electricity Market Integration*

The Law of One Price (Fetter, 1924) has been the core theoretical foundation in assessing common long run dynamics in liberalised electricity markets. Following the initial evaluations (Bower, 2002; Boisselau, 2004), several studies (e.g. Armstrong and Galli, 2005; Böckers 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.

### *3.2.2. 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 liberalised 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 Furió and Chuliá (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. Furió and Chuliá (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. Kilic and Huisman (2013) conducted a similar study for month and year ahead electricity base and peak load prices for Germany and The Netherlands between January 2008 and December 2012. The authors assessed cointergation of the two markets with coal and gas prices and found that in The Netherlands both fossil fuel futures prices play a role in the price formation for base prices. In Germany the electricity base load futures prices are cointegrated only with coal futures.

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 USA 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/ liberalisation). 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 liberalisation. 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 liberalisation 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.

#### *3.2.3. 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, 2014). 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; Sjim et al., 2006; Pinho and Madaleno, 2011a) analysed how carbon costs are linked to electricity prices. Pinho and Madaleno (2011a) 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 liberalised 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.

## *3.3. Contextual Background of European Electricity Markets*

### *3.3.1. 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, 2006).

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.

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.

Figure 3.22: Annual gross electricity generation mix from 2005 to 2012


Source: Eurostat, 2014

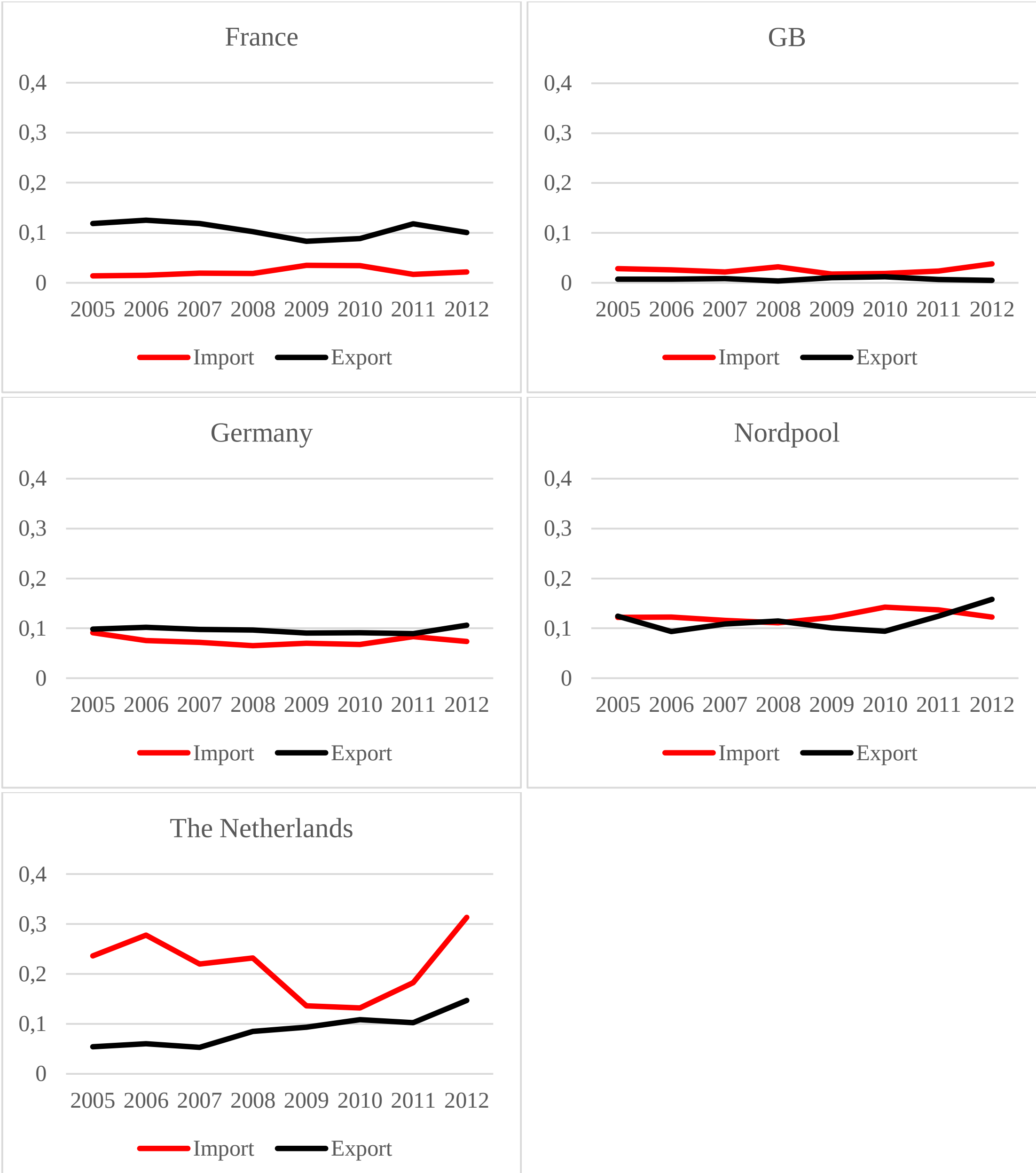
### *3.3.2. Electricity Trade in the EU*

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 TLC, 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 3.2, 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 3.23: Import and export as a ratio of total electricity generation from 2005 to 2012




Source: Eurostat, 2014

### 3.3.3. *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; Huisman and Mahieu, 2003), 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 market 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: How do fuel and carbon prices associate with electricity prices and do they affect electricity market integration?

### *3.4. Methods*

#### *3.4.1. 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 3.4.2.

Serial correlation of the electricity spot price time series are examined via estimates of the localised aurocorrelation function (LACF), as detailled in section 3.4.3. 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 3.4.4. 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.

### *3.4.2. 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 trended *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:

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

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, 1994a). 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).

### *3.4.3. 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 $\tau$ 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.

### *3.4.4. 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:

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

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

The trace ($\lambda_{trace}$) and maximum eigenvalue ($\lambda_{eigen}$) 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)).

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

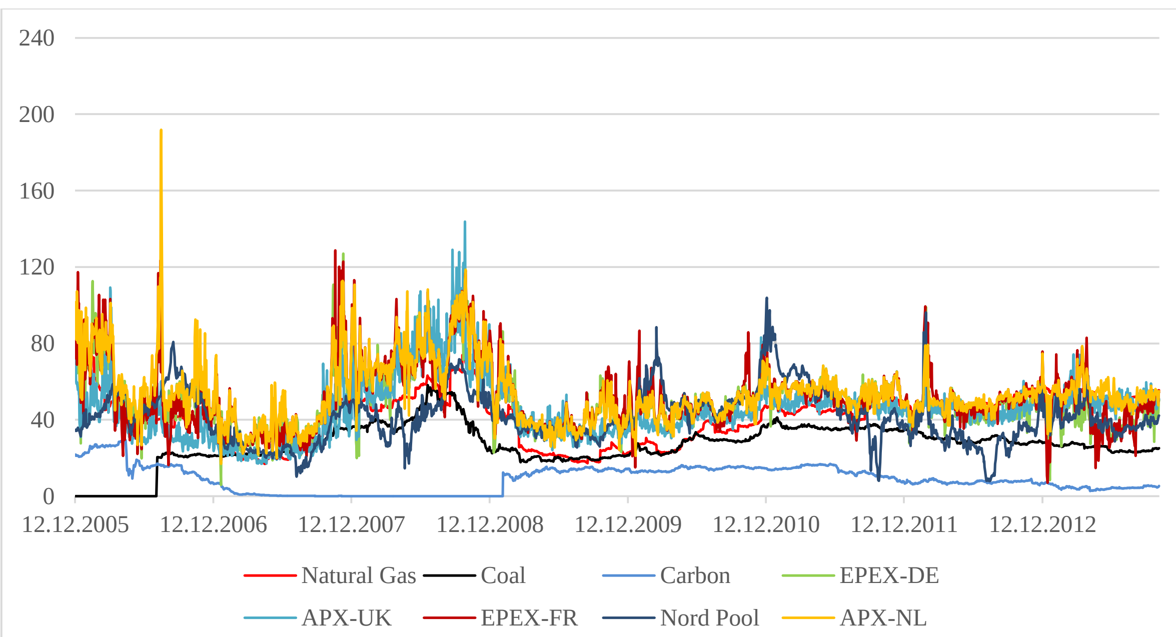
$$\lambda_{eigen}(r, r+1) = -Tln\ [1 - \tilde{\lambda}_{r+1}] \tag{6}$$

Here $T$ is the sample size and $\lambda_i$ 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).

### *3.5. Data*

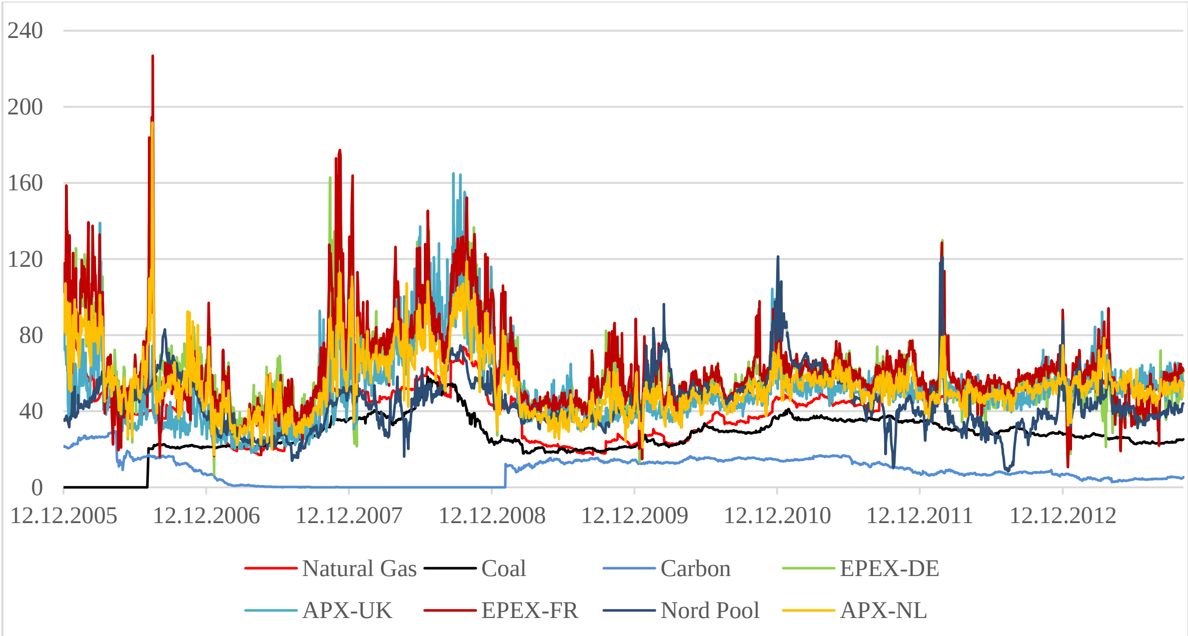
In this study we focus on the three electricity spot markets: APX-UK (GB), Nordpool (Denmark, Estonia, Finland, Latvia, Lithuania Norway and Sweden) and EPEX-FR (France). In each case, we include two other electricity markets (Germany and the Netherlands for GB; France and the Netherlands for Nordpool; Germany and GB for France) as well as API2 Coal (coal), London Natural Gas (natural gas) and EU ETS (carbon) prices. Figure 3.3 and 3.4 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 3.3: 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 3.24: 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 3.1 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 weekday 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 Denmark, Estonia, Finland, Latvia, Lithuania Norway and Sweden (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, Furió and Chuliá, 2012).

