DEREGULATED WHOLESALE ELECTRICITY PRICES IN EUROPE

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Abstract. This paper analyses the interdependencies existing in the European electricity prices. The results of a multivariate dynamic analysis of weekly median prices reveal the presence of strong integration (but not perfect integration) among the markets considered in the sample and the existence of a common trend among electricity prices and oil prices. This implies that there are no long-run arbitrage opportunities. The latter result appears to be relevant also in the context of the discussion of efficient hedging instruments to be used by medium-long term investors.

Keywords: European electricity prices, Cointegration, Interdependencies, Equilibrium Correction model, Oil prices.

JEL classification: C32, D44, L94, Q40.

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1. Introduction

Following reforms introduced in the organization of electricity markets almost everywhere, electricity prices are now determined in regulated (generally, Pool) markets where prices are strongly affected by the impossibility to arbitrage between time and space. As a result these prices have become very volatile. Yet, time series of current electricity prices differ quite substantially from prices determined in markets for financial assets and other type of commodities since electricity cannot be treated like a stock. Electricity prices have specific and somehow unique characteristics (e.g. multiple seasonalities, spikes, heteroschedasticity, periodicities) that motivate the use of appropriate time series modelling to study the specific features of their time pattern and to evaluate how prices are affected by temporal demand-supply imbalances, seasonality, transmission congestion and, to a lesser extent, by the features of the mechanism that generates the data (type of auction employed, price rule, degree of market concentration, etc.). In Europe the reorganization of the electricity sector started with the establishment of the England and Wales Pool market in 1991 and it is still ongoing. The newly created European national markets show several similarities in the architecture of the market and quite significant differences in the conditions affecting consumption as well as generation technology. Despite the existence of physical interconnections that allows a significant cross-border trade among countries, so far European prices series have been studied ignoring the issue represented by a possible interdependency in the dynamics of prices formed in (at least) neighboring markets. Indeed, to our knowledge no study to date has examined electricity price interdependencies at the European level. Filling this gap is the primary motivation of this paper. In order to do so, we conduct a multivariate dynamic analysis of prices generated by four major European electricity pools (Germany, France, Austria, Netherlands). Consistently with previous analyses, European data inspection reveal the presence of spikes and jumps, heteroschedasticity and strong seasonalities. We therefore make use of estimators and tests robust to departures from gaussianity, homoschedasticity and stationarity in differences. Our results question the most commonly reported finding of mean reversion and, implicitly, of no integration of European prices. On the contrary, our tests indicate the presence of strong integration among the four markets and the presence of a common trend among electricity prices. We found that this common trend is in turn cointegrated with the oil price. The latter result appears to be relevant also in the context of the discussion of efficient hedging instruments to be used by medium-long term investors.

The paper is organized as follows. In section 2 we present the main characteristics – both institutional and technical – of some wholesale

European markets for which data are available. In section 3 a review of previous works on time series analysis of electricity prices is discussed. In section 4, which is divided into subsections, we present the empirical models and the main results. Section 5 concludes.

2. The European electricity markets

In this section we describe some characteristics of the European electricity exchanges considered in our sample: Nord Pool, Austria, France, Germany, Netherlands for a sample period ranging from March 2002 to June 2006. Spain and Italy are also considered for reference since they present some specific characteristics. We emphasise the features of each national electricity industry and the effects produced by the two European Electricity Directives (1996 and 2003) that indicated the general prescriptions for the reorganisation of the industry.

Electricity market reform has been first introduced in Chile (1987) and since then it has spread to many areas of the world. The England and Wales (E&W) Electricity Pool market (1991) is the first European experience that completed the liberalization of the British electricity industry. More generally the liberalisation of the electricity industry followed a number of key steps: the unbundling of previously vertically integrated activities (generation, transmission, distribution and retail supply); the introduction of new institutions such as wholesale and retail competitive markets, with free entry of generators and suppliers; the creation of an independent national regulator who guarantees third party network access to the (still monopolised) transmission and distribution lines. Privatisation of vertically integrated monopolistic suppliers previously existing, was not explicitly required by the two European Directives[1]. Both the EU Directives focused on the unbundling of the industry to separate the potentially competitive generation and supply activities from the natural monopoly activities (transmission and distribution). The second Directive (2003) in particular introduced a stronger regulation of access to networks and set a minimum standard timetable for the full opening of local markets.

The reorganisation and new regulation of the electricity industry have been driven by some major developments in the technology that took place in the 70s and 80s. First we should mention the introduction of new combined-cycle gas turbines (CCGT) plants that are relatively small sized (350 MW to 450 MW), have short constructions times and require a small investment. Moreover, CCGT units are highly efficient and have lower marginal costs than old open-cycle gas turbine plants. It follows that old gas plants are used for peak hours and to provide reserve, whereas CCGT plants can be used in hours of low demand. Notably, they compete in the most profitable portion of supply, namely

[1]UK and Portugal have realised extensive privatisation programs whereas in Italy we had only partial privatisation. France maintains a public ownership structure.

the base-load, previously dominated by hydro and nuclear production. Both hydro and nuclear plants created a strong barrier to competition since they are capital-intensive and are constrained respectively by the location and the national legislation. CCGT plants have been considered to break the barriers to new entry in the industry. These technological innovations attracted new investment in the generation industry and rendered the generation of electricity potentially competitive.

The presence of new independent power producers alongside the old (ex)monopolist, introduced a problem of coordination between time varying demand and supply of a physical good like electricity which is not storable. Coordination was not an issue in the old integrated industry where the sole producer was also responsible for transmission and distribution and was endowed with all the relevant information about demand and supply. Therefore the new liberalised market structure requires a central mechanism to be introduced in order to continuously match demand and supply. In the countries considered in our sample the exchange of physical electricity is organized as a competitive wholesale spot market or wholesale auction. The introduction of a wholesale market of electricity poses some problems of market architecture and design to regulators and it has also stimulated sophisticated theoretical research. In the first place, it must be decided whether to opt for a centralized Pool or for a decentralized market. In the first case, all the electricity must be allocated through a mandatory Pool; this implies that bilateral contracts are not allowed. All operators, both on the demand and on the supply side, submit hourly bids (half-hourly bids in the old UK&W Pool) and the market operator allocates quantities by a procedure that minimizes the cost of despatch. A decentralized electricity market like NETA (UK after 2001), on the contrary, is organized as a series of bilateral forwards and future markets with a number of power exchanges for voluntary trading which are open until shortly before delivery. The advantages of a Pool market over a decentralized one is that demand and supply are continuously matched so that all coordination problems disappear. Advocates of the decentralized market structure emphasize, however, that the Pool may be affected by strategic bidding on the part of those operators having some market power and, as a consequence, the Pool prices do not generally reveal costs. Whilst the issue is still open at the theoretical level, on the empirical side we find many examples, especially in Europe, of non-mandatory electricity Pools where bilateral contracts are allowed. This choice is probably motivated by the desire to capture the main advantages of the two alternative organization schemes. Electricity markets considered in our paper are all non-mandatory. Producers and consumers/distributors are allowed to engage in bilateral contracts for the short or long term exchange of electricity. The quantity traded bilaterally is usually included in the total supply recorded in the exchange as zero price offers. Due to this characteristic, the degree of liquidity of the Pool market, is defined as the ratio between electricity traded in the Pool and the total electricity supplied.

