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Empirical Evidence for Inefficiencies in European Electricity Markets – Market Power and Barriers to Cross-Border Trade?

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Preface

Few industries have undergone so many significant changes to general framework conditions in such a short period as Europe’s electricity sector at the dawn of the new millennium: market opening, third-party access, renewable support schemes, emissions trading, incentive regulation, and many more measures were all introduced within one decade. Despite the many setbacks and delays, the European wholesale electricity markets moved irresistibly from a national monopolistic to an international oligopolistic structure. The corresponding facts and figures are impressive: the share of electricity traded at the European Energy Exchange, Leipzig (EEX) spot market rose from under 1% in 2000 to around 18% in 2007; more transmission links are congested due to increasing international trade; a few “national” blackouts have disseminated throughout Europe; and small German municipalities have begun trading with generators in Spain.

It is exciting to undertake research at this time, but there is always the danger that one’s findings may become obsolete before publication, or disproved by newly available data. Nonetheless, the attractions for researchers are substantial: the opportunity to be the first on a particular subject; the vibrant collegiality of the international research community; the interest of the general public and newly appointed regulators; and finally, the privilege of attending conferences in the most beautiful places throughout Europe. All are rewards enough for the hours spent preparing sometimes futile data sets, or reworking hypotheses.

I am especially appreciative of my supervisor, Christian von Hirschhausen, and my colleagues Franziska Holz and Anne Neumann, who provided the necessary confidence, and made themselves available when questions arose. Christian von Hirschhausen introduced me to the scientific community – my first presentation before a large, international audience occurred only 5 months after I began work in this field – and later challenged me with projects whose findings I incorporated in this dissertation.

Further, I thank the examiners of this thesis. Derek Bunn made possible a three-month research visit to the London Business School that proved especially productive. Bringing me together with energy economics PhD students and regularly creating time for conversation

Derek Bunn provided important assistance. With Jean-Michel Glachant I associate a set of stimulating discussions, particularly in the frame of the French-German PhD-seminars that his chair, together with Christian von Hirschhausen, alternately hosts in Paris and Berlin. I also acknowledge Bernhard Schipp, who kindly agreed to support my dissertation.

Berlin, May 2009 Georg Zachmann

Abstract

This dissertation applies a variety of quantitative methods to European electricity market data to enable us to detect, understand, and eventually mitigate market imperfections. The empirical data indicate that market power and barriers to cross-border trade partially explain today's market failures. Briefly, the five key findings of this dissertation are:

First, we observe a decoupling between German electricity prices and fuel cost, even though British electricity prices are largely explained by short-run cost factors.

Second, we demonstrate that rising prices of European Union emission allowances (EUA) have a greater impact on German wholesale electricity prices than falling EUA prices.

Third, we reject the assumption of full integration of European wholesale electricity markets in 2002-2006; for several pairs of countries, the weaker hypothesis of (bilateral) convergence is accepted (i.e. efforts to develop a single European market for electricity have been only partially successful).

Fourth, we observe that daily auction prices of scarce cross-border transmission capacities are insufficient to explain the persistence of international price differentials. Empirically, our findings confirm the insufficiency of explicit capacity auctions as stated in the theoretical literature.

Fifth, we identify inefficiencies in the market behavior for the interconnector linking France and the United Kingdom (UK), for which several explanations, including market power, may be plausible.

The thesis is structured in six chapters. Following this summary, Chapter I presents an overview of the issues concerning European electricity wholesale markets. The four core chapters, II-V, provide empirical indication for inefficiencies in European wholesale electricity markets. Finally, Chapter VI summarizes the contributions of this dissertation and offers suggestions for further research.

I Introduction

I.1 Brief Introduction to European Wholesale Electricity Markets

Electricity markets differ from other commodity markets in many aspects. Demand for electricity is inelastic in the short term, storing it is impossible, components of the value chain exhibit characteristics of natural monopolies, and reliable supply has great macroeconomic importance. In the latter half of the twentieth century, these features gave rise to uncompetitive market structures in many countries. In Europe and the United States (US), privately or public owned vertically integrated regional monopolies predominated. However, during the revival of economic liberalism in the 1980s ("Thatcherism" and "Reaganism"), vertical integration began to be challenged.[1] Why this paradigm shift to privatizing many state-owned industries (not only in the electricity sector) occurred in precisely this decade and arose first in the Anglo-Saxon world is only partially understood today. Cockett (1994) argues that the intellectual climate itself changed during the 1970s and 1980s. A survey of the political economy literature reveals that strongly conservative governments, like the Thatcher and Reagan administrations, are more likely to promote and realize privatization projects.[2] Others argue that increasing fiscal deficits, growing state shares, booming stock markets, diminishing performance of state-owned enterprises,[3] and the general failure of Keynesian policy following the oil price shocks of the 1970s influenced the transformation "from state to market".[4]

Following the United States and United Kingdom's (UK) experiences, the liberalization of European electricity markets began to gain momentum during the 1990s, with the backing of the UK administration and the European Commission. In 1991, the European Community's (EC) Energy Commissioner, Antonio Cardoso e Cunha, proposed a directive liberalizing gas and electricity markets. Five years later, after fierce battles between the electricity industry and liberalization-skeptical countries on one side and pro-liberalization countries and the Commission of the EC on the other, the electricity market Directive 1996/92/EC was enacted. In this context, Article 90 [now 86] of the European Economic Community treaty equipped

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[1] Kahn (1995) describes the Public Utilities Regulatory Policies Act (PURPA) of 1978, which allows for independent generators, as the watershed of US electricity market policy. He notes that by 1992, independent power producers already accounted for 10.7% of US electricity sales.

[2] See Boix (1997), Bortolotti et al. (2003), and Bortolotti and Siniscalco (2004).

[3] Fabrizio et al. (2004) empirically demonstrate that the efficiency of restructured power plants in the US indeed increases.

[4] See Heffernan (2002).

the Commission with the necessary unilateral power to break up national monopolies; it also functioned as a lever to enforce the collaboration of reluctant member states in drafting the reform package. Despite its departure from requiring full liberalization (continued existence of the "single buyer model"; "public service obligations"; high thresholds for market opening), the directive laid the groundwork for restructuring Europe's markets.[5] Yet the ultimate goal of a single, vibrant electricity market was still far off.[6]

The next significant step was taken in 2003 when the European Union (EU) issued Directive 2003/54/EC and Regulation 1228/2003. Both obliged member states to undertake further substantial reform efforts, requiring that markets be opened; obstacles to cross-border trade be reduced; and that non-discriminatory third-party access to the network be guaranteed. To date, implementation (via the enactment of national laws) still varies. Even a cursory read of the reports benchmarking the reforms such as EC (2005, 2006), and OXERA (2005) reveals many remaining differences.

The diversity of national approaches to electricity market reform can be explained by country-specific characteristics. Important determinants include political will; political ability; strength of interest groups; and path dependency. Therefore, the failure to achieve certain targets – diagnosed in the EC sector inquiry, for example – will have different reasons. In Europe, some administrations were reluctant to expose their "strategic industry" to market conditions. The complexity of reforming an age-old industry structure continues to pose serious challenges for other administrations.[7] In some cases, governments gave priority to competing environmental, economic or social policy targets.

Apart from privatization, unbundling, and retail competition; creating a *common* competitive electricity wholesale market was a desired goal of Europe's electricity market policy, for which workable *national* wholesale markets are the cornerstone (see Section I.3). Thus, consumers were allowed to choose their supplier. In general, this *market opening* was implemented in steps; most countries first permitted only the largest consumers to "shop around." Subsequently, bilateral trading and brokered deals were introduced. This so-called over-the-counter trade (OTC) provided custom-tailored products at low, fixed-transaction

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[5] Andersen and Sitter (2007).

[6] A single market refers to the expectation of a competitive market and the efficient allocation of generation and transmission resources, at least at a regional level, if not at the level of the new EU 25.

[7] For example, we observe that the arduous process of reform requires specialized education and training for administrations and regulators and these were disseminated only gradually.

costs. But as variable transaction and search costs remained high and market non-transparency incurred additional expense, traders and buyers demanded another marketplace that offered standardized products. Today, most of the older and some of the new EU member states have established power exchanges, nearly all of which feature a spot market (electricity trading for each hour of the day ahead). The prices deduced at the power exchanges are usually publicly available. Because they serve as a national reference price, most countries regard spot prices as the key indicators for the wholesale price level.[8]

With the emergence of electricity spot markets, the statistical behavior of the prices attracted the attention of speculators, arbitrageurs and risk managers, not least because future and option contracts are usually settled at the spot price. This opened a new field of study for financial mathematics, and it soon became obvious that electricity prices behave very differently from prices for physical commodities. Important findings include the observations that prices mostly contain no unit root (Lucia and Schwartz (2001), Worthington et al. (2005)); exhibit mean reverting behavior (Cartea and Figueroa (2005)); feature strong seasonalities; high volatility; fat tails; and long memory behavior (Haldrup and Nielsen (2004)). Sophisticated stochastic models for electricity prices were developed based on the observed characteristics.[9] As weather, fuel prices, emission allowance prices, available generation capacities, imports, transmission congestion, market structure and the national fuel mix are key explanatory variables for price behavior; electricity price models are often only suitable for a specific power exchange. Electricity prices in the Scandinavian countries for example contain a unit root unlike those in the UK (the high share of hydropower makes electricity indirectly storable in the Nordic countries, which is not the case in the thermally dominated UK market). Subsection I.3 will discuss the national specificity of electricity price behavior in relation to cross-border electricity trade.

Market implementation did not proceed without difficulties. The low liquidity, unexplained price jumps, persistent international price differences, repeated allegations of insider trading and market power exercise have all fuelled conjectures that Europe’s markets are inefficient.

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[8] Comparative studies show that German and British OTC prices are highly correlated with their respective power exchange prices (see Figure 24 for example).

[9] Haldrup and Nielsen (2004) for example find a regime switching long memory model to adequately forecast spot prices in the Nordic market. Periodic heteroskedastic autoregressive fractionally integrated moving average model models were proposed by Carnero et al. (2003), and Cartea and Figueroa (2005) suggests jump diffusion models. Overviews of the relevant literature can be found in Bunn (2004), Knittel and Roberts (2004) and Skantze and Ilic (2001).

This thesis is designed to empirically analyze whether or not European electricity prices are the result of perfectly functioning competitive markets by focusing on two sources of inefficiencies in wholesale markets, namely, barriers to cross-border trade and the exercise of market power. Both issues are introduced in the next two sections.

I.2 Market Power

During the process of reform, not surprisingly, more attention was paid to incorporating the natural monopoly, i.e. the transmission and distribution networks, within a competitive market structure. However, the remaining vertical and horizontal integration as well as the widespread existence of national incumbents often provide significant market power. In electricity generation sectors throughout the world the combination of significant market concentration with high and/or increasing electricity prices put forth the hypothesis that market power was actually exercised. Consequently, the European Commission ordered an examination of the gas and electricity sectors to "investigate the [market power] allegations and to assess the reasons for rigidity in prices." These early results highlight the potential for market power in terms of market concentration, but fail to provide final evidence for its exercise.[10] Simply put, the exercise of market power often appears straightforward to the public, but hard evidence is difficult to produce. Economists have attempted to address this problem by applying several methodologies.[11]

A company is said to exercise market power if it profitably raises/lowers the market price above/below the competitive price level.[12] Therefore, demonstrating the exercise of market power encompasses two steps: First, it needs to be shown that a company's price-setting strategy differs from competitive behavior, and second, it is necessary to demonstrate that this strategy is profitable for the utility. Most studies assume that companies (can) exercise market

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[10] The sector inquiry (EC 2007, p.150) supposes that physical withholding and overbidding might play a role.

[11] The first theoretical studies of market power in the power sector were undertaken in the 1970s, e.g., Weiss (1975). The political discussion, however, is almost as old as the electricity industry. Stier (1999) for example shows that earlier than 1910 the monopolization of electricity supply in Germany stimulated a broad political discussion about how the state should intervene to prevent a sustainable monopoly. The question was whether the state should create a state-owned electricity segment to compete with the expanding RWE or whether it was more efficient to use the powers of the state (e.g., building laws) to regulate the private sector. Various political and financial reasons led Prussia to finally choose the first alternative. It would be an interesting exercise to study what would have happened if unbundling had been an option in the relatively liberal policy climate one hundred years ago.