The summary statistics in Table 3.1 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.[3]

[3] 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 3.15: Summary statistics for coal, carbon, natural gas and electricity base and peak prices

| | 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 |

### 3.6. Empirical Results

#### 3.6.1. Tests for Integration and Fractional Integration

The *p-values* of the Phillips and Perron (1988) (PP) and ADF unit root test are reported in rows two to five of Table 3.2 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 estimates for the order of integration *d*_GPH in row six of Table 3.2 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 3.2 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 3.16: Assessments of long run dynamics

| | 1<br>API2 COAL | 2<br>EU ETS | 3<br>Natural gas | 4<br>FR BASE | 5<br>FR PEAK | 6<br>GER base | 7<br>GER peak | 8<br>NL base | 9<br>NP base | 10<br>NP peak | 11<br>GB BASE | 12<br>GB PEAK |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 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 |
| 2 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 |
| 3 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) |
| 5 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) |
| *6 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) |
| *7 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 |
| 8 observations | 1893 | 2048 | 2048 | 2048 | 2048 | 2048 | 2048 | 2048 | 2048 | 2048 | 2048 | 2048 |

Assessments of long run dynamics for coal, carbon, natural gas as well as electricity base and peak prices. *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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### *3.6.2. Localized Autocorrelation Functions (LACF) and Non-stationarity*

Figures 3.5 to 3.10 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 3.5 and 3.6 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 3.5 and 3.6) 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 3.7 and 3.8), though there seems to be fewer non-stationary periods compared to the Brittish market. The Nordpool LACFs in Figure 3.9 (base load prices) and Figure 3.10 (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 3.25: LACF APX-UK base

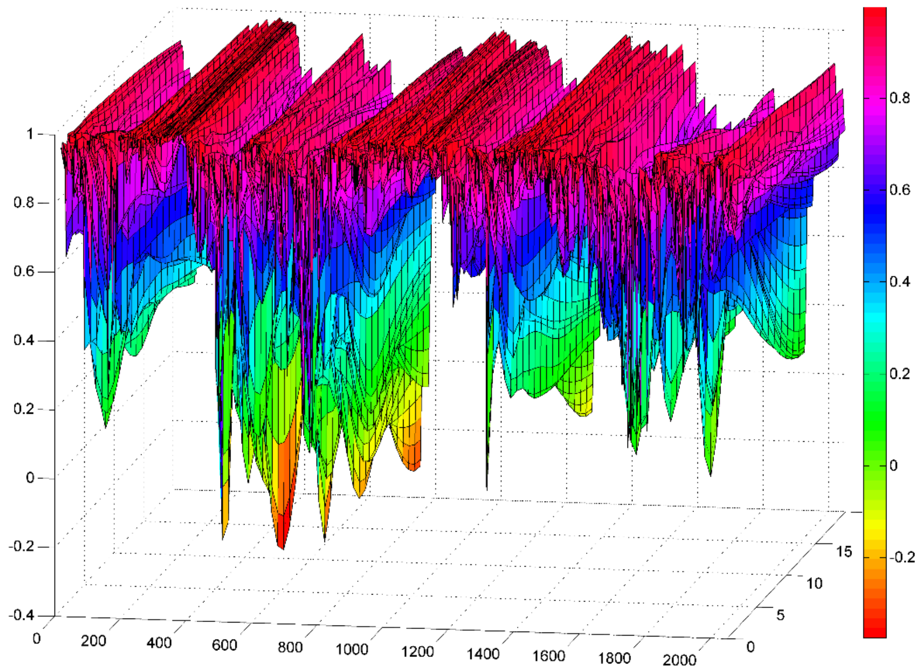



Figure 3.26: LACF APX-UK peak

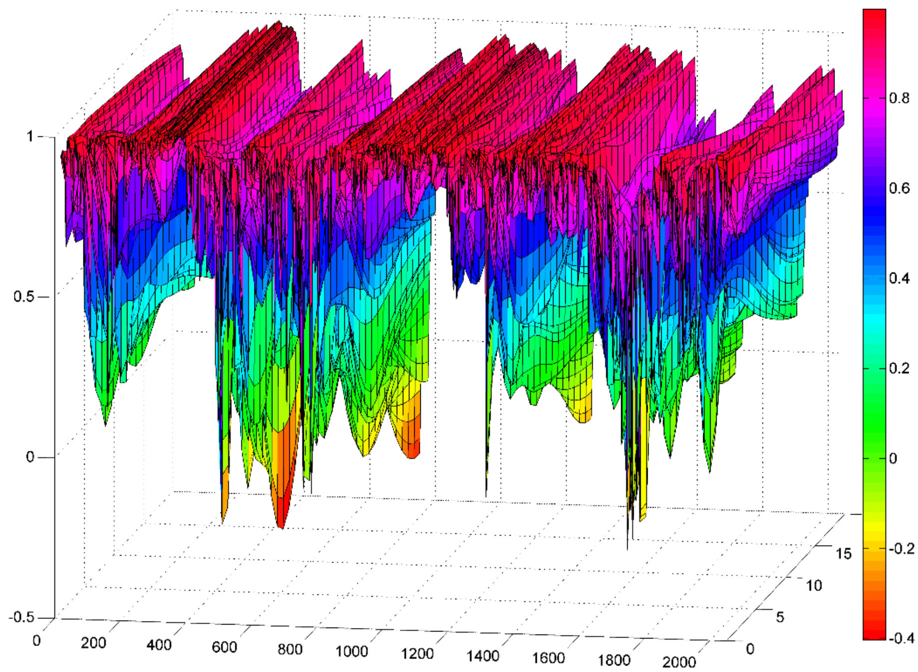


Figure 3.27: LACF EPEX-FR base

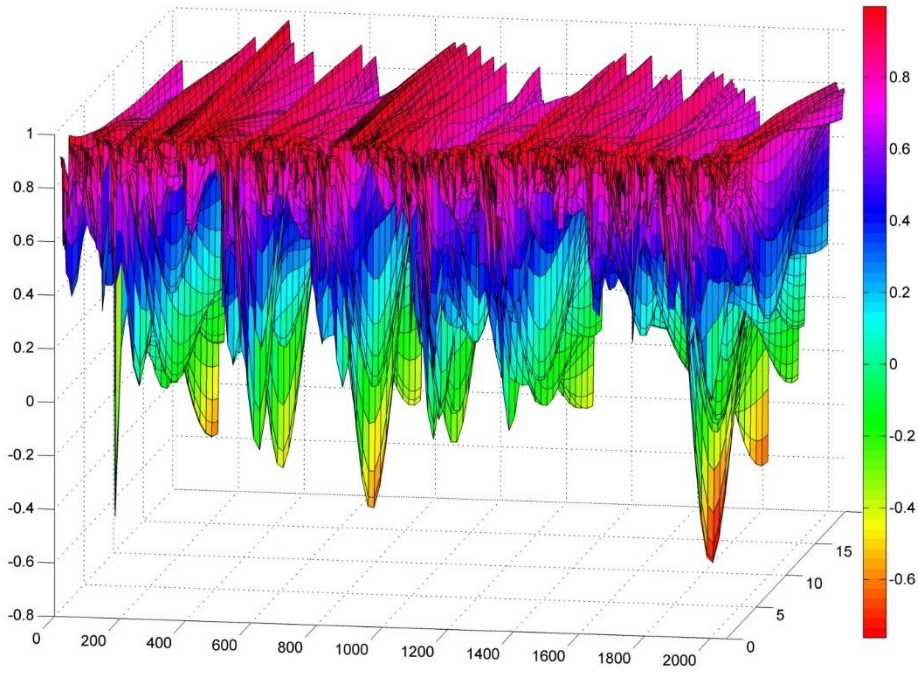



Figure 3.28: LACF EPEX-FR peak

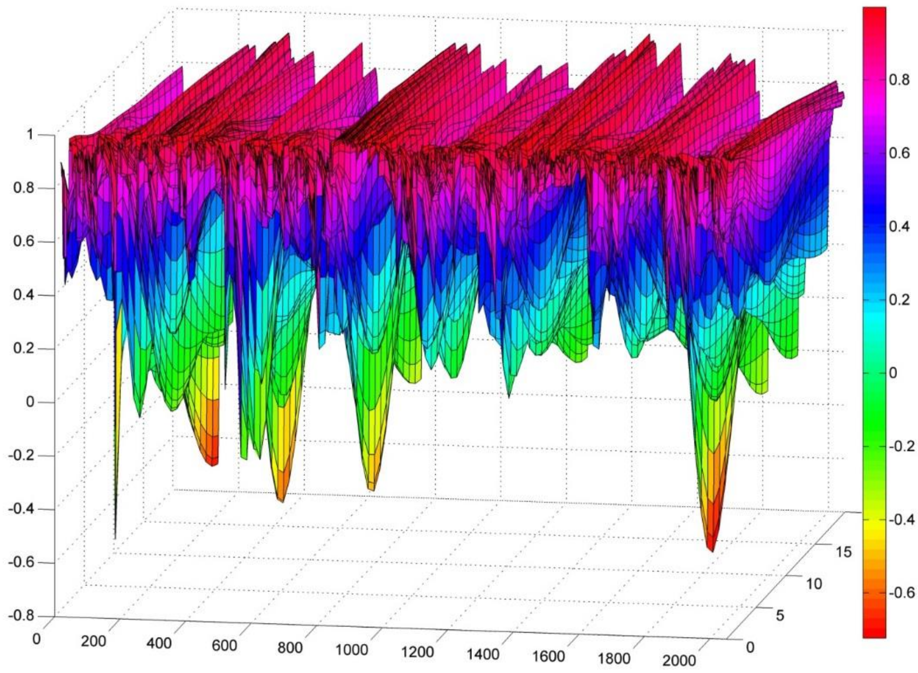


Figure 3.29: LACF Nordpool base

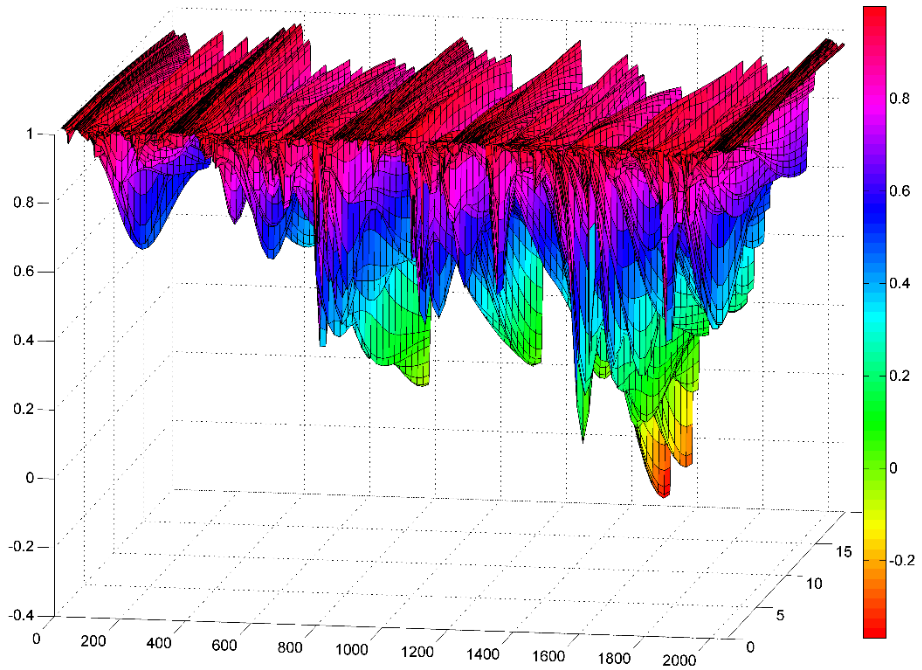
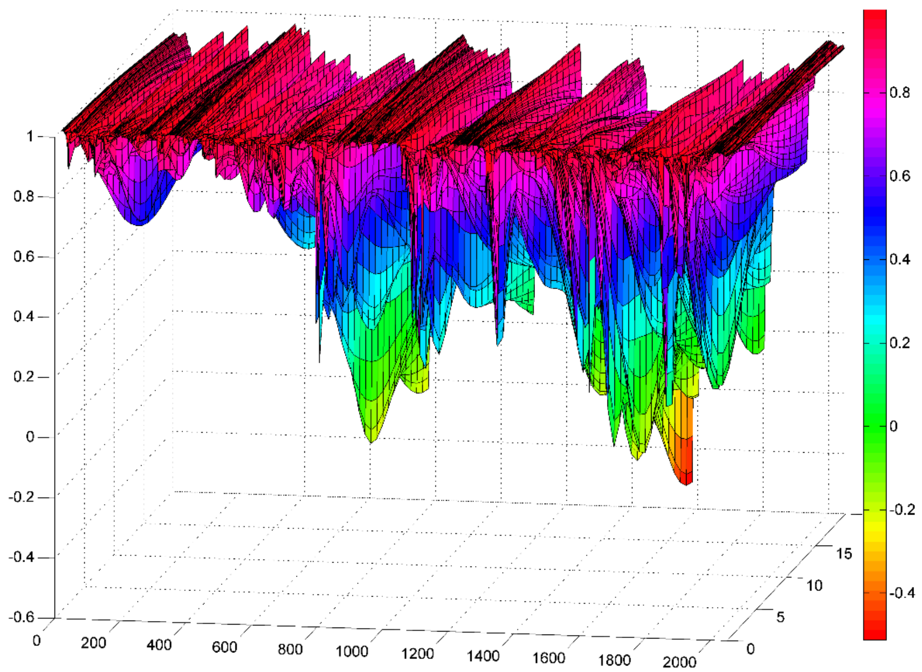


Figure 3.30: LACF Nordpool peak



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 their duration are listed in Table 3.3 in the first and second column, respectively. The unit root test results suggest that four (printewd in bold) of the ten identified 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 3.6.2.