All the electricity Pools we consider work as multi-unit uniform price auctions: generators and buyers submit price/quantity offers which are aggregated by the market operator in order to form a supply curve and a demand (where demand side bidding is allowed) respectively. The equilibrium price and quantity are then determined by the standard crossing condition. Producers who bid a price less or equal to the equilibrium price are included in the production program for the next day. The total quantity sold by all despatched units is paid the equilibrium System Marginal Price (SMP) defined as the bid made by the marginal unit selected by the mechanism.

The exchanges we consider work first on a day-ahead basis. Day-ahead markets are mainly designed for planning purposes and, as the time of delivery gets closer, positive or negative deviations from the planned production are managed in a number of fine-tuning markets. These fine-tuning or intra-day markets are of considerably smaller size than the day-ahead market. In the real time, it is the transmission system operator who is responsible for the balance of demand and supply.

A second common characteristic of European exchanges considered is the existence of demand side bidding. However, the opening of the bidding process to demand has not proceeded at a common pace in all countries. Indeed, following the European Directive 2003/54/EC, all customers have to be considered as eligible by 1/7/2007. At present, however, in almost all markets considered, only large (mainly industrial) consumers and distributors are allowed to present the demand bids.

The EU Electricity Directive 2003/54 requires each country to implement both legal and functional unbundling for transmission and distribution System Operators. This rule is expected to lead to non-discriminatory network access with tariffs broadly reflecting costs. Although the provisions of the Directive have usually been transposed into national laws, it is not clear whether network companies have yet modified all aspects of their organization to comply with the new law. The requirement to have legally unbundled and independently managed transmission system operators (TSO) should have been implemented by 1 July 2004. All the countries considered have accomplished to the legal unbundling of network operators, but in some cases there is still overlap between ownership of the TSO and ownership of one (usually the former monopolist) electricity supplier.

The auction-based dispatching does not take transmission conditions into account and so congestions may occur both in the internal market and across-border. The main features of the mechanisms implemented to manage congestions is that they are market-based. When internal congestion occurs on the transmission line the market operator together with the TSO try and relieve it at the minimum possible cost in a market based way. However, the allocation of the congestion costs may be performed in more than one method. One substantial difference depends upon whether or not locational prices are calculated directly in the electricity day-ahead market. Alternatively, separate markets for the congestion management may be implemented when the day-ahead market allocations result unfeasible. Zonal prices prevailed in the Nord Pool and in Italy. Zonal pricing is thought to combine a good performance in sending signals to the market together with a fairly simple implementation. The resolution of bottlenecks is managed by the splitting of markets into zones characterized by different equilibrium prices. In the congested area the price is higher than the one prevailing in the non-congested area. The determination of the different zones is managed differently across markets. For example, within Norway and at the interconnections between the Nordic countries price mechanisms are used to relieve grid congestion (bottlenecks) resulting in different Elspot area prices. In Austria, which is an important transit country, congestion on the network occurs because of a high quota of energy that goes through the lines in order to be delivered abroad. Therefore, the network capacity in this country is extremely valuable and as a result network access tariffs are settled at the highest level with respect to other countries. On the contrary, within Sweden, Finland, and Denmark, grid congestion is managed by counter-trade purchases based on bids from generators.

The electricity markets considered differ significantly in their underlying production structure. This is a very important point since all the issues related to the market design become less severe when the industry is more competitive. It is well known that electricity can be generated in a variety of ways and using different types of input, which can be either renewable or not-renewable. The cost of the unit of energy supplied in a country depends upon the market size and the different kinds of plants producing in a given hour. The shape of the system marginal cost function is therefore influenced by the productive mix of the generating industry. On the other hand the technological features are also thought to influence the market power of firms, their strategic behaviour and consequently the SMP. For that reason some data about the industry structure must be considered into the analysis. Figure 1 contains data on generation sources in the European countries considered in the sample.

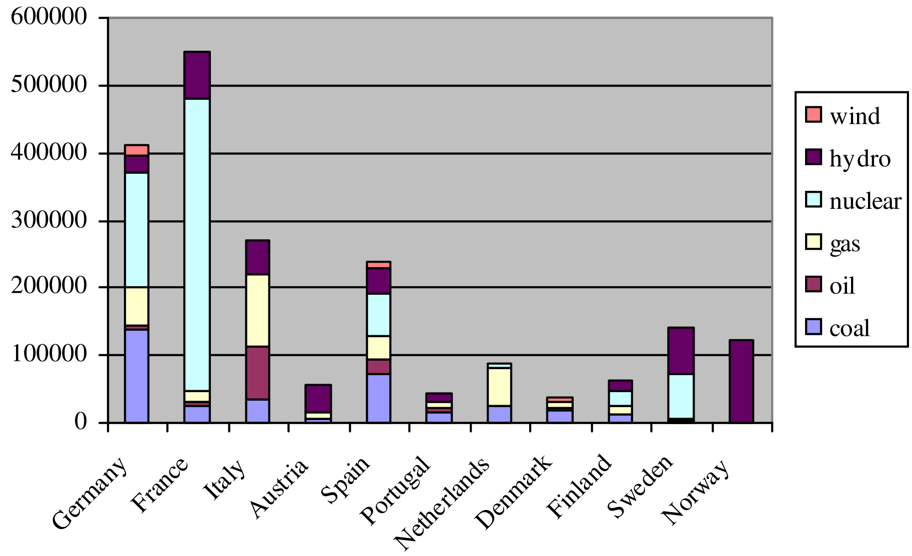

FIGURE 1. Data on production technologies (average 2000-2004)

The Nord Pool comprises the last four countries listed in Figure 1; it links together Norway, which is the founding country (1993), Sweden, who joined in 1996, Finland (1998) and the western part of Denmark (1999). We notice that an high percentage of Nord Pool's total production is generated by hydro and nuclear plants with limited recourse to gas and coal. In the Austrian market hydro plants cover on average the 69% of total production. Germany, Spain, Sweden and especially France have a large nuclear production whereas Spain and France present similar figures on hydroelectric production. Netherlands and Germany have a small quota of hydroelectric production. Finally, Italy and Netherlands rely mainly on gas-fired plants.