[12] Stoft (2002, p.318).

power mainly by bidding above marginal cost.[13] Consequently, Borenstein et al. (2002) state that there are essentially two monitoring strategies: one that deduces the exercise of market power from extraordinary price-cost difference, and another that attempts to directly reveal abusive company strategies by analyzing individual bidding and supply decisions. The first approach requires estimating the marginal cost of electricity production for a specific period and comparing it with the corresponding electricity prices. As the required data on individual prices, volumes, cost and production functions are generally unavailable, most academic studies confine themselves to analyzing the exercise of market power on a sector-wide level. Starting from the assumption that in an oligopolistic electricity wholesale market, companies can increase their profits by restricting their supply (physical withholding) or bidding above cost (financial withholding) the hypothesis that prices deviate from marginal cost is tested.[14] The major difficulty is obtaining reliable estimates for hour-by-hour electricity production cost. Despite being a homogenous good, electricity is produced by very different technologies. Each power plant features an individual marginal cost curve that depends on fuel prices, workload-dependent heat rate, inter-temporal cost (e.g., ramping cost, or opportunity cost of hydropower) and other factors. International trade, stochasticity of supply and demand and uncertainty add to the complexity. Finally, predicting the circumstances in which the generator with the highest marginal cost recovers its fixed cost remains unresolved.[15] As a result, the true cost of generation can only be approximated.[16] Despite these caveats, this approach is widely used because it allows assessing the size of market power exercise and its development over time.

The second approach analyzes each company’s data.[17] Again, the complexity of electricity production makes cast-iron proofs of market power behavior difficult even with such data. Showing that a company takes certain plants offline, notably in those moments when the resulting price development increase the value of its remaining production, for example, is no

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[13] Note that underbidding might also be ”appropriate” to create excess revenues for the vertically integrated electricity supply companies (e.g., Kühn and Machado (2004)).

[14] Newbery et al. (2005) provide a summary of some of the existing electricity market monitoring approaches. Studies for certain European markets have been produced by: Fehr and Harbord (1993), Short and Swan (2002), Fabra and Toro (2003), Evans and Green (2003), Müsgens (2006), Schwarz and Lang (2006), Hirschhausen et al. (2007), Wolfram (1999), Wolak and Patrick (2001), Burns et al. (2004), and Sweeting (2004).

[15] See for example, Hartley and Moran (2000), Brennan (2002) and Weber (2002).

[16] In describing the difficulties of estimating generation cost, Swider et al. (2007) challenge a series of existing studies of the German market.

[17] Examples are Wolak and Patrick (2001), Wolfram (1998), Bushnell and Wolak (1999), Wolak (2000) and Puller (2001).

evidence for physical withholding.[18] In the potentially profitable on-peak demand periods, more (and older) power plants operate and thus outages become more probable.[19]

Analyzing the bidding behavior is only possible when data on individual players' bidding behavior are available and trading via the observable market is compulsory.[20] Provided with data on bidding behavior on certain spot markets, evidence for strategic bidding was found.[21] Transparent compulsory markets are, however, uncommon, restricting the number of analyzable cases.

Alternative testing approaches that require less-specific data are desirable. In this context, econometric time-series and cross-sectional techniques could provide a valuable complementary methodology for revealing signs of market power exercise. But quantitative approaches such as cross-country comparisons of electricity prices or case studies of the electricity price effects of mergers or generation cost shocks have rarely been employed. To rectify the situation, this dissertation develops and adapts methodologies to study the company level usage of interconnectors (Chapter V); the interaction of prices and certain generation cost components (Chapter II); and the pass-through of cost shocks (Chapter III) utilizing European market data.

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[18] Examples for this approach are Joskow and Kahn (2002) as well as Patton et. al. (2002).

[19] Joskow and Kahn (2002) argued that during the California electricity crisis of 2000-2001, some companies increased profits by deliberately withholding physical capacity. Equipped with company data, Harvey et al. (2004) were able to successfully challenge this evidence based on the argument that outages become more likely at higher loads.

[20] If spot market participation is voluntary, trading via the non-transparent OTC market makes the observable spot market bids difficult to interpret.

[21] Such studies have, for example, been undertaken by Fabra and Toro (2005) and Bovenzi (2007) for the Spanish and by Hortacsu and Puller (2005) for the Texas spot markets.

I.3 Cross-Border Trade

Increasing cross-border electricity trade improves total welfare via different channels: *First*, if supply and demand conditions in the linked markets are not fully correlated, the common on-peak demand is usually lower than the sum of the individual on-peak demands, thus increasing the security of supply of both systems (or allows substantial cost reductions of the security margins). *Second*, connecting systems with different plant portfolios (and thus marginal generation cost curves) allow for substantial cost reductions (the link between hydropower-dominated Switzerland and nuclear-dominated France, for example, provides cheaper night-time electricity for Switzerland and cheaper daytime electricity for France). *Third*, in addition to smoothing the cost curve that allows lower marginal cost for each demand scenario, the cost curve for ancillary services (like minute reserve or frequency control) is also stretched (and costs are reduced). *Finally*, the scale efficiencies of electricity generation become negligible at a certain level of size. Thus, in a sufficiently large market, electricity generation should not be a natural monopoly.[22] Therefore, a common wholesale market that supports a significant number of sustainable competitors could efficiently mitigate market power.[23]

Historically, the majority of (West[24]-) European cross-border transmission lines were engineered and constructed to increase the security of supply of the mainly autarkic national electricity systems.[25] International electricity trade usually occurred in the form of bilateral agreements between national monopolies. The world was small enough that transmission operators often knew one another: one anecdote relates an instance when the BEWAG (former Berlin vertically integrated monopolist) called his Polish counterpart to ask for more power after a BEWAG plant went down.

As companies unbundled, markets opened and third-party access was implemented, new competitors and traders clamored to enter this often highly profitable market. The

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[22] Based on an estimate of Christensen and Greene (1976), Kahn (1995) suggests that 4000 Megawatt (MW) is a fairly accurate threshold.

[23] For the benefits of electricity interconnectors, see Turvey (2006).

[24] In the Council for Mutual Economic Assistance (COMECON) period, the high-voltage system of the German Democratic Republic, Czechoslovak Socialist Republic, Poland and other COMECON Members was jointly operated by the Central Dispatch Organization of the Interconnected Power Systems (CDO/IPS) in Prague (Lagendijk (2005)).

[25] For an overview of the history of cross-border transmission networks in Europe, see Lagendijk and Schipper (2006).

marketization of cross-border electricity trade, however, proceeded only gradually as the necessary institutions were introduced step-by-step. The challenge was to create an institutional framework that allowed for the optimal use of an existing transmission infrastructure that had never been designed to host significant and fluctuating commercial flows. The major technical constraint was the insufficiency of cross-border transmission capacity. Therefore, the "right" to use the limited capacities in times of excess demand had to be allocated to the interested parties. Since the EC did not set forth the introduction of a common mechanism, member states were free to negotiate bilateral agreements, and a variety of rationing methods were created. The congestion management methods included the uneconomic first-come, first-served approaches used by Belgium and France before 2006; the explicit auctions used by Germany and the Netherlands; and the implicit auctions used in the NordPool area.[26]

Apart from allocation distortions, the non-auction-based congestion management methods also failed to provide data on the utilization of the interconnection lines and the actual willingness to pay for the limited capacities. Therefore, the EU implicitly banned them in Regulation 1228/2003, by requiring congestion management to be organized in a "market-based" manner. Consequently, three types of capacity-auctions prevail in 2007: the allocation of transmission rights via implicit auctions; bilateral explicit auctions and coordinated explicit auctions.[27]

In implicit auctions, the markets for electricity and for transmission rights are pooled. A market operator collects bid and offer curves at each of the linked electricity markets. It computes optimal prices for each market as well as the flows between them with respect to the transmission constraints. Consequently, the prices at only two electricity markets will differ if bringing more electricity from the lower- to the higher-price region is not possible. The difference between two regional market prices for the corresponding right to transmit electricity is called the shadow price.

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[26] For details on the congestion management methods see ETSO (2004). The advantages and disadvantages of these methods are discussed in ETSO (2004) and CONSENTEC (2004).

[27] In December 2006, Belgium, France and the Netherlands introduced an additional scheme called market coupling that combines implicit and explicit auctions.

In bilateral and coordinated explicit auctions, the markets for electricity and for transmission rights are separated.[28] Therefore, a trader intending to sell German electricity in the Netherlands must purchase both the electricity and the right to use the transmission line. Transmission rights for the different delivery periods (hour, day, month, and year) are usually sold in sealed-bid auctions.

Table 1 illustrates the necessary steps for performing international arbitrage in the day-ahead market: the transmission capacity available in the daily auction is announced; bids are submitted; the auction is closed; and the winning results are announced. While the transmission capacity auction is held, the power exchanges are collecting bids and selling offers. At a specified time after the auction results are published, the power exchanges close the bidding, calculate the spot prices, and announce them. Therefore, a trader wanting to do arbitrage operations by selling cheaper German power to the Netherlands must first bid on transmission capacity absent knowledge of the exact spot prices and then submit its sell offer for electricity at the Amsterdam Power Exchange (APX) knowing only the transmission auction results. After receiving the APX price, the transmission capacity price and the quantities it has purchased, the trader can now bid to purchase German power at the European Energy Exchange in Leipzig (EEX).[29] From this example, it is clear that explicit auctions do not necessarily result in (full informational) arbitrage freeness. This is confirmed empirically by two observations: first, electricity often flows against the price differential (see Figure 20 in Chapter V) and second, electricity price differences do not equal capacity auction prices (see Figure 11 in Chapter IV).

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[28] In bilateral auctions, only the transmission rights between two adjacent markets (e.g. Germany and the Netherlands) are sold, while in coordinated auctions, the transmission rights between more than two markets are sold at once (e.g. Czech Republic, Germany and Poland). Therefore, a single coordinated auction is in general more efficient because it can better account for the physical interactions in a meshed network (loop-flows).

[29] This example ignores the possibility that the trader may possess long-term contracts in one or more of the three markets.

Table 1: Timing of cross-border auctions and spot markets in 2005

	Cross-Border Auctions		Power Exchanges		
	German-Dutch[30]	German-Danish[31]	APX	Elspot[32]	EEX
Announcement of available transfer capacity	8:30	9:00			
End of bidding	9:00	9:30	10:30	12:00	12:00
Publication of results	9:30	10:00	11:00	12:00	12:15

To understand the functioning of cross-border trade, it is useful to study international price differences and international price shock diffusion. Although numerous articles analyzing European wholesale spot prices have appeared recently, there has been little research on the interactions of prices at different exchanges. Studies of the interrelations of regional markets mostly focus on non-European countries. Popova (2004) models the prices in the twelve transmission zones of the Pennsylvania Jersey Maryland market via a spatial error model, finding that spatial correlations are an important factor in price determination. Jerko et al. (2002) uses a structural Vector Auto Regression to analyze interactions of spot prices in the Western US. Videbeck (2004) analyzes the different prices at the nodes of the New Zealand pool. DeVany and Walls (1999) use co-integration analysis to assess the arbitrage freeness of electricity spot prices in the Western US between different locations.

While efficiency of cross-border trade has been analyzed for the US the inefficiencies of European-style explicit auction have not been subject to empirical investigations. This thesis employs two methods to quantitatively assess the functioning of West and Central European cross-border electricity trade. Chapter IV analyzes how market integration has developed over time and whether explicit auctions induce arbitrage freeness. A case study on the causes of the detected inefficiencies is provided in Chapter V.

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[30] This example relies on the capacity auction procedure for capacities between the German transmission system operator E.on Netz and the Dutch transmission system operator TenneT.

[31] This example relies on the capacity auction procedure for capacities between the German transmission system operator E.on Netz and the West Danish transmission system operator ELTRA.

[32] Elspot is the Nordic spot market on which electricity for the West Danish price zone is traded.

II A Markov Switching Model of the Merit Order to Compare UK and German Price Formation

II.1 Introduction

This chapter introduces a stylized model of the price formation in competitive electricity spot markets. The goodness-of-fit and the parameter estimates of the model provide a measure for the fuel cost-reflectiveness of wholesale prices that can be compared across countries and time. The model allows us to track the differences in the national price formation mechanisms, and shows the market's developments and their inefficiencies. Thus, a thorough interpretation of the obtained cost-reflectiveness of national prices could provide a first indicator about a market's efficiency. Therefore, instead of calculating the absolute deviation of the electricity price from the respective generation cost, we establish a stylized model of the marginal electricity generation cost. Next, the model is estimated over time assuming that the wholesale prices equal marginal cost. Last, we compare the empirical parameters and the residuals of the estimation across countries to assess where and when prices are best explained by their fundamentals, and to identify deviations from competitive price setting.

The next section introduces selective data about the two countries used in our model: the UK and Germany. Section 3 presents the model, Section 4 presents the results and an interpretation, and Section 5 concludes.