For British electricity peak load prices nine periods could be non-stationary according to the LACF criteria. They are listed in the first column of Table 3.4. The periods are similar to British electricity base load periods but shorter. 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 3.4. Again, 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 3.17: Unit root test for British base load price periods

| | 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)* | - | - | - | | |

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 3.18: Unit root test for British peak load price periods

| | 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) | - | - | - | - |

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 3.5 and 3.7, 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 3.19: Unit root test for Nordpool base load price periods

| | 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)* | - | - | - | - | - |

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 3.20: Unit root test for Nordpool peak load price periods

| | 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)* | - | - | - | - |

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 periods lasting 68 and 70 days from February to May in 2007 and in 2009 that will be tested for a unit root were identified and reported in the first column of Table 3.7. 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 3.8 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 3.21: Unit root test for FR base load price periods

| | 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)* |

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 3.22: Unit root test for FR peak load price periods

| | 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)** |

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.

### *3.6.3. 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.

#### *3.6.3.1. GB*

The cointegration analysis for British electricity base load and peak load prices are summarised in Table 3.9 and 3.10, 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 ($\lambda_{eigen}$) and Trace ($\lambda_{trace}$) 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 3.9) and three for peak load periods (Table 3.10) 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 $\lambda_{eigen}$ 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 3.23: British Base Load Prices: Cointegration analysis

| **Period** | **Variable** | **Hypothesis** | $\lambda_{trace}$ | $\lambda_{eigen}$ |
|---|---|---|---|---|
| 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. Variables that are co-integrated with British electricity base load prices either for the Trace or Eigenvalue or both test statistics are printed in bold.

For British electricity peak load periods results are reported in Table 3.10. 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 3.24: British Peak Load Prices: Cointegration analysis

| **Period** | **Variable** | **Hypothesis** | $\lambda_{trace}$ | $\lambda_{eigen}$ |
|---|---|---|---|---|
| 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. Variables that are co-integrated with British electricity peak load prices either for the Trace or Eigenvalue or both test statistics are printed in bold.

### *3.6.3.2. Nordpool*

Table 3.11 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 3.12) 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 3.25: Nordpool Base Load Prices: Cointegration analysis

| Period | Variable | Hypothesis | $\lambda_{trace}$ | $\lambda_{eigen}$ |
|---|---|---|---|---|
| 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. Variables that are co-integrated with Nordpool electricity base load prices either for the Trace or Eigenvalue or both test statistics are printed in bold.

Table 3.26: Nordpool Peak Load Prices: Cointegration analysis

| Period | Variable | Hypothesis | $\lambda_{trace}$ | $\lambda_{eigen}$ |
|---|---|---|---|---|
| 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. Variables that are co-integrated with Nordpool electricity peak load prices either for the Trace or Eigenvalue or both test statistics are printed in bold.

#### *3.6.3.3. 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 3.13. 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 3.14 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 3.27: EPEX-FR Base Load Prices: Cointegration analysis

| **Period** | **Variable** | **Hypothesis** | $\lambda_{trace}$ | $\lambda_{eigen}$ |
|---|---|---|---|---|
| 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. Variables that are co-integrated with French electricity base load prices either for the Trace or Eigenvalue or both test statistics are printed in bold.

Table 3.28: EPEX-FR Peak Load Prices: Cointegration analysis

| **Period** | **Variable** | **Hypothesis** | $\lambda_{trace}$ | $\lambda_{eigen}$ |
|---|---|---|---|---|
| 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. Variables that are co-integrated with French electricity peak load prices either for the Trace or Eigenvalue or both test statistics are printed in bold.

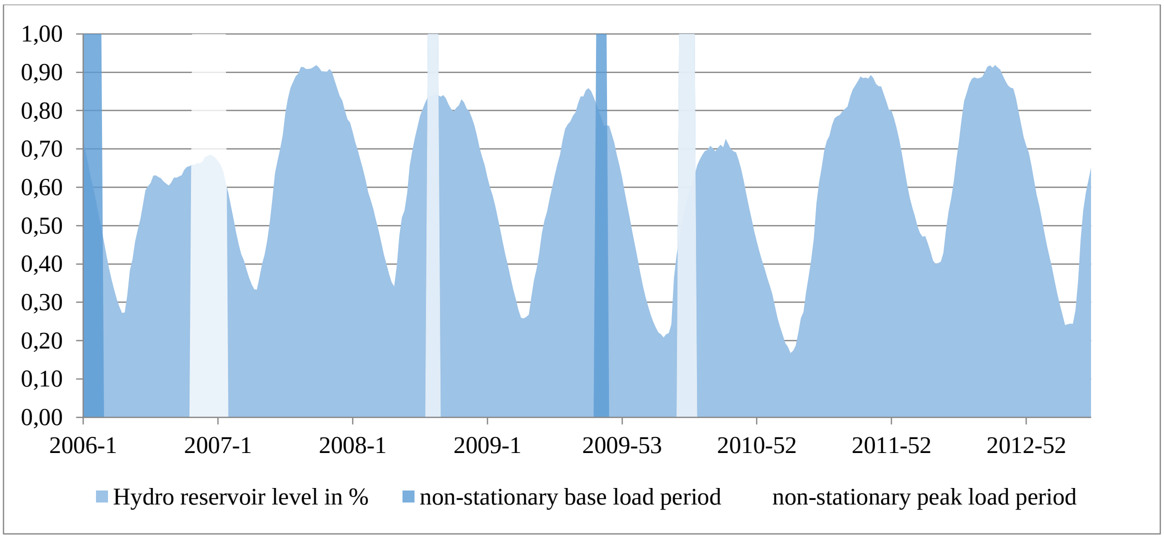
## *3.7. Discussion*

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 apparantly 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 3.11. 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 3.31: Hydro reservoir level and non-stationary periods in Nordpool

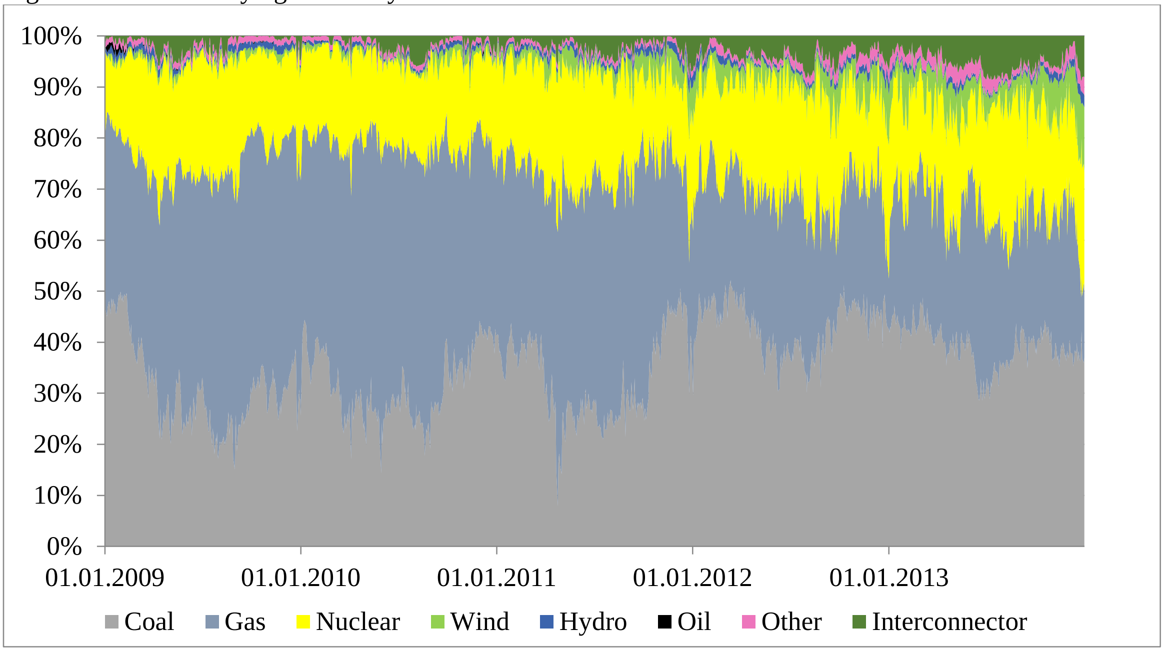



Hydro reservoir level for Nordpool and non-stationary base and peak load periods from January 2006 to June 2013 [Source: NordpoolSpot, 2014]

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.

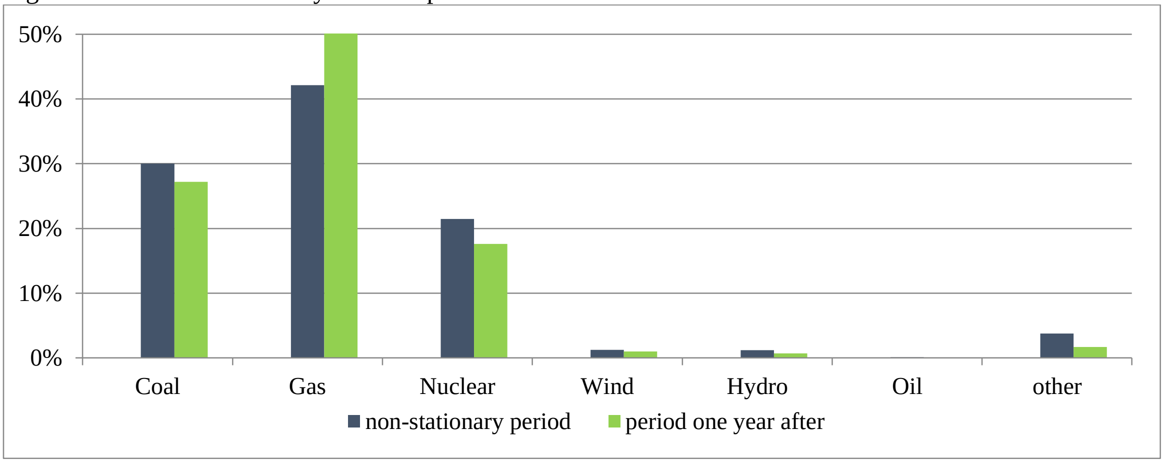
Figure 3.12 illustrates the changing electricity mix in GB between 2009 and 2013, which has also been used to create Figure 3.13 and 3.14. The two Figures display the comparison of the British electricity mix during the non-stationary period and the British electricity mix during the same period one 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, 2010d). Electricity prices were therefore soaring in the second quarter of 2010 and strongly associated with its marginal cost of production.

Figure 3.32: Time-varying electricity mix GB



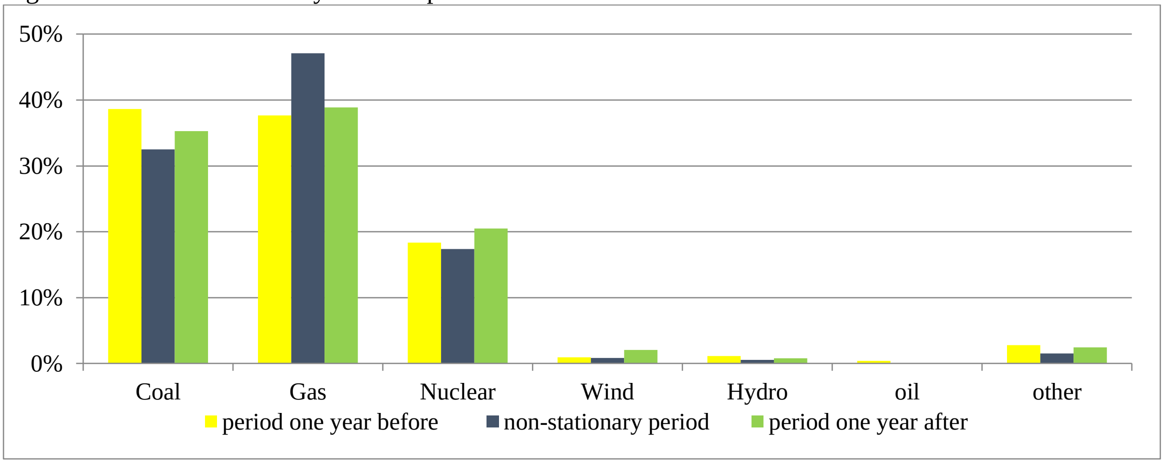

Weekday daily British electricity generation by fuel and supply by interconnector from 1.1.2009- 31.12.2013 [Source: Elexon]

Figure 3.33: British electricity 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 3.34: British electricity mix comparison B




British Fuel mix 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 3.3.1. 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 2$^{nd}$ and 3$^{rd}$ 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, 2011,b, c). 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. Liberalisation 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.