Another important feature of the electricity market is the level of concentration in the industry. This can be measured by two main indicators. First we consider the number of companies with a market share of at least 5% and secondly we consider the market share of the largest three producers. A third variable that we list in Table 1 measures the weight of the pool market on the total energy exchanged/consumed in a country. This liquidity multiple is very important because all Pool markets considered in our sample are non mandatory so that part of the total energy is exchanged through bilateral contracts at a price which is normally different from the SMP. The larger is the liquidity multiple for that market, the more representative is the SMP of the "price for electricity".

Table 1. Level of concentration and liquidity multiple of European exchanges

Country	Largest producer % share by capacity	Total % share of largest 3 producers	Liquidity
Austria (EXAA, 2002)	45	75	3
Scandinavia (Nord Pool, 1993)	15	40	42
France (Power Next, 2001)	85	95	3
Germany (EEX, 2002)	30	70	11
Italy (IPEX, 2004)	55	75	21
Netherlands (APX, 1999)	25	65	12
Spain (OMEL, 1998)	40	80	92

Source: Commission of the European Communities (2005)

The French market is characterized by the highest level of concentration with a dominant position of EDF. The French Pool market "Power Next" accounts for a very small quota of total energy consumed. This is also the case of Germany where only a small portion of energy is traded on EEX (11%). All the other markets listed in Table 1 appear to be fairly concentrated and to have a quite low liquidity ratio. There are two exceptions of a opposite sign: the Spanish exchange has a very large liquidity share and it has an oligopolistic structure. Nord Pool, on the contrary, appears to have a more competitive structure and a relatively high liquidity share.

From Table 1 we may conclude that across European countries the level of concentration in generation is still high and this creates the scope for market power and the ability to influence prices. Contrary to expectations, the strong position of incumbent operators has not been eroded in a significant way by investments in generation made by new entrants. Complex planning procedures and the scarcity of suitable sites have also been named as reasons why the building of new power plants does not take place. Uncertainties associated with the power exchanges have also been considered as entry barriers. Generation is a key issue for competition in the European electricity markets. The generators, due to the characteristics of the electricity market (the non-storability of electricity, the high inelasticity of demand, a very wide spectrum of costs of production and a price equal to the highest accepted offer (SMP) made in power exchanges), are able to influence prices through the use of generation capacity available to them, in particular by either withdrawing capacity (which may force recourse to more expensive sources of supply) or by imposing prices when their supply are indispensable to meet demand. In the first case, the withdrawal of capacity is profitable if the cost of not producing with some units is more than compensated by the increase in SMP. A large portfolio of low-cost plants facilitates this strategy. In the second case, it is possible to raise SMP even with a relatively small portfolio of plants depending on other offer constraints (e.g. the location of units). The behaviour of generators thus can impact significantly on the level of prices, even at a level of lower concentration than in other sectors.

Another relevant feature to be considered as an explanatory variable of price co-movements among European exchanges is the level of integration of local Pools. Indeed, there are interconnecting lines that allow for the cross-border exchange of electricity that is expected to flow from low price areas toward high price areas. The goal of integration of European electricity markets will be in fact achieved when the energy flows will determine a perfect convergence of Pool prices across European countries. The following Table 2 lists the existing interconnections among the exchanges considered and the status of the interconnection, namely the frequency with which congestion occurs. In fact, when congestion occurs in a particular hour, price convergence is not possible and the two local markets are separated.

Table 2. Capacity of interconnectors and frequency of congestion

Country		Capacity in winter (MW)			
Exp.	Imp.	2003–04	2004–05	2005–06	Congested
Powernext	EEX	2250	2550	2850	frequently
EEX	Powernext	4600	5600	5600	never
EEX	APX	3900	3800	3800	frequently
APX	EEX	2700	3000	3000	seldom
EEX	EXAA	1200	1600	1600	never
EXAA	EEX	1500	1400	1400	never
Nord Pool	EEX	1010	1150	1150	frequently
EEX	Nord Pool	920	1150	1150	occasionally

3. Time series analyses of electricity prices

The structural changes introduced in last decade in the organization of electricity markets have stimulated empirical studies of electricity price dynamics. The main elements emerging from some of these studies are summarized in Table 3.

TABLE 3. Empirical studies of electricity price dynamics.

	Atkins et al ('02)	Knittel et al. ('05)	Carnero et al. ('03)	Escribano et al. ('02)	Lucia et al. ('02)
Hourly (if not differently specified) electricity prices from	Alberta Power Pool	California 26 "zones"	APX, NordPool, EEX and Powernext	Average *daily* prices of NordPool, Argentina, Victoria (Australia), New Zealand, Spain	NordPool
Period analysed	01/01/98 to 30/09/2001	01/04/1998 to 30/08/2000	01/01/01 to 08/06/03 04/01/93 to 14/11/99 01/10/01 to 08/06/03 03/12/01 to 08/06/03	01/01/93 to 30/11/99 01/01/95 to 30/09/00 01/07/94 to 12/12/99 01/10/96 to 31/09/00 01/10/98 to 31/12/00	01/01/93 to 31/12/99
Raw data reveal:					
Seasonality	No specific test	a) Regular intra-day pattern b) Weekday/Weekend cycle c) Seasons	Strong weekly patterns of average daily prices in all markets	Only weekly and monthly considered	Strong seasonal pattern along the year with the exception of 1996
Volatility	High level of persistent and cluster volatility	Time varying and volatility clustering	Volatility clustering	Volatility periodicity considered with respect to the 4 seasons of the year	Strong volatility with seasonal differences
Mean reversion		Yes	Yes	Yes (slow for NordPool)	
Spikes and jumps		Jumps from every 20 to 33 hours (estimated). Extreme values are present Use jumps diffusion models and exponential GARCH	Yes	Important price spikes and jumps detected GARCH process with jumps	Yes with extreme values
Time series Model					
Method	4 versions of conditional ML model with and without mean reversion and jump diffusion	Conditional ML (Various versions starting from a Ohrnstein-Uhlenbeck process)	Various regressions ARIMA structure and PAR models	ML on 6 nested models GARCH-Poisson-Gaussian outperforms constant volatility and pure jump models (except Spain)	Non linear LS (Various versions starting from a Ohrnstein-Uhlenbeck process)
Long memory	Yes	High	NordPool shows specific features		Strong