II.2 Data

The German and UK electricity systems are comparable in size (see Table 1). Conventional thermal power plants account for most of the electricity generation (65% in Germany and 77% in the UK). One obvious difference is that the UK does not use lignite for which it compensates by an increased share of natural gas. However, both countries differ markedly in market structure and design. While the UK has two decades of experience with market opening and regulation, Germany only addressed sector reforms in the first part of this decade, and only established a national regulator in mid-2005. The four privately owned transmission system operators in Germany retain significant stakes in generation (together 80% of total capacity) and distribution. The integration of the two major German players, E.on and RWE, and their natural gas affiliates enhances their dominance. The situation in the

UK, on the other hand, is more balanced. The transmission system operator (TSO) is unbundled and national regulation is effective. The nine largest generation companies together own only 68% of the capacity. Although they are integrated with electricity and gas suppliers, no one has a position comparable to the "big four" in Germany.

Table 2: Gross electricity generation (2005)

	Germany	UK
Hydropower plants	4 %	2 %
Nuclear power plants	26 %	20 %
Coal-fired power plants	21 %	34 %
Lignite-fired power plants	23 %	
Natural gas-fired power plants	11 %	38 %
Others	15 %	6 %
Annual gross electricity generation in TWh	**620**	**401**
Source: Eurostat[33]		

Both countries' wholesale markets are particularly suited to our model. *First*, neither market is endowed with significant hydropower capacity. This is an advantage because our model is unable to reproduce the dynamic opportunity cost assessment required for analyzing the marginal cost of a hydro plant. *Second*, both markets provide reference prices. Hourly spot electricity prices for Germany are obtained from the EEX (prices are formed by day-ahead, two-side, one-shot, sealed-bid uniform-price auctions). By contrast, half-hourly spot prices at the UK Power Exchange (UKPX) are obtained in 48-hour continuous trading until a half-hour ahead of delivery.[34]

Table 3: Summary of the data sample (February 2002-December 2006)

		Germany			United Kingdom		
	Unit	Source	Mean	Variance	Source	Mean	Variance
Electricity off-peak	€/MWh$_{el}$	EEX	29.5	160	UKPX	31.4	220
Electricity on-peak	€/MWh$_{el}$[35]	EEX	48.3	839	UKPX	44.9	764
Gas spot price	€/MWh$_{th}$	TTF	13.5	26	NBP	14.1	70
Coal spot price	€/MWh$_{th}$	ARA	5.8	1	ARA	5.8	1
Emission allowance	€/EUA	EEX	6.8	90	EEX	6.8	90

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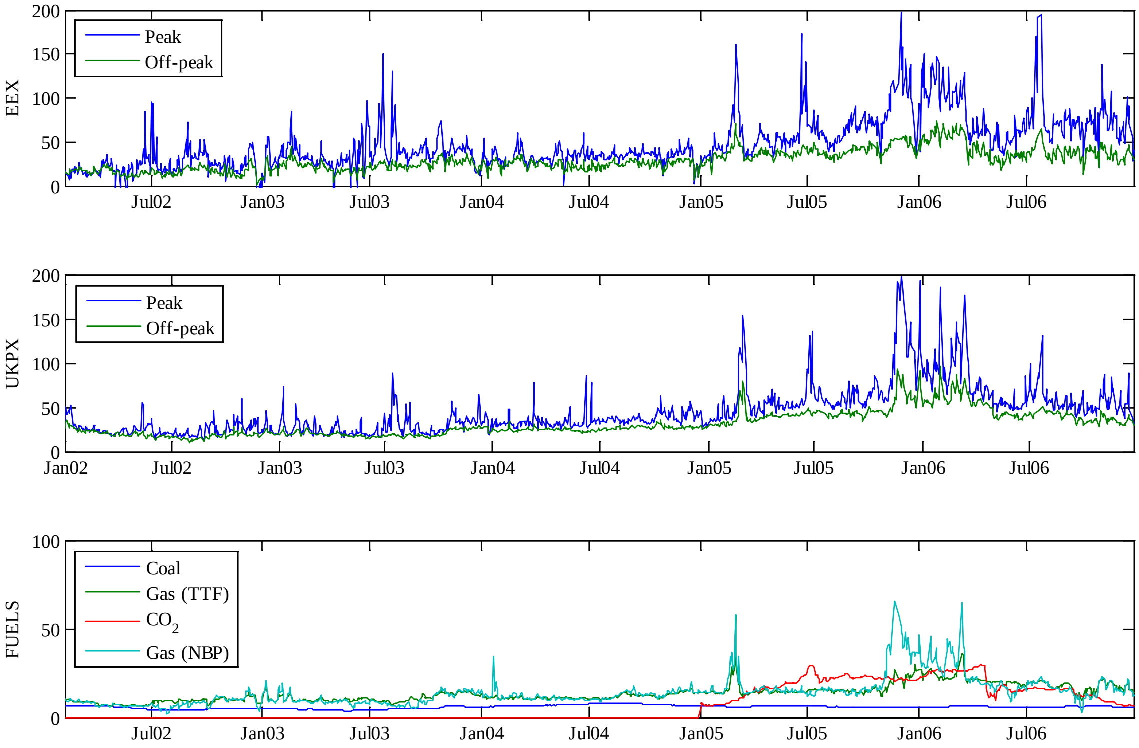
[33] The data were retrieved from [http://epp.eurostat.ec.europa.eu] via the data navigation tree.

[34] Most of the high-frequency price and volume data employed in this dissertation were not freely available, but could only be obtained upon request from the corresponding data providers. The usage rules did not allow a publication of the original data in this dissertation.

[35] MWh$_{el}$ stands for one Megawatt hour of electric energy.

Because our model is only meaningful in the short and medium run, we used daily price notations for all commodities. Since no daily German gas and coal prices were available, we employ the respective values of the Dutch markets for natural gas (TTF[36]) and coal (ARA[37]).[38] These data have been obtained from Datastream[39]. The sample contains data from February 2002 to December 2006, eliminating weekends and holidays.[40] We converted the fuel prices into Euro per calorific value measured in Megawatt (€/MWh$_{th}$) to simplify interpretation. The respective data sources for the three commodities for Germany and the UK are summarized in Table 2. Figure 1 depicts the series of spot prices; on-peak and off-peak prices approximately doubled between 2002 and 2006. Gas prices also doubled, whereas coal prices reached their initial level at the end of 2006.[41] Emission allowance prices increased from € 10 to € 30 and then returned to € 10 in the same period.

Figure 1: Development of the spot price series 2002-2006 (in €/MWh)



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[36] TTF stands for Title Transfer Facility, a virtual trading point for natural gas in the Netherlands.

[37] CIF ARA coal prices (CIF refers to Cost, Insurance and Freight and ARA refers to Amsterdam, Rotterdam, Antwerp).

[38] It should be noted that gas and especially coal prices in Germany should exceed Dutch fuel prices by some constant because of transportation costs.

[39] Thomson Datastream is a commercial financial statistical database.

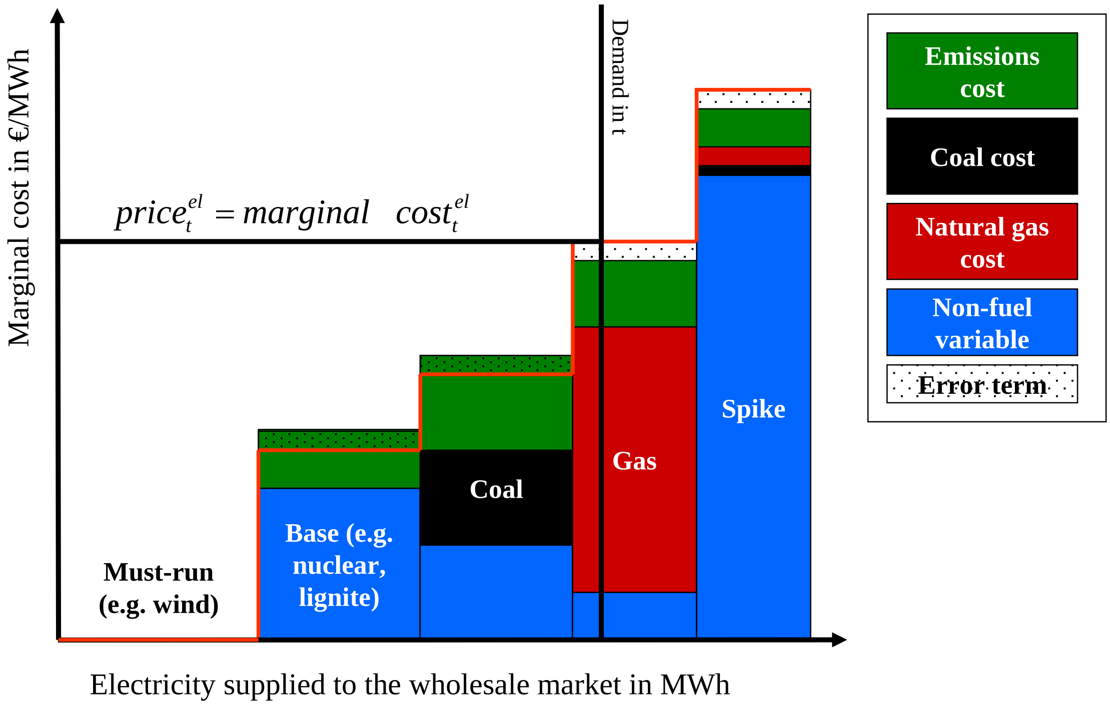
[40] This has the positive side-effect of significant reductions in weekly seasonalities.

[41] Datastream derives the daily coal price notations by converting the monthly coal prices in dollars into Euros using the daily exchange rate. Thus, the increasing Dollar-Euro exchange rate limited the effect of rising coal prices for European coal consumers.

II.3 Model

As mentioned, electricity is generated by a variety of technologies. Since the differences of marginal costs of power plants with the same technology are small compared to the cost difference between dissimilar technologies, we can approximate the marginal cost curve of the entire electricity system via a stepwise function (see Figure 2).[42]

Figure 2: Stylized example of the stepwise marginal cost function[43]



In detail, we can model the electricity price at time t as the marginal cost of the last required technology to meet demand. In the short run, the costs of a plant should correlate closely with its fuel and emission costs. Since the fuel efficiency of technologies changes rather slowly, fuel and emission costs are predominantly determined by the respective prices. Thus, we can create a time series model that endogenously infers the cost structures of each class of plant and deduces which is marginal at each point in time using only the inputs of fuel, emission and electricity prices.

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[42] Typical non-dispatchable, must-run generation includes wind, run-of-river hydro and combined heat and power plants (in winter).

[43] The error term might be positive or negative. Consequently the marginal cost might in some cases be lower (base and coal in the stylized representation) or higher (gas and spike in the stylized representation) than the sum of fuel, emission and other variable cost.

Generally, our model consists of two procedures: a routine that decides which class of power plants sets the price (i.e., is marginal) and a mechanism that reproduces the electricity price formation for each class. For each technology regime[44] $S_t = 1,2,...,m$ we assume the marginal costs at time $t \in 1\ldots T$ to be the sum of a state dependent stochastic component and a state dependent weighted linear combination of the k explanatory variables. That is, the weighting vector β depends on the marginal technology in time t. Thus, the weighting vector specific for the technology state i (i.e., the vector that applies for all t where $S_t = i$) is denoted β_i. The state dependent stochastic component in time t for the technology state i is denoted $\varepsilon_{t,i}$. The set of explanatory variables stored in the k rows of the matrix $X_{1:T}$ may contain, for example, a constant, a time trend and different dummy variables, as well as gas, oil, coal and emission certificate prices.[45] Depending on the chosen explanatory variables and the technologies, the model can be written as

$$price_t^{el} = \begin{cases} \beta_1 \times X_t + \varepsilon_{t,1} & S_t = 1 \\ \beta_2 \times X_t + \varepsilon_{t,2} & S_t = 2 \\ \vdots & \\ \beta_m \times X_t + \varepsilon_{t,m} & S_t = m \end{cases} \tag{1}$$

When the process that determines the marginal technology at time t is assumed to be Markovian[46] and $\varepsilon_{t,i}$ is assumed to be independent and identically normal distributed in each technology state i, (1) can be estimated using a Markov Switching Regression. We first convert the model into state space form with the states (or regimes) representing the different technologies. To make the model computable, we specify the transition matrix as $Prob\left(S_t = i \mid S_{t-1} = j\right) = p_{i,j}$, i.e. with time invariant exogenous switching probabilities.[47]

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[44] The terms state, regime, technology and technology regime are used synonymously.

[45] The notion $1:T$, here and in the remainder of the chapter, refers to the corresponding element at all discrete time points between $t = 1$ and $t = T$.

[46] A Markov process is characterized by the fact that the likelihood of a given future state, at any given moment, depends only on its present state, and not on any past states.

[47] Including demand and weather conditions in the switching probabilities could improve the estimation; modeling switching cost as threshold variables in the state-equation may make the estimates even more realistic. However, the problematic implementation is left to further research.