### *3.8. 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.

### *3.9. Summary*

The study set out to assess time-varying integration between electricity and fuel as well as carbon prices on the one hand and electricity market integration on the other hand in order to explore the research question:

*How do fuel and carbon prices associate with electricity prices and do they impact on electricity market integration?*

The paper argued that due to the price setting mechanism electricity spot prices might share common long run dynamics with fuel and carbon prices on the one hand and other electricity prices on the other hand. Assessments using time-varying localized autocorrelation function and cointegration analysis revealed that interconnection with other markets and the local electricity mix played crucial roles for common long run dynamics with fuel prices. Table 3.14 summarizes the periods during which the markets under study and the variables were found to be integrated.

Table 3.294: Summary of periods of convergence

| Market | Variable | Period during which market and variable converged |
|---|---|---|
| **British Base Load Prices** | **EU ETS** | 26.09.2006-08.11.2006 |
| | **EU ETS** | 28.11.2006-31.05.2007 |
| | **Natural gas** | 21.12.2009-14.5.2010 |
| | **API2 Coal** | 21.12.2009-14.5.2010 |
| **British Base Load Prices** | **EU ETS** | 29.09.2006-07.11.2006 |
| | **EU ETS** | 29.11.2006-31.05.2007 |
| | **API2 Coal** | 19.01.2010-14.05.2010 |
| | **EU ETS** | 19.01.2010-14.05.2010 |
| **Nordpool Base Load Prices** | **Ger Base** | 31.07.2008-02.09.2008 |
| **Nordpool Peak Load Prices** | **Ger Peak** | 31.07.2008-29.08.2008 |
| **EPEX-FR Base Load Prices** | **Natural Gas** | 07.02.2007-11.05.2007 |
| **EPEX-FR Peak Load Prices** | **GB Peak** | 17.06.2011-09.08.2011 |
| | **GER Peak** | |

The GB market which was the least connected of the three markets that were studied, exhibited low electricity import and export figures. The share of natural gas as well as coal in the GB electricity mix was significant throughout the analysis period. Accordingly, it was found that neither GB electricity peak nor base load prices shared common long run dynamics with any of GB´s interconnected markets that were studied. However, periods of convergence could be found with natural gas, coal and carbon prices. Nordpool and France on the other hand, are well connected to other electricity markets, with substantial cross-border trade. Accordingly common long run dynamics were identified for both markets with Germany. Convergence with fuel prices was only found for French base load prices and natural gas in the first months of 2007.

The main policy implication that can be derived from these findings is that electricity market integration seem to counter-balance common long run dynamics between electricity spot prices and fuel or carbon prices. This is an important finding especially if a country uses a generation technology which mainly relies on foreign energy imports. Germany for example has a large share of natural gas in its electricity mix much of which is imported from Russia. The historical assessment of the study suggest that natural gas price increases are unlikely to result in electricity spot price increases as the price series were not found to be cointergated. This finding is consistent with the reasoning that a well-connected European market for electricity reduces its dependency on a specific generation technology by drawing on a larger pool of source and therefore improves security of energy supply, even if the share of the fuel in the domestic electricity mix is substantial.

From a GB perspective the advantage of reducing the dependency on countries it imports fuel from via increasing interconnectivity is therefore of lesser importance as most of the energy sources are produced domestically. However, the GB electricity market is still exposed to international fuel price developments. This means that price developments of natural gas, carbon and coal are more likely to be reflected in GB electricity prices.

Another interesting finding is that neither Nordpool nor France showed periods of convergence with carbon prices. The GB on the other hand showed periods of common long run dynamics with EU ETS prices. This might be taken as another indicator of the limited possibility of the GB to adjust its electricity production to price developments.

## 4. Germany's Nuclear Power Plant Closures of 2011 and the Integration of Electricity Markets in Europe

In 2011, eight nuclear power plants were closed within a period of a few months, thus increasing the share of intermittent wind power in Germany. Since a pan-European electricity market is envisaged, this paper examines the potential implications for interconnected European electricity markets. The short- and long-run interrelationships of daily electricity spot prices, from November 2009 to October 2012, in APX-ENDEX (GB and The Netherlands), Belpex (Belgium), EPEX-DE (Germany), EPEX-FR (France), Nordpool (Norway, Denmark, Sweden, Finland, Estonia and Lithuania), OMEL (Portugal and Spain) and Swissix (Switzerland); and wind power in the German system are modelled. Two MGARCH models with dynamic correlations are employed, and a fractional cointegration analysis is conducted to investigate any change in the long-run behaviour of electricity spot prices. Results indicate that in interconnected electricity markets local policies may have wider implications, as there are: positive time-varying correlations between spot market volatilities in markets with substantial shared interconnector capacity; a negative association between wind power volatility and electricity spot price fluctuations; and, for most markets, a decreasing price resilience to market shocks.

### *4.1. Introduction*

Germany, Europe's largest economy and biggest $CO_2$ emitter, is committed to reduce its emissions between 80 to 95% below the level of 1990 by the year 2050. In spite of a 37 % growth in GDP, so far 21% has since been achieved (Committee on Climate Change, 2013). Given Germany's targets, the electricity sector has been under significant pressure to reduce emissions, increase efficiency, and minimise costs. Since the introduction of the Renewable Energy Source Act (RESA, 1991), electricity generation from intermittent renewable energy sources (RES-E) in Germany has grown considerably. Wind power capacity has increased from 183MW in 1992 to 31,308MW in 2012, which corresponds to approximately one third of the installed EU wind power capacity in 2012 (EWEA, 2012).

In 2010 a long-term energy strategy was proposed to transform Germany into one of the most energy-efficient and environmentally-friendly economies (Bundesregierung, 2011). This strategy became known as *Energiekonzept* and, following the events at Fukushima in 2011, it was reinforced by the 13$^{th}$ *Gesetz zur Änderung des Atomgesetz* (Nuclear Phase-Out Act), which led to the closure of eight nuclear power plants within a period of a few months in 2011. Subsequently, the Renewable Energy Source Act 2012 (RESA, 2012) reaffirmed the feed-in tariff policy that prioritises RES-E and pledges to connect all renewable producers to the grid. Pursuing a nuclear phase-out together with ambitious renewable energy targets is so far unique for a major industrial country with limited indigenous natural gas reserves and a low hydro share in its electricity mix. The German energy transition (*Energiewende*) has been criticised on the grounds that Germany may need to import electricity from foreign nuclear power plants to compensate for the loss in its generation capacities (Öko Institut, 2013). In fact, recently, a combination of declining EU ETS carbon and coal prices has favoured coal-fired electricity generation (European Commission, 2013b). The German electricity market is the largest in central Europe and there may be unintended consequences of its energy policy, especially in interconnected electricity markets, as illustrated by Germany's Environment Minister's admission that a unilateral course had been taken in 2011: '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).

A consensus on European energy policy could promote cleaner electricity mixes, make maximum use of complementarities and lead to dynamic pricing as well as aligned grid investment strategies (Böckers et al., 2013). Diverse resource endowments and generating technologies across integrated systems offer greater resilience to market shocks. If all markets focused solely on local needs, their combined electricity systems could amount to an overinvestment in capacity and unnecessary costs to consumers and tax payers, because a centrally co-ordinated dispatch requires an aggregated lower reserve margin (Hooper and Medvedev, 2009). An example of mutual gains is the flow of the NorNed interconnector, which changes direction depending on precipitation levels. According to the European Network of Transmission System Operators for Electricity’s (ENTSO-E) electricity exchange statistics, The Netherlands was a net importer from Norway in 2008 (2.8TWh) and 2009 (1.6TWh). Yet, in 2010, a very dry year in Scandinavia, The Netherlands was a net exporter to Norway (1.0TWh). This exchange resulted in lower average prices with fewer fluctuations in both electricity markets (Teusch, 2012).

The present study aims to contribute to the policy debates on the integration of European electricity markets and implications of Germany’s nuclear phase out, by empirically investigating the interrelationships of European electricity spot prices and wind power penetration in the German day-ahead market. In the next section, the literature on the implications of renewables for electricity price behaviour and market integration is reviewed. The third section sets the contextual background and the hypotheses to be tested. Sections four and five describe the methodology and the data, respectively. The results are then reported in section six. Section seven concludes the paper.

### *4.2. Renewables in Liberalised Electricity Markets*

Several studies have addressed renewable electricity generation and possible implications for electricity price dynamics and market integration. The relevant literature can be divided into three subsections: (1) analysis of the potential effects of RES-E integration on liberalised electricity markets, (2) studies of electricity price volatility and (3) investigations of long-run dynamics and convergence in electricity markets. Each subset is reviewed below and its implications for the present study are highlighted.

### *4.2.1. The Integration of Renewables in Liberalised Electricity Markets*

A body of literature (e.g. Gross et al., 2006; Henriot and Glachant, 2013; Holttinen et al., 2009; Smith et al., 2007) has focused on the challenges associated with growing RES-E integration, including the need for conventional back up capacity to mitigate the risks of shortages and blackouts. 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) showed that increasing wind power penetration in countries like Denmark, Spain or Germany appears to be negatively correlated with electricity spot prices. A reduction in wholesale prices with increasing wind penetration is attributed to the merit order of dispatch, where cheaper wind-generated electricity supersedes offers from generators whose technologies have higher marginal costs (Cludius et al., 2014; Forrest and MacGill, 2013; Sensfuß et al., 2008; Woo et al., 2011, Würzburg et al., 2013). However, prices for the final consumer are likely to increase, as they may include RES-E support schemes (Paraschiv et al., 2014). A side-effect of integrating intermittent RES-E to electricity markets is an increase in spot price volatility and price risks due to the combination of the limited storability of electricity, which implies instantaneous balance of supply and demand, and the high variability of wind power (Paraschiv et al., 2014). Consistent with this expectation, when Green and Vasilakos (2010) examined the impact of wind generation on British hourly balancing prices and output, they found that the volatility of prices and base load generators’ profits increased significantly. By contrast, 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. They concluded that competitive markets are unlikely to cope with the planned increases in wind power and called for additional policies to facilitate the integration of RES-E generation. In addition, Schaber et al.´s (2012) investigation of regional grid extension scenarios highlighted that, without grid extensions, revenue losses would occur in the proximity of large RES-E generators.

More recently, Spiecker et al. (2013) evaluated investments in transmission lines in the northern European electricity system and found increases in flexible gas fired mid-merit and peaking units, but also a reduction in base load capacity. They argued that the need for more flexible generation capacity can be reduced by grid extensions. Consequently, inferences have been made that interconnection and market coupling can favour the integration of RES-E to the electric system. In this context, Oggioni et al. (2014) and Neuhoff et al. (2013) investigated different wind integration policies, by using simulation models of policies for dispatch and transmission capacity. In all, their findings suggest that, with high wind power penetration, priority dispatch is in detriment of market integration. Although nodal pricing could make better use of existing transmission capacities, it may not be sustainable under priority dispatch.

In summary, high wind power penetration levels can affect local networks adversely. Although market coupling and interconnection are likely to be useful for the integration of intermittent RES-E to the European electricity system, the RES-E priority dispatch rule in Germany may also affect the operation and investment of power plants in neighbouring markets. Consequently, spot price volatility that has been found to be associated with RES-E penetration in local markets should be considered when investigating integrated electricity systems.

### *4.2.2. Spot Price Volatility Dynamics in Liberalised Electricity Markets*

Jonsson et al. (2010) and Woo et al. (2011) reported significant associations between wind power penetration levels and electricity spot price volatility in Denmark and Texas, respectively. In the specific case of the German market, Ketterer (2014) assessed the effect of wind power generation on the mean and volatility of the electricity spot prices between 2006 and 2012 and concluded that in general wind generation increased spot price volatility. Nonetheless, a decrease in spot price volatility was also observed after a regulatory change in the German market, which required the TSOs (Transmission System Operator) to forecast the renewable production one day ahead.

To date, multi-market empirical studies appear to have neglected the possible effects of RES-E generated electricity in interconnected regions. For example, Worthington et al. (2005) employed a MGARCH model to estimate price volatility within five Australian electricity spot markets. Their results showed positive lagged mean spillover in two markets and no mean spillover across markets, but there were significant own and cross volatility spillovers in nearly all of the markets. Bunn and Gianfreda (2010) used impulse response functions to analyse volatility interactions between five European spot and forward markets (British, Dutch, French, German, Spanish) between 2001 and 2005. They found volatility transmission to decrease with the proximity to the maturity of the contracts. Zareipour et al. (2007) compared different volatility indices in four interconnected North American electricity markets (Ontario, New England, New York, and PJM) and observed that volatility increased in the direction of well-connected, less mature or smaller markets. While examining spot prices in four Australian electricity markets from 1999 to 2007, Higgs (2009) observed that the less direct the interconnection between markets, the lower the volatility spillover between them.

While examining connected European markets, Solibakke (2008) used a BEKK (Engle and Kroner, 1995) model to investigate volatility correlations between the daily German electricity price index Phelix and spot prices from Nordpool between 2000 and 2006, and found strong cross-market correlations that could last for up to three days. Similarly, Le Pen and Sévi (2010) investigated daily forward prices from March 2001 to June 2005 and found evidence of return and volatility spillover effects in the German, Dutch and British electricity forward markets using volatility impulse response functions.