	Park et al. ('06)	Bosco et al. ('06)	Mount et al. ('06)
Hourly (if not differently specified) electricity prices from	Daily peak prices 11 U.S. spot markets	Italian Pool Market IPEX	Daily prices for PJM
Period analysed	26/02/98 20/12/2002	01/04/2004 15/01/2005	01/05/1999 31/05/2000
Raw data reveal:			
Seasonality	No specific test	Weekday/Weekend cycle Vacation Seasons	
Volatility	High level of volatility (all 11 series)	High	High (especially in summer)
Mean reversion	Yes	Yes (speed similar to Spain as found by Escribano et al.)	
Spikes and jumps		Important price spikes and jumps detected	High spikes (capacity dependent)
Time series Model			
Method	Multivariate VAR and Causal Flows Analysis	EGARCH (1,1)	Recursive Log-Likelihood Function of a regime-switching model with transition probabilities functions of the load and reserve margins
Long memory	In contemporaneous analysis markets are separated from each other but at longer time frames (30 days) these separations disappear even though electricity transmission between the regions is limited	Not strong and different for working days and weekends.	

As it is apparent from Table 3, the initial objective of these analyses was to characterize and explain the high degree of autocorrelation and seasonality of power prices and, in some cases, to address some salient issues useful to the valuation and hedging of power-based financial contracts. A common trait of this literature is the adoption of a sort of two-step procedure. A preliminary data analysis is initially conducted in order to gauge from data inspection the main characteristics of the dynamics of the electricity prices. On the basis of this examination it is almost invariably recognized that the models used in the second step for the time series analysis of spot prices have to integrate seasonality and reflect phenomena such as mean reversion, high price-dependent volatility and leptokurtosis. For example, Lucia et al. (2002) present a model which should permit the definition of analytical formulae for derivative pricing. They employ seasonal dummies and sinusoidal functions to deal with seasonality plus an AR(1) autocorrelation structure.

In his paper Bahnot (2000), using U.S. wholesale transaction prices recorded from 1 January 1995 to 1 June 1998, discovered that the seasonal means for peak and off-peak prices exhibit significant variation across the 12 months and across the delivery points. He also shows that the price behavior changes with each regional market, so that a firm that seeks to value or hedge power-based contracts must use instruments tailored for the region in which it operates. The issue of seasonality was considered also in other papers. Real-time balancing and dependency on cyclical demand impose several different seasonal pattern to electricity prices (within day, week, year) almost everywhere. Deidersen and Trück (2002) study price series for Germany, New Zealand and Spain and report strong intra-day pattern and peak during midday. Moreover, monthly mean prices are higher during daytime and weekly seasonal patterns show the presence of weekend effects. Also Knittel et al. (2005), using a model in which the mean was assumed to be time dependent, found that Californian electricity prices show intra-day seasonality and "summer" (rather than winter) effect. Annual seasonality was also found with winter prices always higher than prices recorded in other seasons. On the contrary, mixed evidence was obtained by Wilkinson et al. (2002) who use Australian data and conduct a non-parametric test of seasonality (peak and off-peak prices) and of log-normality. In their estimations the null hypothesis of equal day effects was rejected for some sub-sample periods and not rejected for some other periods.

Storage and transmission problems and the need for markets to be balanced in real time are responsible of an unusually high volatility of electricity prices accompanied by the presence of spikes and jumps. This stimulated specific research. All the above reported empirical evidence coincides in stressing that there is a strong correlation between the standard deviation and the mean price making the volatility dependent on the price level. This means that price series exhibit some volatility clustering making models for conditional heteroskedasticity opportune. When demand approaches and exceeds the limits of the system generation capacity, prices are high and more volatile. Escribano et al. (2002) use average daily prices of several markets and propose a general and flexible model that allows for deterministic seasonality, mean reversion, jumps and conditional heteroskedasticity. They use six nested versions of their model to analyze price behavior in the above markets. Results indicate that AR(1) and GARCH (1,1) with jumps perform better than other versions. Koopman et al. (2006) use European data. They argue that the heteroskedasticity of prices can be correctly represented only when the conditional mean of the time series is modeled by means of periodic autoregressive processes. Accordingly, they proceed to model the seasonalities by means of sinusoids and weekday dummies. PAR(1) models seem to fit best their data. They find evidence of mean reversion in the stochastic part of the model and long memory in the Nord-Pool prices. As for spikes and jumps, they are attributed to sudden and strong increase in demand when supply is at the limit of generation capacity or to an unexpected break down of large enough assets. Depending on demand and supply conditions they can also be negative. According to Deidersen and Trück (2002) they are less frequent in market with high level of hydropower generation. Still, spikes are quite pervasive and it is the presence of spikes what makes the forecasting properties of the models used in the literature rather poor. These extreme values can be modeled in discrete time by using stochastic process with leptokurtic marginal distributions or in continuous time by introducing jumps in a Wiener process (see for example Atkins et al. 2002). Byström (2005) models extreme price changes in the Nord-Pool and estimates tail quantiles by filtering the return series and then applying an extreme value theory model to the residuals. Like in other studies, the performance of the estimates improves when the model takes into account explicitly the time-of-the-year seasonality of the data. An alternative procedure to predict price spikes is followed by Mount et al. (2006) who proposed a recursive Log-Likelihood Function of a regime-switching model with transition probabilities functions of the load and reserve margins thereby introducing exogenous variables in the analysis of price series.