Thus, the model is fully described by

$$price_t^{el} = \beta_{S_t} \times X_t + \varepsilon_{t,S_t} \qquad (2a)$$

$$S_t = 1...m \qquad (2b)$$

$$Prob(S_t = i \mid S_{t-1} = j) = p_{i,j}, \quad \forall \quad 1 \leq i, j \leq m \qquad (3)$$

where X_t is the t^{th} column of the ($k \times T$) matrix $X_{1:T}$ of explanatory variables and β_{S_t} is the state dependent ($1 \times k$) row vector ($\beta_{S_t,1}, \beta_{S_t,2},...\beta_{S_t,k}$, where $\beta_{S_t,k}$ is the coefficient for the k^{th} explanatory variable).

The presented stylized merit order (see Figure 2) implies that there are only four types of power plants with different cost structures.[48] The marginal cost for each technology depends only on the fuel consumption, emissions and non-fuel variable costs. Thus, the explanatory variables are: a constant, the coal price, the gas price and the emission allowance price. We can impose certain zero restrictions on β_{S_t} because the marginal cost of coal plants should not depend on the gas price. The interpretation of the remaining coefficients is then straightforward. The constant represents the non-fuel variable cost of this type of plant. The fuel coefficient for the used fuel is the inverse of the heat rate of the plant (when electricity price and fuel price are both measured in the same unit, i.e. €/MWh). The coefficient for the emission certificate prices represents the amount of emissions per unit of electricity.[49] When interpreting the results, we must bear in mind that we do not address the endogeneity problem (i.e. we ignore the reality that gas and emission allowance prices also depend on electricity prices) and the number of states selection problem (i.e. we ignore that the "real" number of states might be different from our choice).

Our non-linear model makes it difficult to deduce theoretically the distribution of the parameters conditioned on the data. Thus, we rely on the approach by Schweri (2004) who proposes to address this issue by using the Gibbs sampling technique.[50] The general idea of Gibbs sampling is to repeatedly draw each parameter conditioned on the data and all other

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[48] Must-run generation like wind and run-of-river hydro are not included since they can be considered as a reduction of net electricity demand.

[49] The units match accordingly: $€/MWh_{el} = €/MWh_{el} + MWh_{el}/MWh_{th} \times €/MWh_{th} + tCO_2/MWh_{el} \times €/tCO_2$

[50] See Krolzig (1997, p.148ff).

parameters. This procedure is iterated many times, always conditioning on the latest draws of the other parameters. To estimate (2) and (3) via Gibbs sampling, the density function $g(\bullet)$ has to be separated. Schweri (2004) proposes the following dissection:

$$\begin{aligned} & g\left(S_{1:T}, \beta_{S_t}, \sigma_{S_t}, p_{i,j} \mid price^{el}_{1:T}, X_{1:T}\right) = \\ & g\left(\beta_{S_t}, \sigma_{S_t} \mid price^{el}_{1:T}, X_{1:T}, S_{1:T}\right) g\left(p_{i,j} \mid S_{1:T}\right) g\left(S_{1:T} \mid price^{el}_{1:T}, X_{1:T}\right) \end{aligned} \tag{4}$$

According to the dissection in (4) the distribution of the parameters conditioned on the data can be deduced using the four steps proposed in Schweri (2004, p.34ff):

1) Deduce $g\left(S_{1:T} \mid price^{el}_{1:T}, X_{1:T}\right)$ from $g\left(S_T \mid price^{el}_{1:T}, X_{1:T}\right)$ and $g\left(S_t \mid S_{t+1}, price^{el}_{1:t}, X_{1:T}\right)$ by backward iteration. Thereby $g\left(S_t \mid S_{t+1}, price^{el}_{1:t}, X_{1:T}\right)$ is calculated from $g\left(S_t \mid price^{el}_{1:t}, X_{1:T}\right)$ which is obtained by the Hamilton filter.

2) Draw the beta-distributed switching probabilities $p_{i,j}$ given $S_{1:T}$.

3) Draw the β_{S_T} given $price^{el}_{1:T}$, $X_{1:T}$, $S_{1:T}$ and σ_{S_t}.

4) Draw the σ_{S_t} given β_{S_T}, $S_{1:T}$, $price^{el}_{1:T}$ and $X_{1:T}$.

A detailed description of the steps and its technical implementation appears in Schweri (2004, p.33-54) who also provides the corresponding Matlab code.[51]

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[51] As the author was unable to find any other implementation of a Bayesian Markov Switching Vectorautoregression in the literature he had solely relied on the excellently documented Matlab code provided in the diploma thesis by Urs Schweri (2004). The methodology used in this chapter reproduces the regime switching model without Kalman Filtering of Schweri (2004, p.33-54). The author would like to thank Urs Schweri for his welcoming reply to arising questions.

Table 4: Dimension and notation of variables used in the Markov-Switching Model

Variable	Dimension	Explanation
$price_t^{el}$	*scalar*	Explained variable: electricity price series
t	*scalar*	time index
S_t	*scalar*	Indicator of the regime in time t
k	*scalar*	number of explanatory variables
m	*scalar*	number of states
T	*scalar*	termination date
$p_{i,j}$	*scalar*	probability to switch from state i to state j.
X_t	$k \times 1$	vector of explanatory variables at time t (constant, considered fuel and emission price series)
β_{S_t}	$1 \times k$	state dependent coefficient vector
ε_{t,S_t}	*scalar*	state dependent error term
σ_{S_t}	*scalar*	state dependent error variance

The described estimation strategy features certain drawbacks:

(1) Due to the definition of prior expectations, that (might) drive the posterior distribution of the parameters, the results are not purely data driven (Schweri, 2004, p.29)

(2) The assumptions on the distribution of error terms (independent, identical distributed) are not met for all time series (see Table 12).

(3) The results might depend on the selection of starting values.

(4) At small numbers of draws the results are not stable and there is no final certainty that the model converged to the global maximum. Thus, a high number of draws is chosen that make the estimation computationally burdensome.

Despite these caveats, the presented estimation strategy was the approach the best suited to estimate the described model, the author was able to find in the literature. As discussed in Krolzig (1997, p.175) in contrast to the Expectation Maximization approach the Gibbs sampling approach provides the posterior distribution of the parameters. Furthermore, it allows the inclusion of prior knowledge which is essential for our modeling strategy (see next section).

II.4 Results

(a) Estimation Results

To estimate (2) & (3), a sensible choice of the dependent variable (i.e. the electricity price series) is crucial. As demand is highly volatile throughout the day, we may expect that up to five regime switches (nuclear->coal->gas->coal->nuclear) occur every day. Using a continuous hour-by-hour series is inadequate because regime persistency ($p_{i,i} >> p_{i,j}$) is required for stable estimates. Thus, it is preferable to divide the continuous series into 24 day-by-day series, each of which represents one hour. However, we note that estimating (2) & (3) for 24 (or even 48) series is impractical because of the similarity of some series (e.g. 3rd and 4th hour data), and the estimation procedure is computationally burdensome. We can reduce the series to two still retain most information by drawing on a weighted average of on-peak (8am-8pm) and off-peak (8pm-8am) prices. We obtain the optimal weighting vector (in terms of variance explained) by Principal Components Analysis (PCA).[52] Later, we exclude dates with electricity prices above 200€/MWh because such extreme price spikes could distort our analysis and cannot be explained by fuel cost fundamentals.[53]

We estimate (2) & (3) for the off-peak and on-peak series for the German (EEX) and the British (UKPX) markets. In all four cases (EEX off-peak, EEX on-peak, UKPX off-peak and UKPX on-peak), we apply a model in which spot electricity prices are explained by spot gas prices, spot coal prices and the respective emission allowance price. We omit oil prices and a trend after our initial estimations have suggested that they are not significant for any state. Variance and all β coefficients are selected to be state dependent.[54] To capture the effect that

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[52] Principal Component Analysis was developed to find those linear combinations of the elements of the columns of a data matrix that explain the majority of the variance of the data. A standardized linear combination is a weighted average ($\delta' X$) of the columns of X where δ is a vector of length one. Maximizing the variance of $\delta' X$ leads to the choice $\delta = \gamma_1$, the eigenvector corresponding to the largest eigenvalue λ_1 of the Covariance Matrix. This is a projection of X into the one-dimensional space, where the components of X are weighted by the elements of γ_1. $Y_1 = \lambda_1'(X - \mu)$ is called the first PC. This projection can be generalized to the second, third, and pth PCs by using the second, third, and pth largest eigenvalues and their corresponding eigenvectors. For the technical details see, for example, Haerdle and Simar (2003).

[53] Even burning expensive oil (50€/barrel) in an inefficient generator (heat rate of 20%) would only justify marginal cost of ~ 150€/MWh$_{el}$ (0.625 barrel/MWh$_{th}$ x 5 MWh$_{th}$/MWh$_{el}$ x 50 €/barrel). For the modeling of electricity price spikes, see Lang and Schwarz (2007).

[54] Note that state dependent variance is straightforward since high electricity price regimes are characterized by higher variance.

switching from one marginal technology to another only occurs when demand or supply conditions change significantly, we predefine some persistency.[55]

Choosing the number of states is based on goodness-of-fit; interpretability with respect to the stylized merit order; and comparability. We measure goodness-of-fit using the Schwartz information criterion, which suggests that either three or four regimes are appropriate, depending on the case.[56] The assumed stylized merit order suggests that there are three regimes in off-peak (base, coal, gas) and three regimes in on-peak (coal, gas, spike). For ease of presentation and comparability, we use the three-state specification.

Table 5: Results of the switching regression with non-informative priors

	freq	$\beta_{Constant}$	β_{Coal}	β_{Gas}	β_{CO2}	Mean	σ^2
Germany on-peak (R^2=75%)							
State1	35%	**12.5** (+/-7.0)	**-1.27** (+/-1.23)	**1.60** (+/-.40)	**1.12** (+/-.17)	35.0	60
State2	44%	**18.8** (+/-5.0)	**-1.04** (+/-0.69)	**2.06** (+/-.29)	**1.32** (+/-.12)	44.1	40
State3	22%	**28.6** (+/-11.5)	2.41 (+/-3.09)	0.75 (+/-.82)	**2.15** (+/-.58)	78.0	790
Germany off-peak (R^2=92%)							
State1 „Coal“	38%	-1.0 (+/-4.0)	**2.02** (+/-0.62)	**0.60** (+/-.14)	**0.66** (+/-.07)	24.0	19
State2 „Coal“	40%	3.4 (+/-3.5)	**1.63** (+/-0.59)	**0.96** (+/-.10)	**0.66** (+/-.06)	30.0	8
State3 „Gas“	21%	**15.9** (+/-7.1)	-0.03 (+/-1.28)	**1.11** (+/-.27)	**0.82** (+/-.15)	38.5	18
UK on-peak (R^2=90%)							
State1 „Coal“	47%	**2.7** (+/-1.7)	**2.13** (+/-.35)	**1.05** (+/-.13)	**0.98** (+/-.06)	30.0	10
State2 „Mix“	40%	**10.6** (+/-5.1)	**1.47** (+/-.81)	**1.42** (+/-.24)	**0.91** (+/-.14)	46.1	37
State3 „Gas“	13%	**24.5** (+/-14.5)	1.29 (+/-2.91)	**1.85** (+/-.26)	**0.80** (+/-.44)	93.7	434
UK off-peak (R^2=94%)							
State1 „Mix“	63%	**3.0** (+/-1.6)	**1.67** (+/-0.22)	**0.89** (+/-.09)	**0.77** (+/-.03)	28.9	4
State2 „Coal“	26%	**6.2** (+/-2.7)	**2.38** (+/-0.40)	**0.27** (+/-.14)	**1.16** (+/-.06)	26.8	2
State3 „Mix“	11%	**12.9** (+/-9.3)	0.84 (+/-1.53)	**0.82** (+/-.14)	**0.78** (+/-.23)	56.3	83

(+/-) = Half of the two-sided 95% confidence interval width. Bold empirical parameters are significantly different from zero.
Freq = relative frequency that state *i* had the highest probability.

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[55] The probability of remaining in the current state was set to 0.67 whereas the probability of switching to another state was adjusted to 0.16. Giving the prior a modest variance of approximately 0.1 implies that the beta-distribution of the p_{ij} - values is set to u_1 = 2 and u_2 = 1 on the main diagonal and u_1 = 1 and u_2 = 6 beyond the main diagonal.

[56] The Schwartz Information Criterion has been calculated for each case for one to four regimes using a model specification with non-informative priors for the entire sample. While the Schwartz Information Criterion favors a three-regime specification for the UK off-peak case, a four-regime specification is preferred for all other cases. This reflects the higher diversity of the German off-peak generation structure and must be borne in mind when interpreting the results.