In summary, the literature shows that associations of electricity price volatilities, of interconnected markets can be significant, thus adding uncertainty from the perspective of an integrated market. It is therefore plausible that, within EU electricity markets, a local policy which impacts on a regional electricity mix could alter the short and long-run dynamics of other markets and ultimately affect the process of convergence to a single market. We therefore review the accumulated evidence on the convergence of liberalised European electricity markets.

#### *4.2.3. Price Convergence in Liberalised Electricity Markets*

Since the initial evaluations of electricity market integration (Bower, 2002; Boisselau, 2004), the Law of One Price (Fetter, 1924) has been adopted as the core theoretical foundation to examine common long-run dynamics. Lundgren et al. (2008) assessed how integration affected electricity price dynamics in the Nordic electricity market between 1996 and 2006. Investigating mean electricity prices, conditional variance and jump-intensity, they found that an integrated market can handle external shocks to supply and demand more efficiently. Hence, possible synergies between intermittent RES-E and electricity market integration should exist (Teusch, 2012). However, subsequent studies of common long-run dynamics in electricity markets have widely ignored the potential consequences of RES-E policies. Armstrong and Galli (2005) examined four electricity bourses in Europe (France, Germany, The Netherlands and Spain) from January 2002 to December 2004 and found that the average price difference between markets decreased in almost all cases, and more rapidly in peak periods compared to off-peak periods. Kalantzis and Milonas (2010) appear to support Armstrong and Galli's (2005) conclusion, since they also found spot price convergence to be higher during peak hours across eight markets in Central and Western Europe (APX-UK, APX-NL, Belpex, EPEX-DE, EPEX-FR, EXAA, Nordpool and OMEL) between 2006 and 2009. Using retail data from 1978 to 2003 for ten European countries (Denmark, Finland, France, GB, Germany, Greece, Ireland, Italy, Portugal and Spain), Robinson (2008) also concluded that electricity prices converged. Bunn and Gianfreda's (2010) analyses showed increasing market integration between France, GB, Germany, Spain and The Netherlands between 2001 and 2005 for both electricity spot and forward markets. By contrast, Zachmann (2008) inferred that by mid-2006, the integration of eleven European regional markets (Austria, Czech Republic, East Denmark, France, GB, Germany, Poland, Sweden, Spain The Netherlands and West Denmark) had not been achieved. Similarly, Pinho and Madaleno (2011b), whose wavelet analysis considered six markets (Austria, France, Germany, Nordpool, Spain and The Netherlands) between 2000 and 2009, concluded that electricity market integration in Europe was still in its infancy. In fact, a more recent assessment (Pellini, 2012) of fifteen European markets, which included data until January 2012, arrived at a similar conclusion. Nonetheless, Bollino et al. (2013) while assessing the dynamics of four markets (Austria, France, Germany and Italy) between 2004 and 2010, observed that the German electricity prices acted as a signal for neighbouring markets. Their work therefore suggests that developments in the German electricity market can potentially impact the development of the pan

European electricity market. More recently Castagneto-Gissey et al. (2014) highlighted the impact of market coupling in electricity market integration. Adding to the literature Bask and Widerberg (2008) assessed market integration of the Nordpool area between January 1993 and December 2005 and found a positive association between market integration and stability of electricity prices.

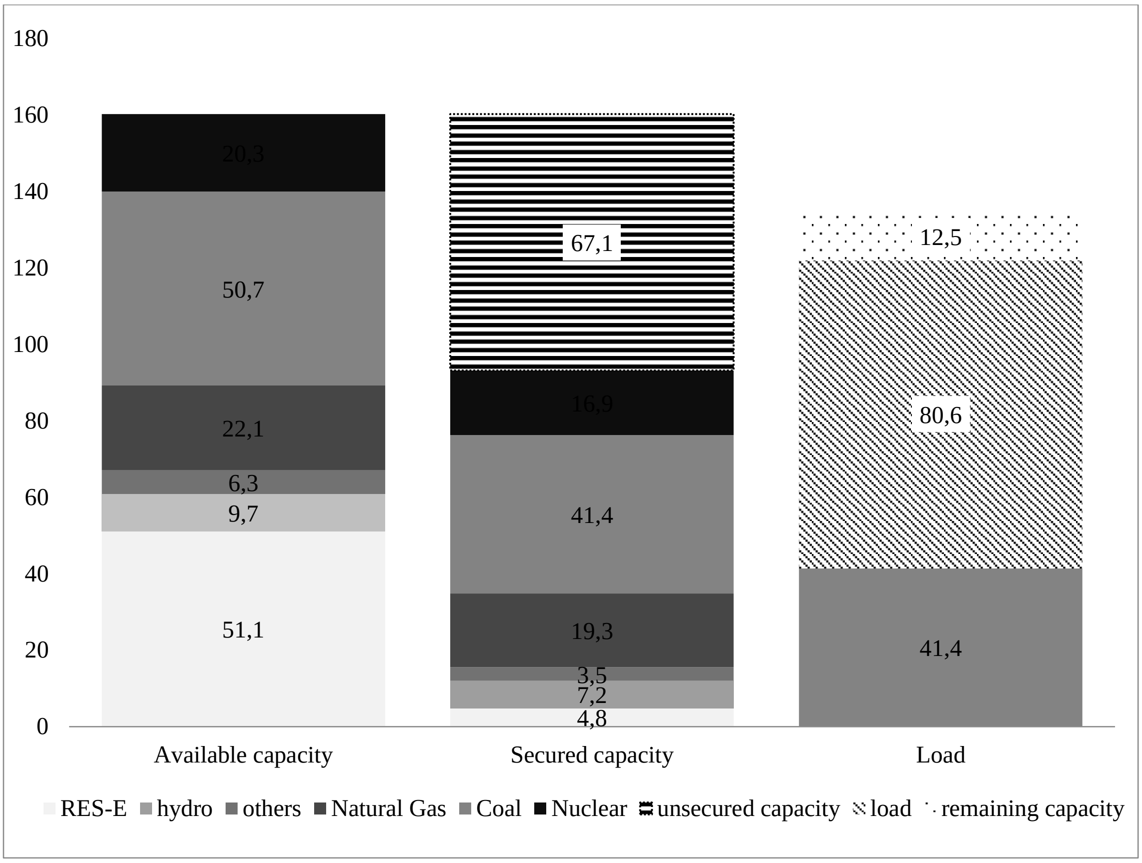
It could be argued that in the liberalised EU markets, common price dynamics would reflect the marginal cost generation in the region. Several studies have therefore assessed common long-run dynamics between conventional energy sources and electricity prices (e.g. Asche et al., 2006; Bollino et al., 2013; Bosco et al., 2010; Kalantzis and Milonas, 2010; Mjelde and Besseler, 2009; Mohammadi, 2009; Sensfuβ et al., 2008). In this line of research, Aatola et al. (2013) were the first to address RES-E integration 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 appear to have a positive but uneven effect on integration. More recently, Brunner (2014) highlighted that the association between electricity demand and spot prices in Germany is likely to be moderated by the supply of RES-E.

To date, the three streams of literature have little in common. Studies on the integration of RES-E on price dynamics, outlined in (2.1.) have focussed on a specific market. Studies that assessed short run interrelationships (2.2) or price convergence in the long-run (2.3) neglected the potential effects of RES-E penetration. The present study attempts to link these streams of literature, by focussing on how wind power penetration in the German market may have impacted spot price behaviour in Germany and connected markets. The next section sets the contextual background.

### *4.3. Germany's Nuclear Plant Closures and EU Electricity Markets*

The decommissioning of eight nuclear power plants in Germany as a response to the events in Fukushima led to a significant reduction in gross electricity generation capacity from nuclear, which decreased by 23% from 140.6TWh in 2010 to 108.8TWh in 2011 (Öko Institut, 2013). This reduction increased the overall share of intermittent RES-E in the German electric system thus altering secure capacity, which is the part of the capacity that is available 99% of the time. Figure 4.1 illustrates both the secured and available electricity generation capacities in Germany in January 2011 in GW.

Figure 4.35: Available and secure electricity generation capacity and peak load in Germany in January 2011




Source: BDEW, 2011.

At that point in time, RES-E generation made a very limited contribution to the secure capacity of the German electrical system. Of the total installed RES-E capacity (51.5GW), shown in Figure 4.1, only 9% (4.8GW) was classified as secure and thus was available during 99.9% of the time. 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 7.3GW which was recommended by ENTSO-E. However, after the closures of eight nuclear plants in 2011, the reserve margin decreased to 6.2GW, which means that reserve fell below the security threshold (BDEW, 2011).

Until August 2011, Germany had traditionally been a net exporter of electricity with stable commercial flows. Exports were generally to the Benelux countries, which have a high proportion of variable electricity sources, such as coal- and gas-fired plants. Germany imported electricity from France, which is 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) electricity generation (European Commission, 2012a). Electricity flows with Denmark, Sweden and Poland depended on the availability of wind power (BDEW, 2011). With lower reserve margins, trade patterns might have been altered. In fact, 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 in mid-March coincided with the seasonal shift in Germany's electricity trade with neighbouring markets: electricity is 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). In fact, when assessing a longer period (one year before and one year after 6th of August 2011), Germany maintained its position as a net exporter. Overall imports rose to 894GWh, while net exports reached 5103GWh. The trade statistics show that cross-country commercial flows increased (ENTSO-E, 2014) and that the expectation of greater imports was not confirmed. Similarly, the volume of electricity exported did not decrease. The reduced 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, an increase of over 30% can be observed (BWE, 2014). Furthermore, electricity generated from photovoltaic, increased from 11.73TWh in 2010 to 30TWh in 2013 (AGEB, 2014). In short, favorable weather conditions and strong investments in wind and solar farms further increased the share of electricity generated by intermittent RES-E in the German electricity mix since 2011.

### *4.3.1. Implications for EU Electricity Markets*

The drop in base load capacity and the increasing share of RES-E in the German system 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 implying greater movements in spot prices. Furthermore, in periods of low wind, there would be a shift towards the steeper slope in the merit order curve and therefore, small changes in demand or supply could lead to stronger price fluctuations. Given the central geographic position of the German electricity market in the EU and its interconnection with neighbouring markets, changes in local price dynamics may become regional. In other words, we put forward:

H1a: *After Germany's nuclear power station closures in 2011, correlations of spot prices across EU electricity markets increased.*

As reported in the preceding section, a higher proportion of wind-generated electricity can be linked to increases in price volatility within one market. However, in European 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 market players recognise profitable arbitrage opportunities. By buying electricity in a cheaper market and selling it in a higher cost market, price and wind fluctuations correlate between neighbouring markets. Following the changes in the electricity mix and the German merit order curve, which were described above, the associations between wind power penetration and spot price levels in the German and in neighbouring electricity markets, are likely to have increased, i.e.:

H1b: *Following Germany's nuclear power station closures in 2011, stronger associations between wind power penetration and spot price volatilities are observed.*

#### *4.3.2. Implication 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 become quicker as an integrated EU electricity system relies on a larger generation portfolio. Yet, unilateral energy policies, such as Germany's nuclear plant closures, could impact on the speed with which electricity prices revert to their mean. Persistence of price spikes (decrease in the speed of mean reversion) would signal reductions in system flexibility, as unexpected changes in demand or supply levels are less easily overcome. System flexibility is thus a function of reserve margins, interconnection and generation technologies. We hypothesise:

H2a: *After Germany's nuclear power station closures in 2011, the speed with which electricity spot prices revert to the mean has decreased.*

#### *4.3.3. Cointegration of EU Electricity Markets*

Changes in the long-run dynamic of spot prices may also affect their convergence to a marginal cost of generation. For example, a volatile merit order curve in Germany could lead to increased price differentials between the German and interconnected markets, if interconnection capacity is insufficient or if markets are unable to quickly respond to price signals. Hence:

H2b: After *Germany's nuclear power station closures, less integration between EU electricity spot markets is observed.*

## *4.4. Methodology*

### *4.4.1. Assessing Volatility: Dynamic Conditional Correlation Models*

To assess hypotheses 1a and 1b we follow Tse and Tsui (2002), who proposed a dynamic conditional correlation model, which hereafter is referred to as TTDCC. The estimation of the conditional correlations takes place in two steps. First, the univariate ARMA GARCH models are estimated for each time series in order to remove the predictable component and to produce the innovations $e_t$. The conditional variance of a univariate GARCH (1, 1) process and the random error term $\varepsilon_t$ is specified as:

$$\varepsilon_{it} = h_{it} e_{it} \tag{1}$$

With

$$h_{it} = \beta_0 + \beta_1 \varepsilon_{it-1}^2 + \beta_2 h_{it-1} \tag{2}$$

Where $h_{it}$ is the conditional variance of volatility of $\varepsilon_{it}$ at time t, $\beta_0$ is a constant, $\beta_1$ and $\beta_2$ are the ARCH and GARCH coefficients.