A specific characteristic of price series was discovered to be mean reversion. By mean reversion we mean the absence of stochastic trends or martingale-like behavior of prices. Electricity prices do not behave as martingales, and the non-deterministic part of the data generating process does not seem to contain unit roots (e.g. no random walk like behavior). When hourly prices go up then they have to move downwards again in a relatively short time. It is thought that they oscillate around some "equilibrium" mean (possibly deterministically time varying). This makes a crucial difference with financial markets. The speed of the reversion is quite informative also in regulatory terms because it displays the time needed by the supply side of the market to react to unanticipated events or the time necessary for the event to be over. The mean reverting nature of electricity prices is generally explained by market fundamentals. Commonly held opinion is that only mean reverting models with jumps allow for brief price spikes (see below) observed in price data and that only the short term mean reversion is the result of seasonal patterns. In the long run electricity prices may revert to some mean. Mean reversion and seasonality are integrated in a model proposed by Lucia et al. (2002) where the price is decomposed into a deterministic and a stochastic component the latter following a Ohrnstein-Uhlenbeck mean reverting process with zero mean so that price revert to the deterministic function. Using Italian daily data, Bosco et al. (2006) estimate periodic time series models with exponential GARCH disturbance and leptokurtic distributions and compare their performance with more classical ARMA-GARCH models. They find that much of the variability in the price series is explained by the interactions between deterministic multiple seasonalities and that periodic AR-GARCH models mimic well the feature of the stochastic part of the price process.

All the above considerations refer to markets working in isolation. Yet, when there are neighboring markets operating in national (or super-national, such as the European market) systems, they may be characterized by strong interdependencies because of limited storability and transmission (Lucia et al., 2002). In fact volatility and interdependency might result from highly interconnected transmission systems and transmission congestion. DeVany et al. (1999a,b) study electricity price behavior for western U.S. markets and find that all of off-peak price series and most of peak price series are pair-wise cointegrated and, contrary to Bahnot (2000), that prices show relatively rapid convergence with respect to external shocks. Park et al. (2006) examine relationships among 11 U.S. spot markets for the period February 1998 to December 2002 using peak working days firm prices (no week-end data). They find that the relationships among the markets vary by time frame. In contemporaneous analysis markets are separated from each other but at longer time frames (30 days) these separations disappear even though electricity transmission between the regions is limited. This suggests that the relationships among markets are not only a function of physical assets (e.g. transmission lines) but also a function of market rules and institutional arrangements as well as of factors (e.g. oil price) affecting in a similar or dissimilar way the markets or factors that are peculiar to each market (e.g. generation technology). Once again exogenous variables were explicitly introduced. As for Europe, Bower (2002), Boisselau (2004), Armostrong et al. (2005) and Zachmann (2005) compare electricity prices at various European power exchanges. The first two papers study the properties of prices series in some markets to find evidence of some converging trends in average prices. Armstrong et al. (2005) analyze the time pattern of differentials in average prices in France, Germany, the Netherlands and Spain from 2002 to 2004. They conclude that the hypothesis of some convergence of average yearly prices was consistent with the data. Zachmann (2005) starts from the idea that cross-border trade among national markets should drive prices to converge especially for those markets having larger cross-border trade. Using hourly cross-border capacity auction results at the Dutch-German and Danish-German border for the years 2002 to 2004 as well as internal spot prices, he estimates a time-varying coefficient model of the difference between domestic and import prices to be used to construct a "proximity index" indicating the extent of the deviation of the observed prices from a common unique price. The behavior over time of this index indicates the speed of convergence of national markets towards an integrated market obeying the "law of one price". His outcomes indicate that arbitrage opportunities seem to be reduced but mainly because of progress made in the management of cross-border capacity. Interdependencies are not considered and spikes and jumps, and their repercussion from one market to the next, are not easily interpreted.

4. Empirical analysis

4.1. **Unit roots and cointegration in European electricity prices.** Most of the authors who analysed electricity prices in competitive markets have found that mean reversion was a distinguishing feature of these time series (de Jong and Huisman 2002, Deisden and Trück 2002, Escribano et al. 2002, Huisman and Mahieu 2003, Koopman et al 2006, Knittel and Roberts 2005, Lucia and Schwartz 2002, Park et al. 2006). Bosco, Parisio and Pelagatti (2006), used a mean-reverting model for modelling Italian electricity prices, but stated that, while mean reversion may be a sensible approximation when a relatively short period of time is considered (other features dominate the variance), it is hard to believe that electricity process are not related to oil prices, which typically exhibit unit root behaviours. In fact, a great part of the European electricity is produced by thermoelectric generators, and even if this may be not true for some countries (France, Austria and Scandinavia), many neighbouring countries are relatively well connected, reducing, through arbitrage, the spread between prices. Although thermoelectric plants are usually alimented by natural gas,

"there is intense competition between natural gas and other fuels on the energy market. As the competitive price level is subject to constant fluctuations, supply contracts contain price adjustment clauses that maintain a balance between the gas price and the price of competing energies for the entire duration of the contract. In most cases, price adjustment clauses are referred to fuel oil, reflecting the competitive situation. Such fuel oil clauses peg the development of gas prices to the development of fuel oil prices."[2]

Villar and Joutz (2006) find evidence of cointegration between natural gas (Henry Hub) and crude oil (West Texas Intermediate) prices in US, even though the deviation from the equilibrium relationship is rather persistent.

So, if in the long run, European electricity prices tend to have a constant mean ratio with the prices of gas, and this tends to have a stable ratio with oil prices, than the logarithm of electricity prices of many European countries and the logarithm of oil prices should be

[2]From the Verbundnetz Gas AG web site: http://www.vng.de/content/englisch/Natural_Gas_Market/Market_Data/Gas_prices/index.html

cointegrated with one common trend (null cointegration space rank equal to one).

In some of the cited works on electricity prices, unit root tests were carried out, but their results systematically rejected the unit root hypothesis. Their evidence seems to contrast our conjectures about electricity prices behaviour, but there are good reasons for believing that their results were not accurate.

(i) First of all, the sample periods considered included times of relatively moderate oil price movements, and the high volatility of the other components (seasonality, noise, outliers) turns the problem of finding a unit root similar to the one of extracting a signal buried into a great amount of noise. More formally, the random walk signal $\mu_t = \mu_{t-1} + \eta_t$, with η_t white noise process with variance $\alpha\sigma_\varepsilon^2$, is observed with noise, $y_t = \mu_t + \varepsilon_t$, with ε_t white noise process with variance σ_ε^2. It is easy to see by taking first differences, that y_t has the ARIMA(0,1,1) representation (Harvey 1989, p.68 for example)

$$(1 - B)\, y_t = (1 + \theta)\, \xi_t \tag{1}$$

with

$$\theta = -\frac{\alpha + 2 - \sqrt{\alpha^2 + 4\alpha}}{2} \tag{2}$$

and ξ_t white noise process with variance $-\sigma_\varepsilon^2/\theta$. When the noise variance is high compared to the signal variance, α is close to zero and the MA coefficient θ tends to one, making the MA operator on the right hand side of (1) almost cancel out with the difference operator on the left hand side. The small sample paths generated by process (1) in such a situation are not distinguishable from white noise.