The model is first estimated imposing (almost) no prior information on the parameters, switching probabilities and variances. Therefore, prior mean and starting values of the model parameters are set according to Table 10 (see Appendix). The estimation results for the three-state model with non-informative priors (see Table 5) suggest that the regime-switching model adequately captures the electricity prices. *First*, the R^2 is above 90% for all but the German on-peak series (75%). *Second*, the model performs significantly better than the single- state model. *Third*, almost all empirical parameters are significantly different from zero. Further, some states can be plausibly interpreted as technology regimes; e.g. the second state in the UK off-peak model could plausibly represent coal power plants (CPP). The coal coefficient (2.4) is close to the inverse heat rate of a CPP (~2.3-3.0), the CO_2 coefficient (1.2) is close to the emission rate of a CPP (~0.85) and the gas coefficient (0.3) is significant but small. Despite this evidence, in other respects the model with non-informative prior's deviates markedly from the assumed stylized merit order as certain states overlap[57] and cannot clearly be attributed to the assumed technologies. Moreover, the occurrence of negative parameters is not explained.

Using informative priors, it is possible to induce model outcomes that are plausible with respect to the stylized merit order. In all four cases (EEX off-peak, EEX on-peak, UKPX off-peak and UKPX on-peak), certain parameters are constrained to zero by applying tight prior distributions with mean zero.[58] Setting the mean and variance for the prior distribution of the parameters as well as the starting values according to Table 11 (see Appendix), the model is estimated using the described procedure.[59] This selection ensures that in each case three technology regimes (off-peak: base, coal and gas; on-peak: coal, gas and spike) exist that can be clearly distinguished. The coal and gas price parameter priors, for example, imply that each fuel is only significant in the corresponding regime.

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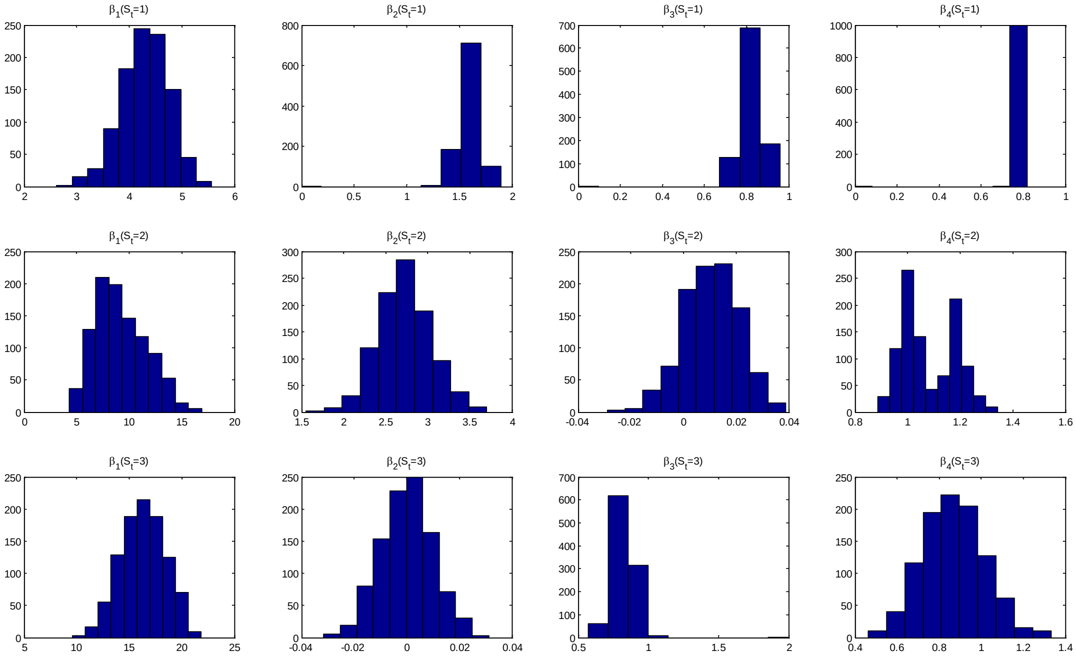
[57] In three of the four cases, the coefficients of at least two regimes cannot clearly be distinguished because the 95% confidence intervals for all of their coefficients overlap. This occurs for Germany peak (State1~State2); UK peak (State2~State3); and UK off-peak (State1~State3).

[58] In each of the steps, the posterior distribution $p(\theta|y)$ is given by the likelihood function $L(\theta|y)$ times the prior distribution $g(\theta)$: $p(\theta|y)= g(\theta) \times L(\theta|y)$.

[59] Due to the identification restriction, the sorting of the no-fuel state is crucial. Setting it as the first state implies that it has the lowest constant of all states, resulting in a baseload state.

Figure 3: Posterior parameter density for the UK off-peak case (informative priors)



The estimation results (see Table 6) indicate a good fit and the estimated regime characteristics allow us to make a straightforward interpretation. *First*, each state can meaningfully be attributed to a unique technology. *Second*, the average electricity prices in each regime are sorted according to the presented stylized merit order. *Third*, the estimated parameters are in an intuitive order of magnitude. In all four cases, we note that the coal coefficient in the coal state is always larger than the gas coefficient in the gas state, and the emissions allowance price has a stronger influence on the coal state. *Fourth*, almost all posterior parameter densities have a single maximum and are approximately normally distributed. This is illustrated at the UK off-peak example in Figure 3 where only the emission allowance posterior has two maxima.[60] This indicates that the model is generally well specified but that potentially two different coal states (e.g., “new” and “old”) with different emission intensities may exist.

The four technology regimes (base, coal, gas and spike) each feature unique characteristics. In the *base regime* electricity prices depend modestly on both fuel prices and emission allowance prices. Whether the gas and coal price dependence can be explained by ramping and balancing costs that figure into the marginal cost of typical baseload plants (nuclear, wind, lignite) or whether the dependence is due to endogeneity (e.g., baseload electricity as a

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[60] The results for all other cases may be obtained from the author upon request.

substitute for coal and gas) cannot be determined. Interestingly, the base state is the dominant state in the UK (80%) but not in Germany (38%). The *coal states* in all four cases feature highly significant influences of coal prices (1.57-4.10), insignificant influences of gas prices and highly significant influences of emission allowance prices (0.94-1.63). The average electricity prices in the coal state vary between around 40 in the UK off-peak and 30 in all other cases. In the *gas state*, all but the coal price coefficients are significantly positive. The gas price coefficients vary between 0.79 and 1.87, and the emission allowance price coefficients between 0.87 and 1.37. Finally the *spike state* is characterized by high prices, high variance and low frequency.

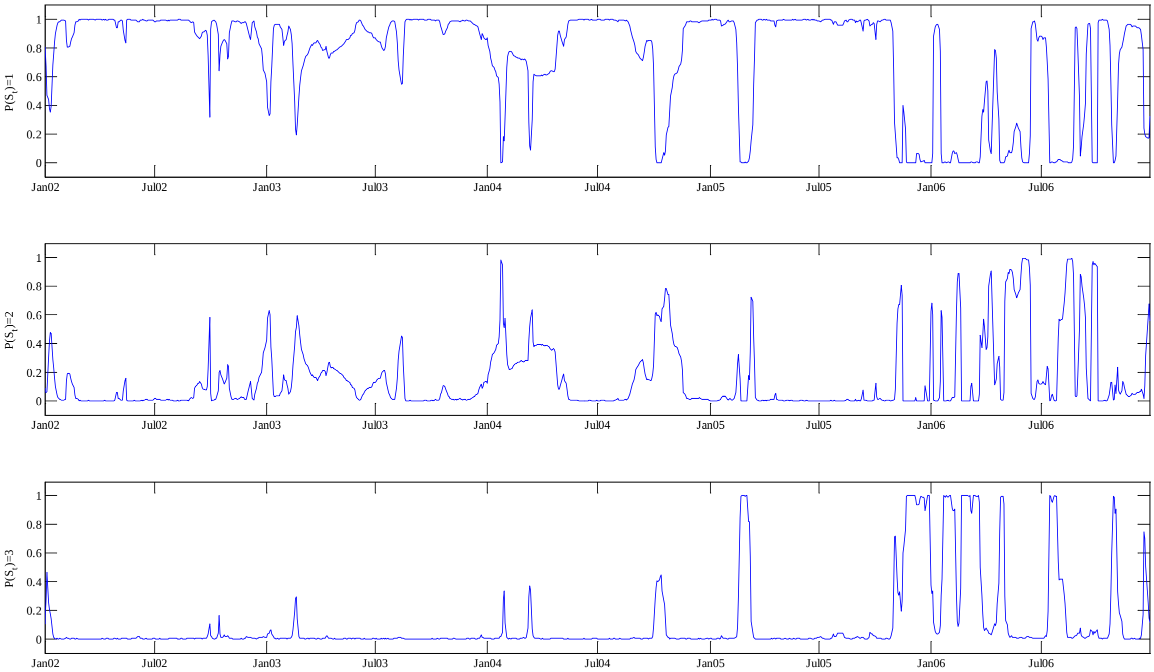
Table 6: Results of the switching regression with informative priors

	freq	$\beta_{Constant}$	β_{Coal}	β_{Gas}	β_{CO2}	Mean	σ^2
Germany on-peak (R^2=80%)							
State1 “Coal	30%	**7.4** (+/-4.6)	**2.00** (+/-.92)	0.00 (+/-.02)	**1.63** (+/-.13)	33.4	73
State2 “Gas”	57%	**14.7** (+/-3.5)	0.00 (+/-.02)	**1.87** (+/-.26)	**1.37** (+/-.14)	44.6	62
State3 “Spike”	13%	**91.9** (+/-6.1)	-0.41 (+/-.61)	-0.18 (+/-.43)	**0.93** (+/-.43)	97.1	800
Germany off-peak (R^2=90%)							
State1 “Base”	38%	**6.8** (+/-2.9)	**1.11** (+/-.43)	**0.35** (+/-.28)	**0.76** (+/-.13)	22.8	19
State2 “Coal”	34%	**13.7** (+/-2.8)	**1.57** (+/-.54)	0.01 (+/-.02)	**0.94** (+/-.16)	29.5	9
State3 “Gas”	28%	**19.8** (+/-1.9)	0.00 (+/-.02)	**0.71** (+/-.13)	**0.94** (+/-.11)	38.6	20
UK on-peak (R^2=87%)							
State1 “Coal”	37%	**2.6** (+/-1.5)	**4.10** (+/-.27)	0.01 (+/-.02)	**1.19** (+/-.07)	29.6	9
State2 “Gas”	53%	**13.2** (+/-2.4)	0.00 (+/-.02)	**1.79** (+/-.20)	**0.87** (+/-.12)	45.1	59
State3 “Spike”	10%	**89.2** (+/-6.2)	-0.59 (+/-.63)	**0.98** (+/-.30)	-0.30 (+/-.45)	103.6	710
UK off-peak (R^2=95%)							
State1 “Base”	80%	**4.3** (+/-.9)	**1.59** (+/-.17)	**0.82** (+/-.09)	**0.77** (+/-.03)	26.9	3
State2 “Coal”	11%	**9.2** (+/-4.5)	**2.72** (+/-.62)	0.01 (+/-.02)	**1.08** (+/-.17)	39.4	6
State3 “Gas”	9%	**16.4** (+/-4.0)	0.00 (+/-.02)	**0.83** (+/-.14)	**0.87** (+/-.28)	62.2	83
(+/-) = Half of the two-sided 95% confidence interval width. Bold empirical parameters are significantly different from zero.							

This being said, we note some reservations. *First*, it is difficult to explain that despite the straightforward identification of technology regimes, the cost structures of the technologies are unstable across countries and load periods. In fact, the 95% confidence intervals for the same coefficient in the same regime often do not intersect. For example, the confidence interval of the gas price coefficient in the gas regime for the German on-peak (1.87+/-.26) does not intersect with the same interval for the German off-peak (0.71+/-.13). *Second*, some coefficients are far “off” their expected values. For example, the inverse heat rate of a gas-fired plant should be somewhere around 2.5, but the estimated values are significantly smaller. *Third*, the assumption of normality for the residuals must be rejected for eight of the twelve cases at the five percent significance level (see Table 12 in the Appendix).

There are two potential explanations for the deviations of the estimation results from expectations: either the model is misspecified with respect to the real marginal cost of electricity production, and/or the underlying assumption that electricity prices are based on marginal cost is incorrect. While the first explanation probably holds to some degree,[61] there are reasons to believe that the second explanation is also plausible. Since the cost structure of a national power generation system is rather stable, intertemporal and international comparison of the model outcomes allows us to track the differences in the deviations of electricity prices from marginal cost.

Figure 4: Regime probabilities for the UK off-peak case (informative priors)



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[61] One cannot expect that a stochastic model with a very parsimonious specification can completely track the marginal cost of a complex electricity system. It is likely that increasing the number of technologies (i.e., states) and including more data (e.g. demand) could improve the outcomes.