Thereafter the dynamic conditional covariance matrix $H_t$ at time *t* is estimated using the conditional variances obtained from the univariate models. The TTDCC conditional covariance matrix is specified as follows:

$$H_t = D_t \Gamma_t D_t = \rho_{ijt}(h_{iit}\ h_{jjt})^{\frac{1}{2}}, \tag{3}$$

With

$$D_t = diag(h_{11t}^{\frac{1}{2}} \dots h_{KKt}^{\frac{1}{2}}) \tag{4}$$

And the conditional variance of the univariate GARCH model for variable *i* as

$$h_{iit} = \beta_0 + \beta_1 \varepsilon_{it-1}^2 + \beta_2 h_{iit-1} \tag{5}$$

where $1 \leq i \leq j \leq K, t = 1, \dots, N; K$ is the number of variables in the model and *N* is the number of observations in the estimation period; $\Gamma_t$, the *K*x*K* symmetric positive definite time-varying conditional correlation matrix with diagonal elements that are $\rho_{ii} = 1, \forall i$ andis defined as:

$$\Gamma_t = (1 - \theta_1 - \theta_2)\Psi + \theta_2 \Psi_{t-1} + \theta_1 \Gamma_{t-1}, \tag{6}$$

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

$$\Psi_{t-1,j,i} = \frac{\sum_{m=1}^{M} \xi_{i,t-m} \xi_{j,t-m}}{\sqrt{(\sum_{m=1}^{M} \xi_{i,t-m}^2)(\sum_{m=1}^{M} \xi_{j,t-m}^2)}} \qquad 1 \leq i \leq j \leq K \tag{7}$$

and

$$\xi_{it} = e_{it}/h_{iit}^{\frac{1}{2}} \tag{8}$$

In addition, we estimate Engle's (2002) alternative proposal for the dynamic conditional correlation matrix, i.e.:

$$\Gamma_t = diag\left(q_{11t}^{-\frac{1}{2}} \dots q_{KKt}^{-\frac{1}{2}}\right)\left((1 - \theta_1 - \theta_2)\bar{Q} + \theta_1 \xi_{t-1} \xi_{t-1}' + \theta_2 Q_{t-1}\right) diag\left(q_{11t}^{-\frac{1}{2}} \dots q_{KKt}^{-\frac{1}{2}}\right) \tag{9}$$

$\bar{Q}$ is the $K$x$K$ unconditional correlation matrix of $\xi_t$, and $\theta_1$ and $\theta_2$ are non-negative parameters satisfying $\theta_1 + \theta_2 < 1$ (Higgs, 2009). Hereafter, we refer to this formulation as the EDCC model.

*4.4.2. Assessing Price Dynamics: Fractional Integration*

Long-run associations of electricity spot prices can be obscured because of the presence of large spikes. Consequently, the time series needs to be smoothed before any estimation of long-run dynamics. We refer to Trück et al. (2007) for the outlier treatment that is adopted here. In the present study outliers are defined as values that exceed or fall behind the rolling window mean average by three standard deviations over a one-month period. They were replaced by a mean average of lags and leads within one month. Four iterations were conducted until no outliers were detected.

In order to assess changes in mean reversion (hypothesis 2a), we rely on the concept of fractional integration: 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:

$$(1-L)^d = \sum_{k=0}^{\infty} \frac{\Gamma(k-d)L^k}{\Gamma(-d)\Gamma(k+1)}, \tag{10}$$

For $-\frac{1}{2}<d<\frac{1}{2}$, the process is stationary and invertible as $d>\frac{1}{2}$ is non-stationary, but mean reverting for $\frac{1}{2} \leq d<1$ (Robinson, 1994a).

Key to this concept is the value of the order of integration parameter *d*, for which a semiparametric two-step feasible exact local whittle (FELW) estimator, which was proposed by Shimotsu (2006), will be used. This estimator is robust to misspecification of the short-run dynamics and can handle both stationary ($d<$ ½) and non-stationary ($d\geq$ ½) processes (Okimoto and Shimotsu, 2010). Based on previous discussions (e.g. Robinson and Henry, 1999; Shao and Wu, 2007), this estimator is unlikely to be affected by conditional heteroscedasticity, which is a characteristic of electricity price series. We set the bandwidth *m* for the FELW to 0.75, as proposed by Lopes and Mendes (2006).

First, we plot the time varying change of the order of integration by using a rolling window of 200 observations for a graphical analysis. The estimates are smoothed with a Hodrick-Prescott (1997) filter and a smoothing parameter lambda= 250. One hundred perturbed series were obtained by adding a random noise (*N(0,1)*) to the original time series. Their order of integration, *d,* is then estimated by using the FEWL based on *n*=260 observations, corresponding to a period of one year, both before (*d*_before) and after (*d*_after) the closure of the eighth nuclear plant.

### *4.4.3. Assessing Market Integration: a Fractional Cointegration Analysis*

To test for electricity spot price convergence (hypothesis 2b), we adopt the *fractional cointegration* framework (Granger, 1986; Engle and Granger, 1986; Johansen, 1988). 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:*

$$z_t = y_t - \beta * x_t \tag{11}$$

*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. If the order of integration of the two time series, $x_t$ and $y_t$, is not significantly different, the error correction term ($z_t$) is then computed via an ordinary least square and 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 then 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.

We divide the dataset into two subsamples, 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) to test the hypotheses. For the assessments of volatility correlations (hypotheses 1a and 1b) and of changes in the speed of mean reversion (hypothesis 2a), the Chow (1960) breakpoint test is employed. This test entails using a one-sided *t*-test, whose alternative hypothesis is defined according to the hypothesised direction of change.

### *4.5. 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 (Denmark, Finland, Norway, Sweden, 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 is focused on weekday daily (Monday to Friday) prices (base load prices), 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. These time series are converted to a weekday daily frequency and divided by the daily volume traded on the German spot market in order to create the actual ‘Wind Power’ and forecasted ‘Planned Wind Power’ penetration time series. Table 4.1 summarises the electricity spot prices of the different markets in €/MWh as well as the two wind power penetration time series.

The highest electricity spot prices were observed in EPEX-FR (367.60 €/MWh) and the lowest in Spain (3.13 €/MWh). All variables except OMEL exhibit positive skewness. Excess kurtosis is also positive for all markets indicating fatter tails compared to the normal distribution especially in France.

Table 4.30: Summary statistics – Spot prices & wind power penetration

| | 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. 2.11.2009 to 9.10.2012

Table 4.2 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. Mean average electricity prices, in the different spot markets, range from 45.10€/MWh (Nordpool) to 57.47€/MWh (Swissix) as reported in column 3. The last column contains the estimate for the order of integration i.e. mean-reverting behaviour of the time series, $d$. The highest value of $d$ is observed for EPEX-FR and Nordpool (0.906 and 0.862, respectively). These estimates are close to one and indicate a comparably slow reversion to the mean or, in other words, low reactivity to unexpected supply or demand shocks. The lowest value of $d$ was for spot prices in APX-UK (0.489), which therefore had the fastest speed of mean reversion in the period studied.

Table 4.31: Summary statistics and estimated speed of mean reversion of smoothed data

| | Min | Mean | Max | Std. Dev | Skew. | Kurt. | FELW (m=0.75) |
|---|---|---|---|---|---|---|---|
| **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.) feasible exact local whittle estimator (FELW), prices in €/MWh; 6.08.2010 to 6.08.2012.

### *4.6. Empirical Results and Discussion*

#### *4.5.1. Increased Volatility Correlations in EU Electricity Spot Markets*

Tables 4.3 and 4.4 summarise associations based on the TTDCC model. Estimated correlations before 6 August 2011 are shown in the top triangle of each table, while the correlations after this date are shown in the bottom triangle. The correlation estimates are averages of the time varying coefficients for one year before and one year after. According to the estimates, before the eighth nuclear power plant closures, 11 and 31 out of the 36 correlations are significant at 1% significance level when considering ‘Wind Power’ (Table 4.3) and ‘Planned Wind Power’ (Table 4.4), respectively. The associations between electricity spot price volatilities are all positive. Before 6 August 2011, the estimated correlations of spot price volatilities range from 0.42 (Belpex and Swissix) to 0.84 (Belpex and EPEX-FR) for ‘Wind Power’ (Table 4.3), and for ‘Planned Wind Power’ (Table 4.4) from 0.18 (APX-UK and Swissix) to 0.99 (Belpex and EPEX-FR).

Correlation coefficients after 6 August 2011 for ‘Wind Power’ and ‘Planned Wind Power’ can be found in the bottom triangles of Table 4.3 and 4.4 respectively. Overall, we observe more significant associations after 6 August 2011. The 31 significant (1% level) correlations considering ‘Wind Power’ range from .17 (for APX-NL and OMEL, as well as OMEL and Swissix) to .97 (Belpex and EPEX-FR). Considering ‘Planned Wind Power’, 30 correlations are significant at 1% level and also in the range between .17 (for APX-NL and OMEL) and .97 (Belpex and EPEX-FR).

Table 4.32: Average TDCC correlations –actual wind power penetration.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| 1 EPEX-FR | | .47*** | .61*** | .00 | .20 | .53*** | .12 | .84*** | -.06 |
| 2 EPEX-DE | **.85***** | | .51*** | .10 | .02 | .32* | .03 | .43*** | -.43*** |
| 3 APX-NL | **.86***** | **.89***** | | .16 | .24 | .46*** | .15 | .71*** | -.28*** |
| 4 Nordpool | .33*** | .37*** | .31*** | | .00 | .05 | .18 | -.05 | -.15 |
| 5 OMEL | .26*** | .22*** | .17*** | .10 | | .16 | -.09 | .33* | .04 |
| 6 SWISSIX | .71*** | **.75***** | .73*** | .29*** | .17*** | | -.10 | .42*** | -.11 |
| 7 APX-UK | .24*** | .22*** | .24*** | .07 | .00 | **.21***** | | .15 | .06 |
| 8 BELPEX | **.97***** | **.85***** | .9*** | .30*** | .24 | .73*** | .25*** | | -.06 |
| 9 WindPower | **.41***** | -.56*** | -.48*** | -.29*** | -.08 | -.31*** | -.15*** | **-.30***** | |

Average TDCC coefficients of electricity spot prices and actual wind power penetration before 6 August 2011 (top triangle) and after 6 August 2011 (bottom triangle). *, **, *** 10%, 5% and 1% significance level; significant changes of TDCC coefficients before compared to after printed in bold

Table 4.33: Average TDCC Correlations – planned wind power penetration

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| 1 EPEX-FR | | .68*** | .79*** | .28*** | .22*** | .59*** | .21*** | .99*** | -.14*** |
| 2 EPEXDE | **.84***** | | .82*** | .39*** | .12** | .54*** | .21*** | .68*** | -.48*** |
| 3 APX-NL | **.86***** | **.89***** | | .35*** | .16*** | .64*** | .25*** | .80*** | -.42*** |
| 4 Nordpool | .34*** | .37*** | .32*** | | .00 | .25*** | .19*** | .29*** | -.20*** |
| 5 OMEL | .25*** | .22*** | .17** | .11 | | .24*** | -.02 | .22*** | -.01 |
| 6 SWISSIX | **.71***** | **.75***** | .73*** | .29*** | .17 | | .18*** | .60*** | -.25*** |
| 7 APX-UK | .24*** | .21*** | .23*** | .07 | .00 | .21*** | | .22*** | -.11 |
| 8 BELPEX | .97*** | **.85***** | .90*** | .31*** | .24*** | **.73***** | .25*** | | -.15*** |
| 9 PlannedWind Power | -.40*** | **-.54***** | -.45*** | -.30*** | -.09 | -.29*** | -.14*** | **-.37***** | |

Average TTDCC coefficients of electricity spot prices and planned wind power penetration before 6 August 2011 (top triangle) and after 6 August 2011 (bottom triangle). *, **, *** 10%, 5% and 1% significance level; significant changes of TDCC coefficients before compared to after printed in bold.

Compared to other markets, Nordpool and OMEL exhibit relatively fewer significant correlations, which are also smaller. For example, in Table 4.3, before 6 August 2011 (top triangle), OMEL's spot prices were independent of the other markets. After 6 August 2011 (lower triangle), significant correlations are low (between .17 and .26). This finding is likely to reflect OMEL's price caps (0-180€/MWh) and limited physical connection with other markets. In particular with France, interconnection represented only 3% of Spain's electricity generation (Bilbao et al., 2011). Nordpool, by contrast, is better connected but also more resilient to volatility shocks because of its large capacity of flexible hydro-based electricity (Deidersen and Trück, 2002).