(ii) Secondly, it is well documented (Franses and Haldrup 1994) that the augmented Dickey-Fuller (ADF) test[3] and Johansen's cointegration tests perform poorly when additive outliers and temporary changes are present, and the test results are heavily biased towards rejection of the unit root hypothesis.

(iii) Thirdly, electricity prices time series show very rich dynamics, periodicities and multiple seasonalities (Koopman et al. 2006, Bosco et al. 2006), high volatility and conditional heteroskedasticity (Escribano et al. 2002, Byström 2005), jumps and regime switches (Fabra and Toro 2005, Huisman and Mahieu 2003). Nord Pool prices seems to be also long memory (Koopman et al. 2006, Haldrup and Nielsen 2004).

Only Escribano et al. (2002) use unit root tests able to cope with points (ii) and (iii), but problem (i) holds also in their study.

[3]The ADF test is the one used in most of the cited studies (Lucia and Schwartz 2002, Park et al. 2006, Haldrup and Nielsen 2004), only Knittel and Roberts (2005) use the Phillips-Perron test.

Suppose now that a stochastic I(1) trend μ_t is present in N time series although buried in (possibly coloured) noise:

$$(3) \qquad y_{i,t} = \alpha_i + \beta_i \mu_t + \varepsilon_{i,t}, \quad t = 1, \ldots, T, \quad i = 1, \ldots, N,$$

with $\varepsilon_{i,t}$ I(0) noises uncorrelated or weakly correlated with each other[4]. By taking the principal components (PC) we expect that if the trend μ_t is the main source of correlation among the series, the first principal component should contain a partially de-noised version of μ_t. Asymptotically, the first principal component converges to (a rescaled version of) μ_t, since its $O(T)$ variance dominates the $O(1)$ variances of the I(0) noises, and the common trend becomes the only source of correlation among the series. Since (2) contain only a common trend and the last $N-1$ principal components are orthogonal to the first, they (asymptotically) span the cointegration space, whose null space is spanned by μ_t.

The use of principal components methods to cope with cointegration is not new in literature: tests and estimates based on PC may be found in Stock and Watson (1988), Harris (1997), Snell (1999) and, more recently, Chigira (2006). In particular, in finite samples Chigira's (2006) test seems to perform better than Johansen's, even under the assumptions required by Johansen's procedure, in spite of the weaker assumptions needed by Chigira's method.

In order to test our conjecture, we decided to apply PC and Chigira's cointegration test on the (logarithm of) electricity prices observed in some of the most important exchanges in Europe: EEX (Germany), Powernext (France), APX (Netherlands), EXAA (Austria). We kept Nord Pool (Scandinavia) out of the analysis since the stochastic properties of its prices seem different with respect to the other markets (cf. Koopman et al. 2006 and Figure 2). This empirical consideration is supported by the fact that most of the electricity exchanged in this market is generated by hydro-plants, and its geographical position makes connections with other European countries harder. In the first analysis we did not consider Omel (Spain) and IPEX (Italy), because of their relatively short history (data are available since 2004).

Because of points (ii) and (iii) above, we decided to work on weekly medians of the original hourly time series. The advantages of this non linear transformation are twofold: it filters out many outliers and makes cointegration tests more robust (Arranz and Escibano 2004), and it cleans from the nuisance of interacting within-day and within-week seasonalities (cf. Bosco et al. 2006). In principle, the analysis carried

[4]By weakly correlated we mean that $\bar{\varepsilon}_{N,t} = N^{-1} \sum_{i=1}^{N} \varepsilon_{i,t} \xrightarrow{p} 0$ as N grows and that the variance of $\bar{\varepsilon}_{N,t}$ is smaller than the variance of any $\varepsilon_{i,t}$ for the dimension of our sample. This is not an unrealistic requirement in our framework: it is equivalent to ask that factors other than gas/oil prices tend to become less important the more two countries are far away from each other.

out on weekly medians could be extended to any percentile or quantile, but in this study we worked only on medians. The medians were taken on a span starting from the first hour of Mondays to the last hour of Sundays and sample ranges from the 25^{th} March 2002 (Monday) to the 4^{th} June 2006 (Sunday).

In Figure 2 the weekly medians are depicted: the de-noising effect of the medians make the co-movements very clear. Even without a formal test, the visual inspection suggests the presence of a common stochastic trend.

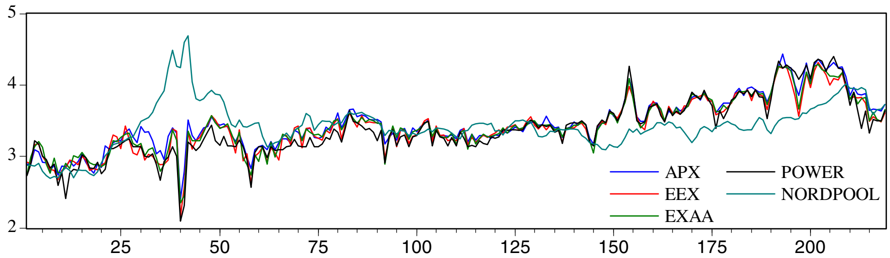

FIGURE 2. Empirical studies of electricity price dynamics

Table 4 reports the main results of PC analysis performed on the correlation matrix. The first component takes account of almost 98% of the total variance and the corresponding eigenvector puts weights that are almost identical for each time series.

TABLE 4. Eigen-structure of the correlation matrix of APX, EEX, EXA, Powernext.

	Comp 1	Comp 2	Comp 3	Comp 4
Eigenvalue	3.910006	0.045251	0.031012	0.013731
Variance Prop.	0.977501	0.011313	0.007753	0.003433
Cumulative Prop.	0.977501	0.988814	0.996567	1.000000
Eigenvectors:				
Variable	Vector 1	Vector 2	Vector 3	Vector 4
APX	0.499719	-0.199870	-0.834597	0.117395
EEX	0.500659	-0.421718	0.482612	0.581876
EXAA	0.502447	-0.226842	0.242895	-0.798180
POWER	0.497161	0.854838	0.107405	0.102698

If our conjecture is true the first component should be an I(1) process, while the other ones should be I(0), making the corresponding eigenvectors consistent estimates of cointegration vectors (cf. Harris 1997, Snell 1999 and Chigira 2006). Figure 3 suggests that this may be the case.