(b) Intertemporal and international comparison of price formation

The *first* fact that merits attention is that the goodness-of-fit of our model is better in the UK case in both load periods (see Table 7). Using the Wilcoxon rank sum test[62], we find that the median absolute errors are significantly larger in the German case. *Second*, the constant is smaller and the fuel price coefficients are generally larger in the corresponding UK cases, indicating that fuel cost impacts a higher percentage of the UK's electricity prices. Furthermore, the posterior parameter variance is generally smaller in the UK.

This is strong indication that the regime switching model captures the UK electricity price development better than the German electricity price development. Several factors may be responsible for this: *First*, electricity generation in the UK relies more on the two modeled fuels (72% in the UK vs. 34% in Germany); estimations suggest that more than the considered three technology regimes are present in the German market. *Second*, both the UK natural gas and electricity markets feature a stronger link via common demand drivers and substitution than the Dutch natural gas and the German electricity markets.[63] *Third*, Germany is more fully integrated in the European electricity market, leading to a stronger influence of "foreign" power and fuel prices that are not considered in the stylized model.[64] *Fourth*, the UKPX price may include more information because the gate closure in the UK is only one hour ahead of schedule (in Germany it is at 12 a.m. on the day before delivery). *Fifth*, German electricity prices must reflect the higher added costs for reliability under stochastic wind- and heat-guided Combined Heat and Power plant (CHP) electricity production since these technologies comprise a substantial share of the fuel mix in Germany, unlike the UK. *Sixth*, the start-up cost and cost of reserve capacity are more important in an electricity system that is based largely on coal and lignite units. Since our model does not consider these cost types, the price-cost difference is potentially overestimated in the German market. Finally, the UK market is considered to be more competitive, potentially leading to more short-term, cost-dependent electricity prices.

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[62] For details on the Wilcoxon rank sum test see Freund and Wilson (2002, p.588ff).

[63] Note also that the feedback effects of the UK electricity price on the UK gas price may play a role. Knowing that the UK natural gas market is more mature and natural gas prices are less linked to the oil price than in Germany, it could very well be that endogeneity UK > endogeneity Germany.

[64] The UK electricity system is connected to the continental system via the Anglo-French electricity interconnector only (see Chapter V), while Germany has direct transmission lines to eight of its nine neighboring countries and Sweden. These physical characteristics are mirrored in the price developments (see Figure 10 on p.54).

Table 7: Goodness-of-fit (R²) of the regime switching model with informative priors

	Germany	UK	Wilcoxon rank sum test results[65]
on-peak	80%	87%	1,634,055***
off-peak	90%	95%	969,195***

The intertemporal comparison is also of interest. Estimating the model for the two sub-samples, 2002-2004 and 2005-2006, we find that the constants rose significantly from the earlier to the later stage (see Table 8). Consequently, a significant proportion of the electricity price increases in both the UK and Germany were not driven by fuel and emission cost increases. This can be attributed to two factors: first, it has been argued that in the sample period, electricity pricing switched from over-capacity-driven, short-term marginal cost (SRMC) pricing after liberalization to a less fuel-cost-dependent, long-term marginal cost pricing. This switching has been attributed to the reduction of excess capacities during the process of liberalization. A second explanation is that increasing concentration in the wholesale sector made exercising market power potentially easier.

Table 8: Regime-dependent constant in the early (2002-04) and late (2005-06) sub-sample

	Germany off-peak			Germany on-peak			UK off-peak			UK on-peak		
State	1	2	3	1	2	3	1	2	3	1	2	3
2002-04	5.5	14.2	17.8	4.6	9.3	17.1	8	13.1	86.8	2	12.3	90.7
2005-06	11.6	13.6	19.8	11.3	13.9	17	7.4	15.4	101.5	5.6	10.9	96.3

Figure 3 depicts the marginal state for every point in time as estimated in the model with informative priors for the UK off-peak case. What is striking about this example is that the dominance of the base regime ceased in the second half of 2005 while the coal and gas regime gained importance. This structural change (found in all four cases) may have been due to a fuel switch caused by high emission certificate prices or lower baseload generation margins produced by increasing baseload demand and/or decreasing baseload generation capacities.

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[65] We test the null hypothesis that the median of the absolute value of the residuals for the German and the British model are identical. The three stars indicate that the null hypothesis is rejected on the 99% significance interval.

II.5 Conclusion

The chapter compares the wholesale price formation mechanism in the UK and Germany. Applying a Markov Switching Regression, we provide indication that the wholesale prices in the UK correlate more closely to the prices of coal, gas and emission allowances than their German counterparts. The differences in the German and UK price formation mechanism point to the insufficient integration of these markets. We also show that the frequency at which high-price fuels become marginal increases in both countries. Given that demand did not increase significantly in the sample period, we interpret the finding as a leftward shift of the supply function, indicating a reduction in available, less costly production capacities. We provide indication that non-fuel-based coefficients can explain some of the electricity price increases observed. These findings are in line with conjectures that the initially strong link between short-term marginal cost and prices gradually vanishes due to decreasing generation margins or increasing exercise of market power. Although more research is needed, our new approach to modeling wholesale prices based on fuel and emission prices proves useful in understanding the nonlinear nature of electricity price formation.

II.6 Appendix

Table 9: Result of the ordinary least square model for the electricity price

	UK off-peak (R²=93%)		UK on-peak (R²=80%)		German off-peak (R²=73%)		German on-peak (R²=57%)	
	beta	std	beta	std	beta	std	beta	std
β_{const}	**3.26**	0.74	**4.43**	2.06	**5.05**	1.18	**20.35**	3.43
β_{coal}	**1.71**	0.13	0.61	0.35	**0.82**	0.19	**-2.51**	0.56
β_{gas}	**0.88**	0.02	**2.17**	0.05	**1.14**	0.05	**2.55**	0.15
β_{C02}	**0.82**	0.02	**0.93**	0.05	**0.57**	0.03	**1.14**	0.08
Bold coefficients are significantly different from zero.								

Table 10: Prior mean and starting values of the model with non-informative priors

	State 1	State 2	State 3
β_{const}	5	10	15
β_{coal}	1	1	1
β_{gas}	1	1	1
β_{C02}	1	1	1

Table 11: Prior mean (prior variance) and starting values of the model with informative priors

	off-peak			on-peak		
	Base	Coal	Natural Gas	Coal	Natural Gas	Spike
β_{const}	5 (10)	10 (10)	15 (10)	5 (10)	10 (10)	100 (10)
β_{coal}	0 (0.1)	3 (1)	0 (0.0001)	3 (1)	0 (0.0001)	0 (0. 1)
β_{gas}	0 (0.1)	0 (0.0001)	2 (1)	0 (0.0001)	2 (1)	0 (0. 1)
β_{C02}	0 (0.1)	1 (1)	1 (1)	1 (1)	1 (1)	0 (1)

Table 12: Jarque-Bera Test statistics for the normality of the residuals

	State 1	State 2	State 3
German on-peak	38.24^{**}	42.65^{*}	38.97^{**}
German off-peak	44.83^{**}	$0.49^{[]}$	74.73^{**}
UK on-peak	7.87^{**}	27.96^{*}	11.94^{**}
UK off-peak	11.89^{**}	$1.89^{[]}$	4.73^{**}
German on-peak (non-info. priors)	16.72^{**}	17.66^{**}	72.29^{*}
German off-peak (non-info. priors)	84.6^{**}	$1.18^{[]}$	53.17^{**}
UK on-peak (non-info. priors)	8.25^{**}	6.97^{**}	30.43^{**}
UK off-peak (non-info. priors)	16.35^{**}	$3.92^{[]}$	$2.81^{[]}$
$^{*}, ^{**}, ^{***}$ The null hypothesis of residuals normality can be rejected at the 10%, 5%, 1% significance levels. $^{[]}$ The null cannot be rejected at the 10% significance level.			

Table 13: Results of the switching regression for German on-peak

	freq	$\beta_{Constant}$	β_{Coal}	β_{Gas}	β_{CO2}	Mean
2002-2006 (R^2=80%)						
State1 (“Coal)	0.30	**7.4** (+/-4.6)	**2** (+/-0.92)	0 (+/-0.02)	**1.63** (+/-0.13)	33.42
State2 (“Gas”)	0.57	**14.7** (+/-3.5)	0 (+/-0.02)	**1.87** (+/-0.26)	**1.37** (+/-0.14)	44.64
State3 (“Spike”)	0.13	**91.9** (+/-6.1)	-.41 (+/-0.61)	-0.18 (+/-0.43)	**0.93** (+/-0.43)	97.05
2002-2004 (R^2=56%)						
State1 (“Coal)	0.24	**8** (+/-4.7)	**1.73** (+/-0.9)	0 (+/-0.02)	0 (+/-0)	16.92
State2 (“Gas”)	0.66	**13.1** (+/-3.5)	0 (+/-0.02)	**1.93** (+/-0.29)	0 (+/-0)	34.32
State3 (“Spike”)	0.10	**86.8** (+/-5.9)	-.59 (+/-0.62)	**-1.35** (+/-0.6)	0 (+/-0)	60.14
2005-2006 (R^2=71%)						
State1 (“Coal)	0.41	**7.4** (+/-5.2)	**3.79** (+/-1)	0 (+/-0.02)	**1.15** (+/-0.21)	51.53
State2 (“Gas”)	0.45	**15.4** (+/-5.4)	0 (+/-0.02)	**2.38** (+/-0.4)	**0.97** (+/-0.34)	73.98
State3 (“Spike”)	0.15	**101.5** (+/-6)	0.08 (+/-0.6)	0.24 (+/-0.42)	0.31 (+/-0.45)	119.97
2002-2006 non-informative priors (R^2=75%)						
State1	0.35	**12.5** (+/-7)	**-1.27** (+/-1.2)	**1.6** (+/-0.4)	**1.12** (+/-0.17)	34.96
State2	0.44	**18.8** (+/-5)	**-1.04** (+/-.69)	**2.06** (+/-0.29)	**1.32** (+/-0.12)	44.06
State3	0.22	**28.6** (+/-11)	2.41 (+/-3.09)	0.75 (+/-0.82)	**2.15** (+/-0.58)	77.93
(+/-) = Half of the two-sided 95% confidence interval width. Bold coefficients are significantly different from zero.						

Table 14: Results of the switching regression for German off-peak

	freq	$\beta_{Constant}$	β_{Coal}	β_{Gas}	β_{CO2}	Mean
2002-2006 (R^2=90%)						
State1 (“Base)	0.38	**6.8** (+/-2.9)	**1.11** (+/-0.43)	**0.35** (+/-0.28)	**0.76** (+/-0.13)	22.80
State2 (“Coal”)	0.34	**13.7** (+/-2.8)	**1.57** (+/-0.54)	0.01 (+/-0.02)	**0.94** (+/-0.16)	29.52
State3 (“Gas”)	0.28	**19.8** (+/-1.9)	0 (+/-0.02)	**0.71** (+/-0.13)	**0.94** (+/-0.11)	38.60
2002-2004 (R^2=75%)						
State1 (“Base)	0.42	**5.5** (+/-3.1)	**1.11** (+/-0.41)	**0.48** (+/-0.29)	0 (+/-0)	16.28
State2 (“Coal”)	0.29	**14.2** (+/-2.3)	**1.44** (+/-0.45)	0 (+/-0.02)	0 (+/-0)	22.14
State3 (“Gas”)	0.29	**17.8** (+/-3)	0 (+/-0.02)	**0.9** (+/-0.25)	0 (+/-0)	28.86
2005-2006 (R^2=78%)						
State1 (“Base)	0.39	**11.6** (+/-3.6)	**0.66** (+/-0.54)	**0.44** (+/-0.24)	**0.59** (+/-0.16)	33.72
State2 (“Coal”)	0.31	**13.6** (+/-3.8)	**2.51** (+/-0.77)	0 (+/-0.02)	**0.62** (+/-0.19)	39.31
State3 (“Gas”)	0.30	**19.8** (+/-5)	0 (+/-0.02)	**0.71** (+/-0.23)	**0.87** (+/-0.2)	51.72
2002-2006 non-informative priors (R^2=92%)						
State1	0.38	-1 (+/-4)	**2.02** (+/-0.62)	**0.6** (+/-0.14)	**0.66** (+/-0.07)	23.95
State2	0.40	3.4 (+/-3.5)	**1.63** (+/-0.59)	**0.96** (+/-0.1)	**0.66** (+/-0.06)	29.96
State3	0.21	**15.9** (+/-7.1)	-.03 (+/-1.28)	**1.11** (+/-0.27)	**0.82** (+/-0.15)	38.46
(+/-) = Half of the two-sided 95% confidence interval width. Bold coefficients are significantly different from zero.						