One tailed t-tests where used to assess a structural break in the correlation coefficients: seven (Table 4.3) and eight (Table 4.4) of the estimated correlations have increased when comparing the estimates before 6 August 2011 (top triangle) with those after 6 August 2011 (bottom triangle) for 'Wind Power' and 'Planned Wind Power', respectively. The correlations that increased significantly are highlighted in bold.

The correlations between wind power penetration and spot price volatilities (right column and last row) are generally negative: the number of significant associations with 'Wind Power' (Table 4.3) increased from two (right column) to seven (last row) when one compares the period before to after 6 August 2011. However, only two significant increases are observed, as highlighted in bold. Similarly, for 'Planned Wind Power' (Table 4.4) there are significant associations before and after 6 August 2011, between wind power penetration and spot price volatility in all markets except OMEL (before and after) and APX-UK (after). The strength of association increased significantly (5% significance level) in the cases of Belpex and EPEX-FR, when comparing the respective values in the top triangle (right column) to the bottom triangle (last row). In general, the stronger associations when 'Planned Wind Power' is somewhat expected, as electricity spot prices are set before gate closure, thus implying that forecasts, rather than actual metered output, are more likely to affect the spot price (Gil et al., 2012).

The EDCC models, whose estimated correlations are displayed in Tables 4.5 and 4.6 as in previous tables, confirm the above results. For example, the strength of negative correlation between wind and electricity spot price volatility in EPEX-FR has more than doubled for 'Wind Power' and 'Planned Wind Power' from the earlier -0.18, in both cases, to -0.43 (Table 4.5) and -0.42 (Table 4.6) respectively. In EPEX-DE, the correlation between spot prices and 'Wind Power' increased significantly from -0.42 to -0.58 (Table 4.5). Likewise, in the case of Belpex, we observe significant increases from -0.18 to -0.41 for 'Wind Power' (Table 4.5) and -0.18 to -0.39 for 'Planned Wind Power' (Table 4.6). OMEL remains the exception.

Table 4.34: Average EDCC correlations –wind power penetration

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| 1 EPEX-FR | | .71*** | .83*** | .26*** | .21*** | .58*** | .19*** | 1.00*** | .18*** |
| 2 EPEX-DE | **.84*** ** | | .83*** | .39*** | .11* | .54*** | .19*** | .71*** | -.42*** |
| 3 APX-NL | .86*** | .88*** | | .32*** | .15* | .65*** | .23*** | .84*** | -.40*** |
| 4 Nordpool | .29*** | .34*** | .27*** | | .01 | .22*** | .21*** | .27*** | -.19*** |
| 5 OMEL | .24*** | .20*** | .15*** | .09 | | .20*** | -.01 | .20*** | .01 |
| 6 SWISSIX | **.69*** ** | **.72*** ** | .70*** | .27*** | .16** | | .15*** | .58*** | -.26*** |
| 7 APX-UK | .25*** | .23*** | .24*** | .08 | -.02 | .20*** | | .20*** | -.11* |
| 8 BELPEX | **.97*** ** | **.84*** ** | .90*** | .26*** | .22*** | **.71*** ** | .26*** | | -.18*** |
| 9 Wind Power | **0.43*** ** | **-.58*** ** | -.49*** | -.28*** | -.08 | -.31*** | -.15*** | **-.41*** ** | |

Average EDCC correlations of electricity spot prices and actual wind power penetration before 6 August 2011 (top triangle) and after 6 August 2011 (bottom triangle). *, **, *** 10%, 5% and 1% significance level; significant changes of EDCC coefficients before compared to after are printed in bold.

Table 4.35: Average EDCC correlations – planned wind power penetration

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| 1 EPEX-FR | | .72*** | .84*** | .26*** | .20*** | .58*** | .19*** | 1.00*** | -.18*** |
| 2 EPEX-DE | .84*** | | .83*** | .39*** | .10 | .54*** | .20*** | .72*** | -.46*** |
| 3 APX-NL | .86*** | .88*** | | .32*** | .15*** | .65*** | .23*** | .84*** | -.42*** |
| 4 Nordpool | .30*** | .34*** | .28*** | | .01 | .22*** | .20*** | .26*** | -.20*** |
| 5 OMEL | .24*** | .20*** | .15** | .09 | | .20*** | -.01 | .19*** | -.01 |
| 6 SWISSIX | .68*** | **.72*** ** | .70*** | .28*** | .16*** | | .15*** | .59*** | -.28*** |
| 7 APX-UK | .25*** | .22*** | .24*** | .08 | -.02 | .20*** | | .20*** | -.10* |
| 8 BELPEX | **.97*** ** | .84*** | **.90*** ** | .27*** | .22*** | **.71*** ** | .26*** | | -.18*** |
| 9 Planned Wind Power | **-.42*** ** | -.55*** | -.46*** | -.29*** | -.09 | -.29*** | -.15*** | **-.39*** ** | |

Average EDCC correlations of electricity spot prices and planned wind power penetration before 6 August 2011 (top triangle) and after 6 August 2011 (bottom triangle). *, **, *** 10%, 5% and 1% significance level; significant changes of EDCC coefficients before compared to after are printed in bold.

Following greater price risks in electricity spot markets, an upsurge in the volume traded in forward markets would be expected. Month-ahead German base load data obtained from Tullett Prebon Information from August 2010 to August 2012 showed significant 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

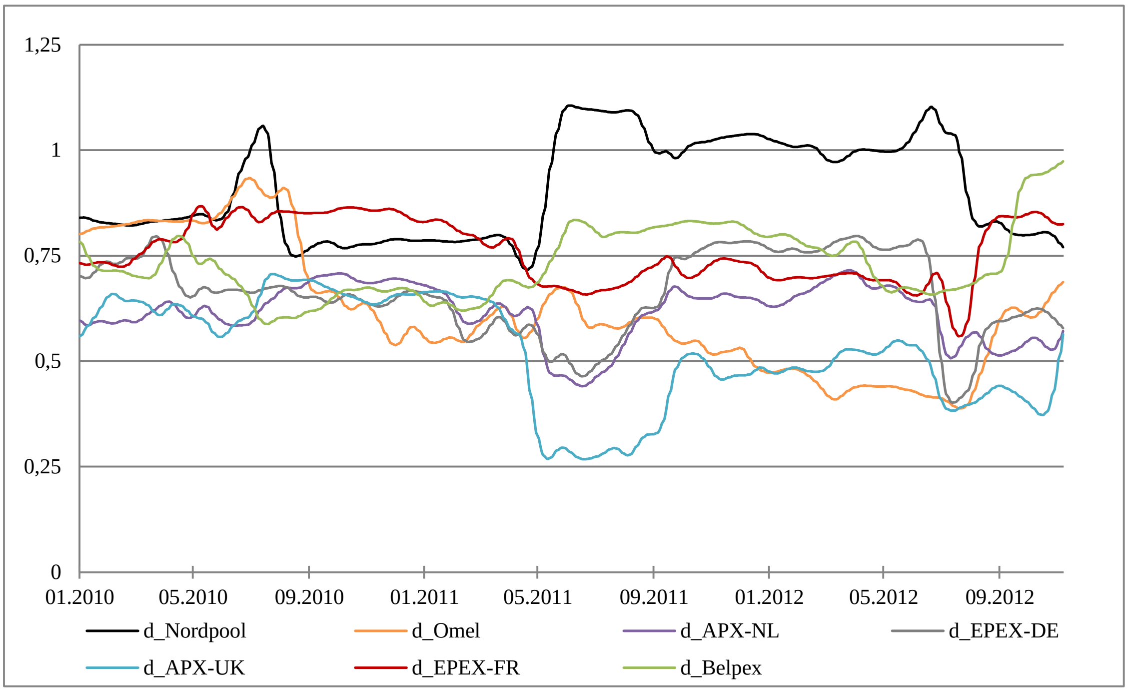
German moratorium was announced, one-month-ahead prices of base load moved from their mean average of 50.3€MWh to 62€/MWh. However, in the next few month prices converged towards 40€/MWh. Furthermore, despite an increased demand for base load contracts, a decrease in the average price per MWh paid from an average of 52.3€/MWh to 48.53€/MWh is observed when comparing one year before with one year after 6 August 2011. Similarly, when comparing one month forward data provided by Platts for the Dutch, French, German and the GB market we observe a decrease of average month ahead prices comparing one year before with one year after for all markets except the GB. For example the average French month ahead prices were 64.71€/MWh one year before the closure and reduced to 60.68€/MWh in the year after. Only in the GB market the average forward data increased by 0.23€/MWh to 62.24€/MWh. These price developments confirm that the German capacity reduction was offset by rising shares of RES-E.

Overall, the results show that volatility correlations of spot prices across EU electricity markets as well as the associations between spot price volatilities have increased in some, but not all markets studied. Changes are more noticeable when considering ‘Planned Wind Power’ rather than actual ‘Wind Power’. We therefore find some support for hypothesis 1a, which stated that after Germany’s nuclear power station closures, associations of electricity spot price volatilities increased. Before 6 August 2011, fluctuations of ‘Wind Power’ and ‘Planned Wind Power’ were either independent of electricity spot price volatility or the correlations were lower than after 6 August 2011. Given this pattern, there is some support for hypothesis 1b, since most associations between wind power penetration and electricity spot prices became stronger after 6 August 2011.

### *4.5.1. Changes in Mean Reversion in the Spot Market*

Figure 4.2 depicts the time-varying estimates of the order of integration (*d*) of electricity spot prices in the period between January 2010 and October 2012. It suggests that following the incidents at Fukushima in March 2011 and the closure of the eight German nuclear plants (6 August 2011), the mean-reverting behaviours of electricity spot prices in connected liberalised European electricity markets changed. In the Nordpool, a decrease in the speed of mean reversion (increasing values of the parameter *d*) can be observed briefly after March 2011. An abrupt drop in the order of integration for the British market can also be seen soon after April 2011, which indicates a faster speed of mean reversion that might be explained by the greater competitiveness, in the period, of flexible gas-generated electricity due to low fuel costs (European Commission, 2011b). In summary, there are signs of divergence in electricity price dynamics in the second quarter of 2011 which will be further investigated.

Figure 4.36: Order of integration *d* of electricity spot prices




Time-varying order of integration *d* between January 2010 and October 2012. Rolling window size 200 and output smoothed with HP filter ($\lambda = 250$)

The sample means of the estimated *ds* of the perturbed price series, their confidence intervals and the results of the *t*-tests are summarised in Table 4.7, and confirm the above observations that were based on Figure 4.2. According to one-sided *t*-tests, the parameter *d* has increased for all markets, except OMEL and APX-UK, at a 5% significance level. For OMEL, there is no significant change in the parameter *d* and for APX-UK there is a decrease. All in all, hypothesis 2a is supported by most markets: the speed with which electricity spot prices revert to their mean has decreased in those markets that are connected to the German electricity market in the period examined.

Table 4.36: Estimated order of integration - one year before and one year after 6 August 2011

| | | $\bar{d}$ and CI | 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 *d* before and after 6 August 2011.The asterisks *, ** and *** denote 10%, 5% and 1% ´-significance levels of t-tests assessing statistically significant changes respectively.

### *4.5.2. Changes in Convergence of Electricity Spot Prices*

Since the speed with which prices revert to their mean has changed for all markets except OMEL and APX-UK, the process of convergence to a common price may have been affected. Table 4.8 presents *t*-statistics assessing the Null hypothesis of a common order of integration for pairs of markets before (above diagonal) and after (below diagonal) 6 August 2011. It shows that before 6 August 2011, 20 market pairs had a common order of integration, as the Null hypothesis of equal values is not rejected. After 6 August 2011, eleven market pairs (as shown below the diagonal in Table 4.6) had equal values of *d*. No market had a common order with APX-UK, thus highlighting different price dynamics between the British and the other EU spot markets.

Table 4.9 reports the estimated order of integration *d* and the standard error of the error correction term for all market pairs that have previously been found to have a common order of integration. If the Null hypothesis of a common order of integration of the parent series (Table 4.8) was rejected, the series cannot be cointegrated and thus were excluded from further assessments. Moreover, the order of integration of the error correction term needs to be significantly smaller than the order of the parent series to confirm cointegration. The *t*-test results in Table 4.9, where significant differences at 5% level are indicated by asterisk, show that before 6 August (top triangle), five market pairs were integrated, but after this date (bottom triangle) there are nine pairs with common long-run dynamics (order of integration *d* is not statistically different). However, the pairs differ: after 6 August 2011, no market was integrated with EPEX-DE, while before that date two were. Overall, we reject the hypothesis of less integration within EU electricity spot markets, but there are indications of a decoupled German electricity market after the nuclear plant closures. It is also noteworthy that no other market shared common long-run dynamics with APX-UK, neither before nor after 6 August 2011.

Table 4.37: 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 that the t-statistic assessing changes in the order of integration d before compared to after was significant at 5% significance level.