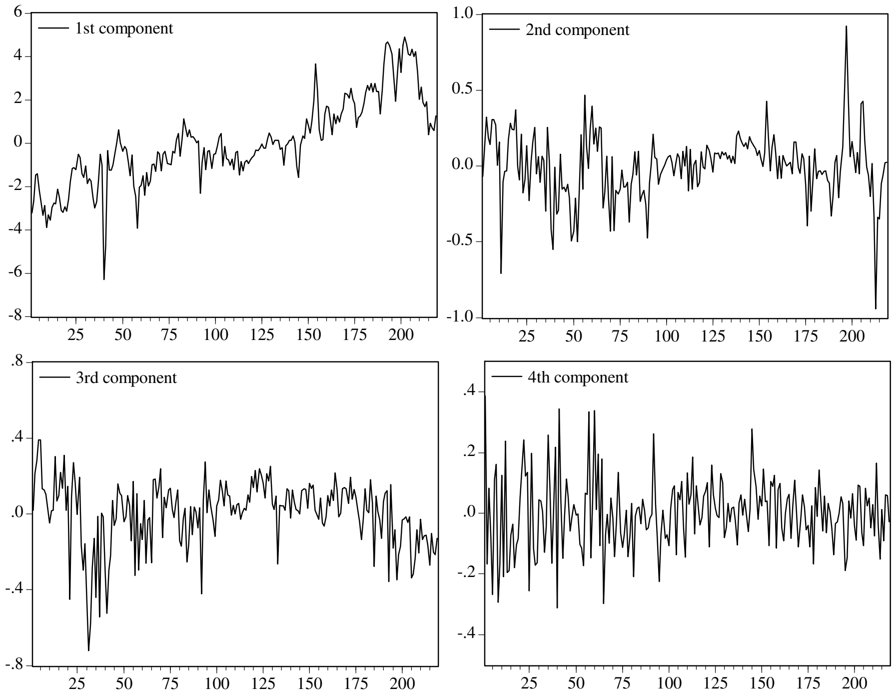

FIGURE 3. Principal components of APX, EEX, EXAA, Powernext.

Following Chigira (2006) we apply the I(1) tests of Phillips and Perron (1988) and Breitung (2002) and the KPSS I(0) test of Kwiatkowski et al. (1992) to the principal components. Chigira (2006) proposes a sequential procedure for testing for the cointagration rank:

(1) set $i = 1$,
(2) test the i-th PC for a unit root,
(3) if there is evidence against the unit root, set the cointegration rank to $N - i + 1$ and stop, else increment i by one and go to line 2.

The algorithm should be reversed if an I(0) test is used:

(1) set $i = N$,
(2) test the i-th PC for the absence of unit roots,
(3) if there is evidence for unit roots, set the cointegration rank to $i - 1$ and stop, else decrement i by one and go to line 2.

The advantage of using Phillips-Perron and Breitung tests in the first procedure, when compared to the ADF test, is that they work under much milder assumptions, allowing a wide class of weakly dependent and heterogeneously distributed time series.

The results of the testing procedures applied to our data are summarized in Table 5. All tests support the hypothesis of three cointegrating relations, in fact only the first PC seems to be I(1). For the I(1) test-based procedure (second and third column), the process stops at the second step, but we report all the test-statistics for completeness. Johansen's tests (with unrestricted constant, not reported) applied to the original series support stationarity of the system.

TABLE 5. Unit root and stationarity tests on the principal components.

	Phillips-Perron	Breitung	KPSS
1^{st} PC	-2.812	0.0709	3.5039*
2^{nd} PC	-9.032*	0.0017*	0.1548
3^{rd} PC	-9.360*	0.0033*	0.2661
4^{th} PC	-16.542*	0.0005*	0.1376

The tests have been performed using Newey-West variance estimates with truncation lag 4. The 5% nominal critical value for the PP test is -2.875, for Breitung's test is 0.0100, for the KPSS test is 0.463.

Figure 4 depicts the first PC together with the weekly median of the Brent log-price in Euro (standardized data). The two time series clearly show a common tendency. The somewhat anomalous behaviour of the first PC in the latest part of the sample is the product of the Russia-Ukraine gas crisis begun in the cold winter 2005/2006[5].

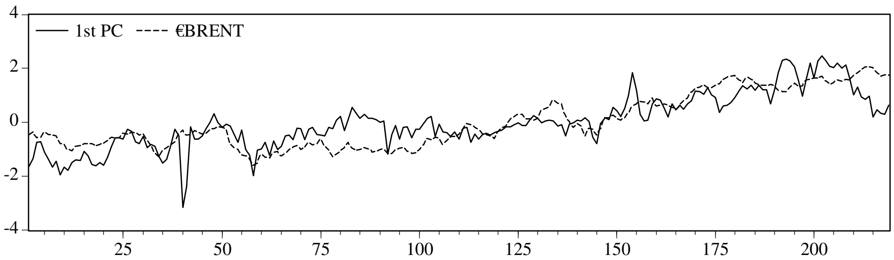

FIGURE 4. First principal component with standardized weekly median log-prices of a barrel of Brent in Euro.

We repeated the analysis including the Brent price in Euro. The eigen-structure of the correlation matrix may be read from Table 6.

The cointegration tests are summarized in Table 7. The PP and KPSS tests support the presence of a single common trend (four independent cointegration vectors), while Breitung's test suggests the presence of two common trends (three independent cointegration vectors).

[5]For an extensive account of this crisis refer to http://en.wikipedia.org/wiki/Russia-Ukraine_gas_dispute.

Table 6. Eigen-structure of the correlation matrix of BRENT, APX, EEX, EXA, Powernext.

	Comp 1	Comp 2	Comp 3	Comp 4	Comp 5
Eigenvalue	4.568222	0.342267	0.045249	0.030531	0.013731
Variance Prop.	0.913644	0.068453	0.009050	0.006106	0.002746
Cumulative Prop.	0.913644	0.982098	0.991148	0.997254	1.000000
Eigenvectors:					
Variable	Vector 1	Vector 2	Vector 3	Vector 4	Vector 5
BRENT	0.394638	-0.918115	-0.002453	0.036327	-4.15E-05
APX	0.460105	0.165049	-0.201286	-0.840698	-0.117360
EEX	0.459435	0.217462	-0.420127	0.475956	-0.581884
EXAA	0.461371	0.208219	-0.225799	0.236019	0.798180
POWER	0.456751	0.197936	0.855562	0.098325	-0.102693

At a 10% level, also Breitung's test would support the one-common-trend hypothesis[6]. For completeness we carried out also Johansen's test (not reported) and, this time, the conclusions agree.