Table 15: Results of the switching regression for UK on-peak

	freq	$\beta_{Constant}$	β_{Coal}	β_{Gas}	β_{CO2}	Mean
2002-2006 (R^2=87%)						
State1 (“Coal)	0.37	**2.6** (+/-1.5)	**4.1** (+/-0.27)	0.01 (+/-0.02)	**1.19** (+/-0.07)	29.55
State2 (“Gas”)	0.53	**13.2** (+/-2.4)	0 (+/-0.02)	**1.79** (+/-0.2)	**0.87** (+/-0.12)	45.12
State3 (“Spike”)	0.10	**89.2** (+/-6.2)	-.59 (+/-0.63)	**0.98** (+/-0.3)	-0.3 (+/-0.45)	103.64
2002-2004 (R^2=67%)						
State1 (“Coal)	0.46	**2** (+/-1.6)	**4.2** (+/-0.28)	0 (+/-0.02)	0 (+/-0)	25.29
State2 (“Gas”)	0.51	**12.3** (+/-2.5)	0 (+/-0.02)	**1.81** (+/-0.23)	0 (+/-0)	32.19
State3 (“Spike”)	0.03	**90.7** (+/-6.9)	-.52 (+/-0.61)	**-0.89** (+/-0.68)	0 (+/-0)	65.99
2005-2006 (R^2=80%)						
State1 (“Coal)	0.22	**5.6** (+/-5.4)	**3.26** (+/-1.14)	0 (+/-0.02)	**1.86** (+/-0.53)	54.71
State2 (“Gas”)	0.61	**10.9** (+/-4.5)	0 (+/-0.02)	**2.36** (+/-0.42)	**0.38** (+/-0.35)	61.29
State3 (“Spike”)	0.17	**96.3** (+/-6.4)	-0.24 (+/-0.6)	**0.84** (+/-0.4)	-.38 (+/-0.55)	113.55
2002-2006 non-informative priors (R^2=90%)						
State1	0.47	**2.7** (+/-1.7)	**2.13** (+/-0.35)	**1.05** (+/-0.13)	**0.98** (+/-0.06)	29.95
State2	0.40	**10.6** (+/-5.1)	**1.47** (+/-0.81)	**1.42** (+/-0.24)	**0.91** (+/-0.14)	46.11
State3	0.13	**24.5** (+/-14)	1.29 (+/-2.91)	**1.85** (+/-0.26)	**0.8** (+/-0.44)	93.72
(+/-) = Half of the two-sided 95% confidence interval width. Bold coefficients are significantly different from zero.						

Table 16: Results of the switching regression for UK off-peak

	freq	$\beta_{Constant}$	β_{Coal}	β_{Gas}	β_{CO2}	Mean
2002-2006 (R^2=95%)						
State1 (“Base)	0.80	**4.3** (+/-0.9)	**1.59** (+/-0.17)	**0.82** (+/-0.09)	**0.77** (+/-0.03)	26.87
State2 (“Coal”)	0.11	**9.2** (+/-4.5)	**2.72** (+/-0.62)	0.01 (+/-0.02)	**1.08** (+/-0.17)	39.37
State3 (“Gas”)	0.09	**16.4** (+/-4)	0 (+/-0.02)	**0.83** (+/-0.14)	**0.87** (+/-0.28)	62.15
2002-2004 (R^2=84%)						
State1 (“Base)	0.81	**4.6** (+/-1.4)	**1.61** (+/-0.17)	**0.75** (+/-0.14)	0 (+/-0)	20.85
State2 (“Coal”)	0.05	**9.3** (+/-5)	**2.75** (+/-0.7)	0 (+/-0.02)	0 (+/-0)	29.36
State3 (“Gas”)	0.14	**17.1** (+/-6.1)	0 (+/-0.02)	**0.78** (+/-0.58)	0 (+/-0)	25.84
2005-2006 (R^2=85%)						
State1 (“Base)	0.56	**11.3** (+/-3)	0.34 (+/-0.46)	**0.81** (+/-0.16)	**0.88** (+/-0.06)	40.59
State2 (“Coal”)	0.21	**13.9** (+/-3.5)	**3.11** (+/-0.84)	0 (+/-0.02)	**0.45** (+/-0.17)	41.73
State3 (“Gas”)	0.23	**17** (+/-4)	0 (+/-0.02)	**0.81** (+/-0.15)	**0.81** (+/-0.29)	62.89
2002-2006 non-informative priors (R^2=94%)						
State1	0.63	**3** (+/-1.6)	**1.67** (+/-0.22)	**0.89** (+/-0.09)	**0.77** (+/-0.03)	28.92
State2	0.26	**6.2** (+/-2.7)	**2.38** (+/-0.4)	**0.27** (+/-0.14)	**1.16** (+/-0.06)	26.84
State3	0.11	**12.9** (+/-9.3)	0.84 (+/-1.53)	**0.82** (+/-0.14)	**0.78** (+/-0.23)	56.31
(+/-) = Half of the two-sided 95% confidence interval width. Bold coefficients are significantly different from zero.						

III Asymmetric Pass-Through of EU Emissions Allowance Prices to German Wholesale Electricity Prices

III.1 Introduction

This chapter provides the first application of the “rockets and feathers” literature on asymmetric cost pass-through between carbon dioxide (CO_2)-emission prices and wholesale electricity prices. The literature distinguishes between two variations of asymmetric pricing: In *short-term asymmetric pricing,* positive and negative cost shocks are diffused at speeds that differ from the product prices (“Rockets and Feathers”) but that lead to symmetric, long-term relations between prices and cost (timing effect). In *long-term asymmetric pricing,* a positive cost shock has a different long-term impact on final prices than a negative cost shock (magnitude effect).[66]

Asymmetric pricing has been intensively investigated in the input-to-output price pass-through literature, especially the link between oil and gasoline prices.[67] Other industrial and agricultural products as well as services (banking) also feature the same phenomenon.[68] Most empirical papers contend that positive cost shocks are disseminated more strongly and/or more rapidly to the final prices than negative cost shocks. These explanations posit either the exercise of market power or industry-specific factors. Bailey and Brorsen (1989, p.247) consider firms facing a (concave or convex) kinked demand curve that leads to (negative or positive) asymmetric pricing. Borenstein et al. (1997) suggest three hypotheses to explain their finding of *short-term asymmetric pricing* in the gasoline market: (1) a model of tacit collusion with imperfect monitoring,[69] (2) a model with finite inventories, and (3) a model of consumer search cost. Balke et al. (1998) consider oligopolistic firms that engage in tacit collusion to maintain higher profits where asymmetric pricing occurs as an effect of signaling: input price increases are instantaneously matched by output price increases to signal to competitors that collusion will be maintained. However, if input prices fall, firms will wait to lower output prices to avoid signaling an undermining of the unspoken agreement. Balke et al.

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[66] Note that by definition long-term asymmetric pricing implies the short-term version. This is evident as asymmetries in the long run can only occur if there are asymmetries in the short run.

[67] In this area a battery of tests has been proposed and applied. See Geweke (2004), Manera and Frey (2005) and Kaufmann and Laskowski (2005) for a survey of the asymmetric gasoline pricing literature.

[68] See Peltzman (2000).

[69] Borenstein et al. (1997) assume that the old gasoline prices offer a natural focal point for retailers if cost decreases (firms will maintain prices above the competitive level as long as their sales remain above a threshold level), while cost increases would immediately “squeeze” the margin and are therefore passed through to consumers.

(1998) show that accounting methods such as “first in first out” can lead to asymmetric pricing. Asymmetric menu cost could also induce asymmetric pricing.[70] As the mentioned industry specific explanations (search cost, menu cost, accounting of inventories) do not apply in electricity futures markets, the dissemination patterns of positive and negative cost shocks are an insightful indicator of the functioning and efficiency of markets.

Like gasoline prices, in the short-run electricity future prices are mainly driven by the volatile prices of its production inputs. Therefore, the presence of asymmetric cost pass-through in electricity future markets can be easily tested for different cost components. We are aware of anecdotal evidence that wholesale prices occasionally reacted more to EUA price increases than to decreases. For example, a 60% drop in EUA prices in the last week of April 2006 was only met by an 8% decline in power prices (EEX 2007 Futures). In this chapter we thus inquire the case of asymmetric cost pass-through of EUAs to electricity futures prices by applying the methodology from the aforementioned literature.

In 2003 the European Union issued the Directive on the implementation of a European Emission Trading System (EU ETS)[71] to fulfill its Kyoto commitment of reducing greenhouse gas emissions from 1990 to 2012 by 8%. This “cap and trading” schema started its mandatory three-year trial phase with the beginning of 2005. The basic idea is that emissions sources with low-cost reduction opportunities can over comply and sell their additional allowances to sources where reductions would be more costly. This leads to the lowest overall cost, or most economically efficient solution. In the first phase only CO_2 and a range of large installations in six key industrial sectors[72] are concerned while with the beginning of 2008 also other greenhouse gases and at a later stage also additional sectors (possibly transportation) will be affected. The overall cap in the emissions trading scheme is made up of individual country caps set by each nation’s national allocation plan (NAP). The annually emitted EUAs are mainly transferable within each phase (“banking”). Despite concerns from economists most EUAs were allocated for free to the emitting installations (“grandfathering”). Nevertheless, their usage undoubtedly represents (opportunity) cost for the polluter as each EUA used could

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[70] Cf. Meyer and Cramon-Taubadel (2004).

[71] Directive 2003/87/EC of October 13th 2003.

[72] The covered ~12,000 installations in these six sectors (electricity and heat production plants, oil refineries, coke ovens, metal ore and steel installations, cement kilns, glass manufacturing, ceramics manufacturing, and paper, pulp and board mills) currently make up for ~40% of the 25 EU countries CO_2 emissions.

not be sold at the market price. Therefore, it is not surprising to empirically find a positive link between EUA and power prices. Due to the different CO_2-intensities of electricity production technologies, the influence of EUA prices on power prices is nonlinear.[73] Using 2005 data, Sijm et al. (2006) estimated that emission costs have been almost fully (60-100%) passed through to consumers.

This chapter applies an error correction and an autoregressive distributed lag model to identify asymmetric cost pass-through in the relationship between EUA and wholesale electricity prices. We reject the hypothesis of symmetric cost pass-through in favor of asymmetric pricing. We hope that our investigations will stimulate a discussion of empirical evidence and theoretical explanations of this phenomenon.

III.2 Data

In 2005 a total of 350 m tones of CO_2 (worth around € 9 bn) were traded at the European Climate Exchange (London), various European electricity exchanges and OTC. This dissertation is mainly interested in the German market, and will therefore use the data provided by EEX. We opt to use data for the EUA spot market. We also obtained spot market electricity prices as well as prices for electricity futures with delivery in 2007 from EEX for the entire sample period (workdays of 2005-2006).[74]

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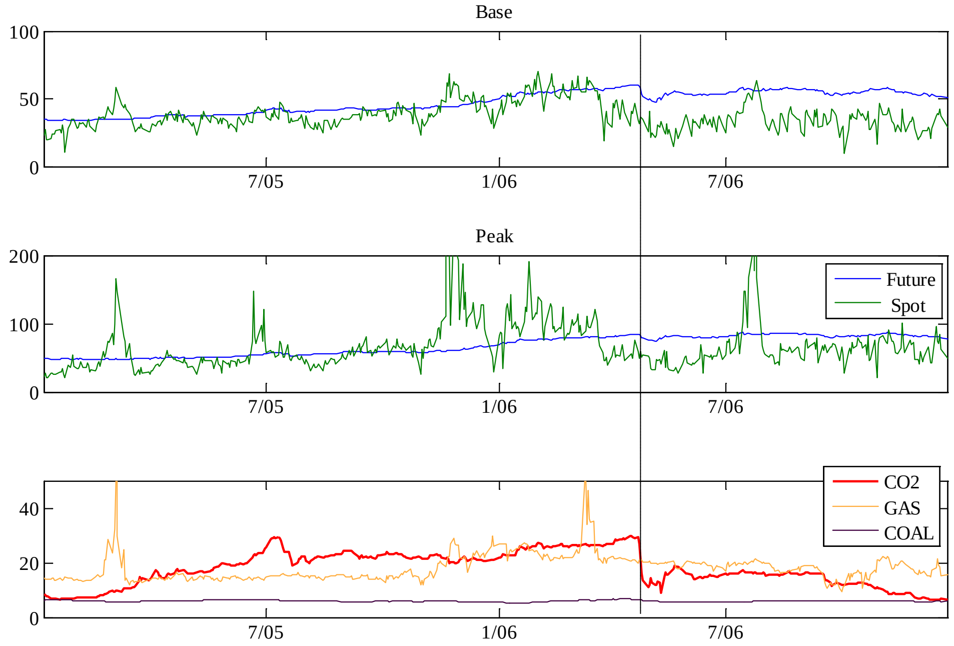
[73] The emergence of CO_2 as a cost factor in electricity prices complicates the analysis of the competitive supply curve (“merit order”). Fuels vary in emissions, e.g. nuclear (0 t/MWh), natural gas (0.48t/MWh) and coal (0.85t/MWh). Therefore, peak electricity prices (generally determined by a marginal combined cycle gas turbine) are likely to be less affected by CO_2 prices than mid-load electricity prices (generally coal). See Chapter II for the non-linear relation of electricity and EUA prices.