Table 4.38: Cointegration tests 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 APXUK | | | | | | | | |

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 that the t-statistic assessing changes in the order of integration d before compared to after was significant at 5% significance level.

### 4.6. Conclusion

This study has applied econometric analysis to show that energy policies implemented by one European member state can impact on electricity price convergence and short run associations. The empirical results show that the share of intermittent RES-E can no longer be neglected in studies of electricity market integration. The focus was on the speedy introduction of the German Nuclear-Phase-Out Act that led to the closure of eight nuclear plants in less than six months after its announcement. In the year that followed, Germany maintained its position as a net exporter of electricity, despite a significant reduction in secure nuclear base load capacities by mostly compensating base load loss with increased wind power generation. The German electricity market has extensive grid connections with its neighbours and has been part of the Central West European market coupling since November 2010. Following the increasing shares of intermittent RES-E in the German system, it was tested if:

H1a: *After Germany's nuclear power station closures in 2011, correlations of spot prices across EU electricity markets increased.*

And:

H1b: *Following Germany's nuclear power station closures in 2011, stronger associations between wind power penetration and spot price volatilities are observed.*

This hypothesis was partially supported by the data, since physically well-connected or coupled electricity markets, except the Nordpool, were subject to significant and positive associations of volatilities which increased after the closures of the nuclear power plants.

Associations between the variances of wind power penetration and spot prices were found to be significant and negative, not only in the German market but also with most other electricity markets that are well connected. Given the observed changes in spot price behaviour in the short run, there may also be consequences in the long run dynamics and in the convergence of EU electricity spot prices. We tested:

H2a: *After Germany's nuclear power station closures in 2011, the speed with which electricity spot prices revert to the mean has decreased.*

And:

H2b: After *Germany's nuclear power station closures, less integration between EU electricity spot markets is observed.*

During the year after the closure of Germany's nuclear plants, results indicate that supply and demand shocks were less easily overcome in the different spot markets. 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. The change in mean reversion suggests that electricity market integration in the EU may have been affected. However, in spite of a decoupled German spot market, more markets were found to be integrated after August 2011. Hence, hypotheses 2a and 2b were not fully supported by the data.

The study has attempted to bring together three streams of literature on the development of liberalised electricity markets by focusing not only on the long-run association between markets, but also addressing the short-run price dynamics and wind power penetration on the spot price dynamics in the local and connected markets. The findings of the study suggest an increased level of correlations as well as decreased ability of most markets to overcome shocks, despite strong price convergence in the period studied. The evidence from the study therefore extends Traber and Kemfert's (2011) study on the German market to interconnected markets: liberalisation and international competition might not be enough to accommodate increasing shares of RES-E to the European electric system. The findings of this study therefore question to Bask and Widerberg's (2009) conclusion for Nordpool of a positive association between price resilience and market integration.

Given the intermittent nature of wind power, the results confirm the importance of reliable wind power forecasts for market operators and players in the spot market. Moreover, it suggests that in interconnected electricity spot markets, forecasts of wind power in neighbouring markets should also be taken into consideration by market players. In fact, a limitation of the present study is that it does not consider wind power penetration in the Nordpool and we may only theorise that the stronger resilience of its spot prices might be associated with it having a more balanced electricity mix. Given the targets for wind power in Europe, future studies of electricity market integration should address wind power penetration in the different markets, as this study has shown that local increases in wind power penetration affect regional price behaviour.

The present study highlights the challenges associated with isolated energy policies while achieving the goal of a single European electricity market and RES-E targets and calls for co-ordinated European approach to energy policy. To secure the necessary level of investment in the electricity sector, decisions that may impact on electricity mixes should be assessed at the regional and local levels.

### *4.7. Summary*

The focus of the third study was to assess the implications of Germany's altered electricity mix and capacity level for electricity market integration. The research question addressed in this study was:

*How does an increased level of renewable electricity impact on electricity price dynamics and on market integration?*

First, changes in short run dynamics for eight European electricity markets and a wind penetration variable were investigated using a dynamic MGARCH. The assessment compared correlation estimates before and after the closure of eight nuclear power plants in Germany by August 2011. Thereafter, time varying fractional cointegration analysis was employed to assess changes in common long run dynamics for electricity markets.

The study found several significant short run associations for the European electricity markets and Germany's wind penetration variables. These associations were found to be stronger for the planned compared to the actual wind penetration variable as well as one year after compared to one year before the closure of the nuclear power stations. The findings extend previous research which addressed associations of renewables for electricity spot price behaviour, as the assessment was not limited to one market. It was highlighted that wind generated electricity is negatively correlated with electricity spot prices locally as well as in interconnected markets. This means that although the decision over a countries electricity mix is national, the choice is likely to be relevant for the electricity price behaviour in other electricity markets. The magnitude of common short run associations was found to be dependent on geographic proximity, as well as on the level of interconnectivity. Policy makers should consider these findings when making decisions over their national electricity mixes and plan and align their generation portfolios in order to make use of complementarities of different natural endowments. It is noteworthy that it is not possible to infer causality from this assessment, even though it can be assumed that electricity prices are endogenous to wind penetration levels and not vice versa.

The second important finding relates to convergence of electricity markets. The results from a fractional cointegration analysis before compared to after the closure of eight nuclear power plants, indicated that Germany has decoupled from the common European electricity market, as it no longer shared any common long run dynamics with any other market. Overall, however, has the number of converging markets remained constant. This indicates that European electricity market integration is robust to changes in the electricity mix and supports the idea that an integrated electricity system can integrate large shares of renewable energies more easily compared to isolated markets. However, when considering the speed with which prices revert to their mean after compared to before the nuclear phase out it is noticeable that price resilience has significantly deteriorated for seven out of eight European electricity markets after the closure of the nuclear power plants in Germany. This means that sudden supply or demand shocks are less easily overcome after the nuclear phase out compared to before, despite the fact the number of integrated markets has remained the same. The main implication for policy makers is therefore that convergence of electricity prices should be monitored together with developments of market resilience.

## 5. Summary and Conclusion

This PhD thesis set out to evaluate both the status quo and the evolution of electricity market integration in the EU. In the introduction to the thesis, the motivation for creating an internal market for electricity was discussed. Previous assessments of electricity market integration were then reported and criticised and the contextual background of the study, including the legal framework, electricity trading arrangements and electricity mix in the European markets were detailed. The possible drivers of electricity wholesale prices and how they may affect common price dynamics were highlighted, leading to the overall research question of the doctoral research:

*Are liberalised European electricity markets converging into a single internal market for electricity?*

Three associated research questions were addressed in three empirical studies. A time-varying fractional cointegration analysis was employed to assess the first research question in chapter two:

1. *How has electricity market integration evolved over time and what factors drive convergence and divergence of electricity prices in the EU?*

By linking electricity market integration and resilience, the theoretical framework of the existing literature was extended by the research. Market resilience reflects security of supply which is a main objective for integrating electricity markets. Increased market resilience indicates higher reactivity to unexpected shocks in the electricity supply system. Signs of greater market integration and market resilience over time were found in the forward markets, but not in the spot markets.

The time-varying assessment of integration in European electricity markets further identified causes for departures from common long-run dynamics in wholesale markets, such as changes in demand (e.g. public holidays) and supply (e.g. plant failure, or strikes). These were found to be relevant for spot but not for forward markets. Moreover, the study also extended our knowledge of how electricity price dynamics in an integrated system respond to special events that alter system capacity, such as a new interconnector, market coupling, or Germany's energy transition. Additional interconnector capacity was found to increase electricity market resilience against external supply and demand shocks, especially in the market that was previously more isolated. Market coupling was also positively associated with electricity price behaviour in the markets that were part of market coupling, but surprisingly, in the case of the TLC and CWE coupling, also in markets that were not connected. The assessment of Germany's Energiewende, which compared long-run price dynamics one year before and one year after the closure of eight nuclear power stations, suggested that the reduction in secure base load capacities had a negative impact on the resilience of electricity spot markets that were directly connected to Germany. A limitation of this particular study might be that, besides electricity prices, other variables whose potential relevance has been stressed in the introduction (e.g. wind power penetration in adjacent markets, fossil fuel input prices) were not included in the empirical assessment.

The second study, reported in the third chapter, therefore considered the context of different electricity mixes. The focus was on the association between wholesale electricity prices and fuel and carbon price developments. Their impact on electricity market integration was investigated. Three markets (France, GB and Nordpool) were chosen because of significant differences in their electricity mix and level of interconnection. The research question was:

2. *How do fuel and carbon prices associate with electricity prices and do they affect electricity market integration?*

Convergence with interconnected or coupled markets was assessed, as well as fuel and carbon prices for periods when the price series followed a trend. The results of the investigation confirmed the association between the local electricity mix and interconnectivity of a market for price convergence. The British market, which had the lowest share of imports and exports compared to total domestic electricity output, was found to be less integrated with other markets. Wholesale electricity price dynamics in Britain were mostly associated with fuel inputs to electricity generation, and the correlation with carbon prices changed depending on the fuel share in the electricity mix. In the Nordpool and French markets, the opposite was observed. The results of the study highlighted the strong association between the local electricity mix, interconnectivity and electricity price convergence.

Increased shares of domestic RES-E have often been proposed as a means to decrease fuel price dependency, especially when a local power sector relies on foreign imports. However, the second study showed that electricity market integration could also weaken the fuel–electricity price nexus.

In Europe, a main consequence of diversifying the electricity mix in the light of emission targets is the increased shares of RES-E in the power system. The share of intermittent electricity is growing while markets are expected to become more integrated. A limitation of the second study was that intermittent RES-E have not been included in the empirical assessment. Increasing shares of RES-E and market integration were analysed in more detail in the third study:

3. *How does an increased level of renewable electricity impact on wholesale electricity price dynamics and on electricity market integration?*

The investigation showed that after the closure of eight German nuclear power plants, associations of electricity spot price volatilities increased in most markets that were well connected to the German market. Furthermore, in the long run, prices were found to be less resilient against supply and demand shocks in Germany but also in interconnected markets. Only for the British and Spanish markets, which have the weakest cross-border transmission networks and no direct interconnection to Germany, were the price dynamics unaffected. In the case of Spain, a further reason might be the restrictive price cap between 0 and 180€/MWh. Overall, compared to before the closure of the German nuclear capacities, more markets showed common price dynamics, but the German market was no longer integrated with any other market. The finding therefore highlights why, besides market integration, market resilience – one main motivation for market liberalisation – should also be considered. The increased level of RES-E had adverse implications for electricity market resilience but not for market integration.

This last study added to the existing literature in several ways. First, two wind variables were included in the assessment, capturing the effect of intermittent RES-E on common price dynamics. Second, whereas previous research focused mainly on price levels within single markets, short-run associations between electricity prices, as well as between the wind variables and electricity prices, were investigated by analysing the dynamic correlation coefficients of the volatilities. Third, besides the altered price dynamics, changes in convergence before and after the closure of the nuclear stations were observed.

As a whole, the three studies of the doctoral research contribute to the existing literature by showing that electricity market integration in Europe is changing over time and is subject to factors, such as market shocks, fuel price developments and the electricity mix. Empirical results of the studies suggest that a fully integrated market for electricity was not achieved by March 2013. The thesis highlighted the consequences of interconnector capacity, market coupling and Germany´s nuclear phase out on market resilience, a main motivation for integrating electricity markets. Accordingly, there appear to be some positive advances following measures aimed at integrating European electricity markets. However, the German case also indicated that a change in the local electricity mix could adversely affect the aim of market integration. A policy dilemma was thus highlighted. In general, electricity prices reverted more quickly to their normal levels after an unexpected event that caused supply and demand mismatches the more integrated the markets were. However, a repercussion of market integration is that markets that are well integrated are also more exposed to energy policies outside their borders. Despite a common legal framework for integrating liberalised electricity markets in the EU, decisions on reserve capacities or electricity mix are made at the national level. This means that projected insufficient capacity margins, anticipated for example in Britain and Belgium, are a concern for market operators and participants not only in the respective markets but also in interconnected markets (Kunsch and Friesewinkel, 2014). Together with the planned increases of RES-E until 2030, which require flexible backup capacities to smooth some of the intermittent output, the results of this study call for a joint assessment of reserve capacities and greater sharing of information while planning future generation and transmission.

There are several areas for future research that could extend the findings of the studies. First, a general limitation of the first and second studies is the pairwise assessment of price convergence. It would be interesting to assess multivariate convergence to investigate patterns in convergence and divergence.

Second, the first study assessed changes in market resilience after market coupling and additional interconnector capacity, and could be extended with an assessment of changes in price convergence. So far this has only been conducted for Germany's energy transition, as detailed in the fourth chapter.

Third, the two main methods for time series analysis used in this research, which are fractional cointegration and localised autocorrelation functions, lend themselves to an assessment of their commonalities and differences.

We leave these paths open for future research.

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