Table 7. Unit root and stationarity tests on the principal components

	Phillips-Perron	Breitung	KPSS
1^{st} PC	-2.428	0.0770	1.0582*
2^{nd} PC	-4.764*	0.0137	0.3024
3^{rd} PC	-9.271*	0.0017*	0.2661
4^{th} PC	-11.345*	0.0031*	0.1150
5^{th} PC	-16.412*	0.0005*	0.1415

The tests have been performed using Newey-West variance estimates with truncation lag 19. The 5% nominal critical value for the PP test is -2.875, for Breitung's test is 0.0100, for the KPSS test is 0.463.

4.2. **Dynamic multivariate analysis.** Building on the results of the cointegration analysis we estimated a vector error correction model (VECM). In order to determine the number of lags of the differenced variables to be included in the model, we estimated unrestricted VARs and looked at the different information criteria. AIC suggested two lags, while SC and HQ recommended just one[7]. For parsimony and

[6]For completeness we carried out ADF tests with lags chosen according to the Schwarz information criterion and the conclusions were the same as the ones based on the PP test. The ADF test for the second PC was very close to the 5% critical value and extremely sensitive to the number of lags.

[7]AIC, SC and HQ stand for Akaike, Schwarz and Hannan-Quinn information criteria, respectively.

for the better small sample properties of SC and HQ, we decided to allow for only one lag. The modulus of the greatest root of the companion matrix turned out to be almost equal to one (0.995) with the second greatest root being 0.795, again supporting the hypothesis of an integrated system with just one common trend.

TABLE 8. Cointegration vectors (matrix β).

Coint. Eq:	CointEq1	CointEq2	CointEq3	CointEq4
BRENT	1.04	1.00	1.00	1.13
(std.err.)	(0.164)	(0.150)	(0.153)	(0.178)
APX	-1.00	0.00	0.00	0.00
EEX	0.00	-1.00	0.00	0.00
EXAA	0.00	0.00	-1.00	0.00
POWER	0.00	0.00	0.00	-1.00
Constant	-0.15	-0.07	-0.07	-0.54

By estimating the cointegrated system we imposed just-identifying restrictions to facilitate the interpretation of the results. The estimated cointegration vectors are shown in Table 8. Since data are in logarithm, the first row of the matrix β may be interpreted as the long-run elasticity of the prices of, respectively, APX, EEX, AXAA, Powernext with respect of the price of Brent (in Euro)[8]. Using De Vany and Walls's (1999) terminology, if all the coefficients of the first row of the matrix β were ones, then we would have *strong integration* among electricity markets and between the electricity markets and the oil markets. Strong integration is equivalent to the absence of long run of arbitrage opportunities when "trading" on median electricity and oil prices. We imposed the strong integration restrictions and the likelihood ratio (LR) test could not refuse the null hypothesis at any usual level of significance ($p = 0.16$).

We estimated the ECM again imposing strong integration to compare the speed of adjustments of the electricity prices to a shock in the oil prices. The generalized impulse response functions are depicted in Figure 5.

The adjustments are rather slow for all time series: half life is circa four weeks. APX and Powernext tend to react a bit more gradually.

In order to check for the robustness of the previous results, we estimated a system of four regressions, where each electricity price time series (in log) was regressed on a constant and the Euro-Brent prices time series:

$$\log \mathbf{y}_t = \alpha + \beta \log x_t + \varepsilon_t \tag{4}$$

[8]This is true if we suppose that oil prices influence electricity prices but not vice versa.

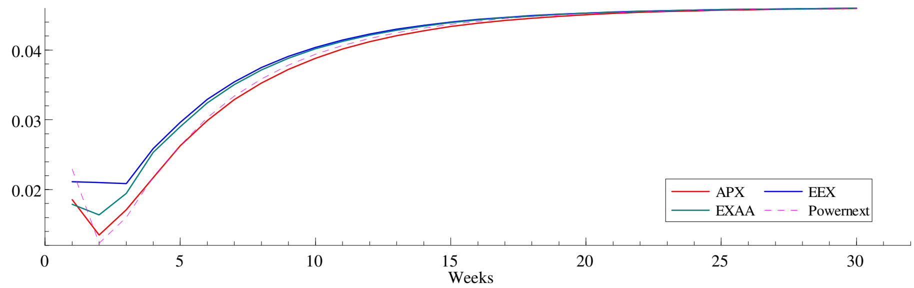

FIGURE 5. Generalized impulse response functions of the electricity prices to a positive shock in oil prices.

with $\mathbf{y}_t$ vector of weekly median electricity prices, x_t Euro-Brent prices time series, α and β vector of regression coefficients and ε_t vector I(0) process. The system was estimated using the generalized method of moments (GMM) with Newey-West HAC covariance matrix estimator, and the strong integration hypothesis was tested by means of a Wald type statistic. Again, the strong integration hypothesis could not be rejected at any usual level of significance ($p = 0.13$).

An even stronger form of market integration holds if: i) strong integration holds and ii) all the long run ratios of electricity prices of different markets equal one. De Vany and Walls (1999) call this *perfect integration* of the electricity markets. This assumption holds if all the elements of α in system (4) are equal. The hypothesis of perfect integration was tested using, again, a Wald type statistic, but the null was strongly rejected. Indeed, the long run energy price level tends to be higher in the APX market, than in EXAA, than in EEX, than in Powernext (this being the actual ranking).

5. Concluding comments

This paper analyses for the first time the interdependency existing in the dynamics of prices formed in four major European electricity markets (Germany, France, Austria, Netherlands). We conducted a multivariate dynamic analysis of weekly median prices and our results question the most commonly reported finding of mean reversion and, implicitly, of no integration of European prices. On the contrary, our tests indicated the presence of strong integration (but not perfect integration) among the four markets and the existence of a common trend among electricity prices. This means that there are no long-run arbitrage opportunities We found that this common trend is in turn cointegrated with the oil price. The latter result appears to be relevant also in the context of the discussion of efficient hedging instruments to be used by medium-long term investors.

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