[74] EEX prices are often considered as reference and usually track the more liquid OTC prices sufficiently well.

Figure 5: Electricity future and spot prices and CO_2, coal and natural gas prices in 2005-2006 (in €/MWh)



The EEX EUA spot prices as well as EEX electricity futures and spot prices for the years 2005-2006 are depicted in Figure 5. The most outstanding event, the price crash in spring 2006,[75] is highlighted by the dashed vertical line. Electricity futures and spot prices differ significantly in almost all statistical measures (e.g. mean, variance). The higher volatility of electricity spot prices results from the fact that they are based on more volatile drivers (e.g. weather, demand, and plant availability) and that electricity future prices capture a longer delivery period, smoothing the effects on individual supply and demand shocks. Since hourly demand and supply factors are less important for price formation in electricity futures markets, the main drivers are fuel and EUA prices. This is illustrated by the significantly higher correlation of EUA price changes with electricity futures than with electricity spot price changes. Daily EUA price changes feature no significant correlation with spot electricity price changes, but a correlation coefficient of .72*** with base electricity future 2007 price changes. Because of this structure, we limit our analysis to the EEX futures prices.

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[75] At the end of April 2006, information leaked to traders that some countries (Netherlands, Czech Republic, Walloon, Spain, France) emitted significantly less CO_2 than expected. This created an overall long position in the market, causing EUA prices to drop from around €30 to €10. For details see CEAG (2006).

III.3 Methodology and Results

(a) Error Correction Model

Following Borenstein et al. (1997), we estimate the asymmetric diffusion pattern of positive and negative cost shocks using Error Correction Models (ECM).[76] These models assume a long-term (symmetric) relation between prices and cost

$$EEX_t = \phi_0 + \phi_1 TIME_t + \phi_2 X_t + \phi_3 CO2_t \tag{1}$$

but allow for short-term systematic deviations:

$$\begin{aligned} \Delta EEX_t &= \sum_{i=0}^{n}\left(\beta_i^+ \Delta CO2_{t-i}^+ + \beta_i^- \Delta CO2_{t-i}^-\right) + \sum_{i=0}^{n}\left(\lambda_i \Delta GAS_{t-i}\right) + \sum_{i=1}^{n}\left(\gamma_i \Delta EEX_{t-i}\right) \\ &+ \theta EEX_{t-1} - \theta\phi_0 - \theta\phi_1 TIME_{t-1} - \theta\phi_2 GAS_{t-1} - \theta\phi_3 CO2_{t-1} + \varepsilon_t \end{aligned} \tag{2}$$

where EEX_t is the electricity price, $CO2_t$ the EUA price, GAS_t the natural gas price and $TIME_t$ a linear time vector in time t. The period-to-period change in the electricity price is denoted by ΔEEX_t, $\Delta CO2_t^+$ is the positive period-to-period EUA price change (or zero if $\Delta CO2_t < 0$), $\Delta CO2_t^-$ the negative period-to-period EUA price change (or zero if $\Delta CO2_t < 0$) and ΔGAS_t is the period-to-period natural gas price change. Furthermore, ε_t is an independent and identically-distributed error term. The coefficients $\beta_i^+, \beta_i^-, \lambda_i, \theta, \theta\phi_0, \theta\phi_2$ and $\theta\phi_3$ can be estimated using ordinary least squares. The idea of (2) is that changes in the electricity price are driven by changes in past electricity prices, current and past changes in EUA and natural gas prices as well as the error correction term that tends to bring the electricity price back to its long run equilibrium (if $\theta < 0$). That is, if the electricity price in t-1 was above its equilibrium value, i.e., $EEX_{t-1} - \phi_0 - \phi_1 TIME_{t-1} - \phi_2 GAS_{t-1} - \phi_3 CO2_{t-1} > 0$, the current change in electricity prices (ΔEEX_t) should be smaller than indicated by the input price changes, bringing the electricity price closer to its equilibrium.

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[76] For details on the Error Correction Model see for example Greene (2002, p.654ff).

To reduce the number of variables (and because of a lack of significance), we delete the asymmetric reaction to past electricity prices suggested by Borenstein et al. (1997). The response of the electricity price in time $t + k$ to a one-time, 1%-positive CO_2 price shock in t is according to Borenstein et al. (1997, p.337) given by

$$B_k^+ = B_{k-1}^+ + \hat{\beta}_k^+ + \theta\left(B_{k-1}^+ - \hat{\phi}_1\right) + \sum_{i=1}^{k}\left(\hat{\gamma}_i \left(B_{k-i}^+ - B_{k-i-1}^+\right)\right). \qquad (3)$$

Because our sample length is limited (2 years), only a few specific combinations of lag length and data-frequency can be reasonably considered. Thus, we estimate equation (2) separately for weekly average base and peak futures prices using four lags in both cases. To control for gas price developments, we include Dutch TTF gas spot prices since there is no comparably liquid corresponding German market.[77]

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[77] Since including time trend, constant, coal prices or load as well as controlling for the market crash in April 2006 do not alter the asymmetry results significantly, we only present the results for the most parsimonious specification. Detailed results may be obtained from the author upon request.

Table 17: Error correction model results

Variable	Base	Peak
R2 ($\overline{R}^2$)	74% (69%)	63% (54%)
σ^2	0.48	0.86
Durbin-Watson	1.92	1.94
Engels ARCH[78] (CV 5%=3.84)	3.17	2.05
Kolmogorov-Smirnov (CV 5%=0.13)	0.09	0.08
$\theta\phi_0$ (Constant)	1.33	1.17
$\theta\phi_1$ (Time Trend)	0.02 **	0.03 **
β_0^+ (dCO2+t)	0.14	0.09
β_1^+ (dCO2+t-1)	0.15	0.07
β_2^+ (dCO2+t-2)	-0.17	-0.29 *
β_3^+ (dCO2+t-3)	0.49 ***	0.70 ***
β_0^- (dCO2-t)	0.02	0.05
β_1^- (dCO2-t-1)	-0.17 *	-0.19 ***
β_2^- (dCO2-t-2)	0.17 *	0.11
β_3^- (dCO2-t-3)	0.52 ***	0.42 ***
γ_1 (dEEX$_{t-1}$)	-0.01	0.04
γ_2 (dEEX$_{t-2}$)	-0.04	-0.09
γ_3 (dEEX$_{t-3}$)	0.10	0.16
λ_0 (dGAS$_t$)	-0.03	-0.03
λ_1 (dGAS$_{t-1}$)	0.00	0.01
λ_2 (dGAS$_{t-2}$)	0.02	0.02
λ_3 (dGAS$_{t-3}$)	0.06 **	0.08 **
θ (EEX$_{t-1}$)	-0.09 **	-0.07 **
$\theta\phi_2$ (CO2$_{t-1}$)	0.05 *	0.07 *
$\theta\phi_3$ (GAS$_{t-1}$)	0.04 ***	0.04 **
F(H$_0$: CO2$_{sym}$ vs. H$_1$: CO2$_{asym}$)	2.9 **	1.9
*,**,*** Coefficient different from zero on the 10%, 5%, 1% confidence intervals respectively. Weekly average 2005-2006 data (99 observations).		

The R^2 above 60% and the Durbin-Watson statistic of almost 2 indicate that our model is reasonably well specified.[79] Theta (θ) is significantly negative indicating that error correction cannot be rejected. In the base and the peak cases, we find the typical characteristic of positive asymmetric cost pass-through: while in the first two weeks, positive EUA price

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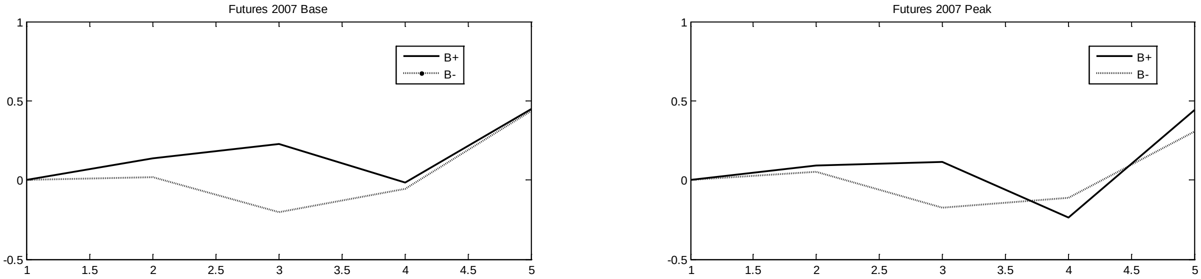
[78] ARCH: AutoRegressive Conditionally Heteroscedastic Model (for details see: Greene (2002, p.216ff)).

[79] Note that including coal prices and electricity demand as explanatory variables does not prove significant. The residual tests (Kolmogorov-Smirnov cannot reject normality; Engels ARCH can reject conditional heteroscedasticity) cannot reject normality.

shocks have a stronger positive influence on EEX prices, negative shocks (i.e. EUA price decreases) catch up in the third and fourth weeks ($\hat{\beta}_t^+ > \hat{\beta}_t^-$ and $\hat{\beta}_{t-1}^+ < \hat{\beta}_{t-1}^-$). The B^+ and B^- values calculated according to (3) confirm the quicker pass-through of positive EUA price shocks to electricity future prices (see Figure 7). While the null hypothesis of symmetric cost pass-through cannot be rejected for the peak case, it can be rejected on the 5% confidence level for the base case. The latter is evidence for positive asymmetric cost pass-through.

One additional finding merits notice. The last lag of the asymmetric coefficient is in all cases high (~0.5) and highly significant unlike most other lags. This indicates that the imposed error correction forces our model back to the equilibrium in the last period. Although it may be possible to detect additional dynamics by including more lags, this is infeasible because the ratio of variables over observations is already critical.[80]

Figure 6: Impact of EUA price changes on electricity price changes estimated using an ECM and data from the German electricity and emissions markets 2005-2007



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[80] The number of variables equal $(3+x)\times n+3$, where x is the number of exogenous variables and n is the number of lags. This is critical since the data sample consists of only two years and correspondingly only 104-n weekly observations are available.

(b) Autoregressive Distributed Lag Model

A way to circumvent the difficulties of the ECM is by omitting the error correction term, thus deviating from the idea of a long-term equilibrium. By doing so, the forced upward trend in the last lag and the number of estimated coefficients can be greatly reduced.[81] Following Karrenbrock (1991) our autoregressive distributed lag (ADL) model is:

$$\Delta EEX_t = \phi_0 + \phi_1 t + \sum_{i=0}^{n}\left(\beta_i^+ \Delta CO2_{t-i}^+ + \beta_i^- \Delta CO2_{t-i}^-\right) + \sum_{i=0}^{p}\left(\gamma_i \Delta X_{t-i}\right) + \varepsilon_t \qquad (4)$$

In (4), we can test the hull hypothesis of symmetric cost pass-through against the alternative hypothesis of asymmetric cost pass-through by finding whether $\beta_i^+ = \beta_i^-$ for all i.

Table 18: Autoregressive distributed lag model results

Variable	Base	Peak
R^2 ($\overline{R}^2$)	71% (67%)	52% (46%)
σ^2	0.5	1.0
Durbin-Watson	1.47	1.33
Engels ARCH (CV 5%=3.84)	2.61	0.10
Kolmogorov-Smirnov (CV 5%=0.13)	0.07	0.09
$dCO2^+_t$	0.18 *	0.18
$dCO2^+_{t-1}$	0.13	-0.01
$dCO2^+_{t-2}$	-0.09	-0.14
$dCO2^+_{t-3}$	0.52 ***	0.76 ***
$dCO2^-_t$	-0.04	0.03
$dCO2^-_{t-1}$	-0.19 ***	-0.23 **
$dCO2^-_{t-2}$	0.22 ***	0.17 *
$dCO2^-_{t-3}$	0.51 ***	0.38 ***
$\sum dCO2^+$	**0.74**	**0.79**
$\sum dCO2^-$	**0.50**	**0.35**
$dGAS_t$	-0.01	0.00
$dGAS_{t-1}$	0.03	0.04
$dGAS_{t-2}$	0.01	0.01
$dGAS_{t-3}$	0.04 *	0.06 *
F(H_0: $CO2_{sym}$ vs. H_1: $CO2_{asym}$)	**4.1 *****	**3.4 ****
*,**,*** Coefficient different from zero on the 10%, 5%, 1% confidence intervals respectively. Weekly average 2005-2006 data (99 observations).		

Therefore, we estimate (4) using a specification comparable to the presented ECM. The ADL model results indicate a slightly inferior fit compared to the ECM in terms of adjusted R^2 and

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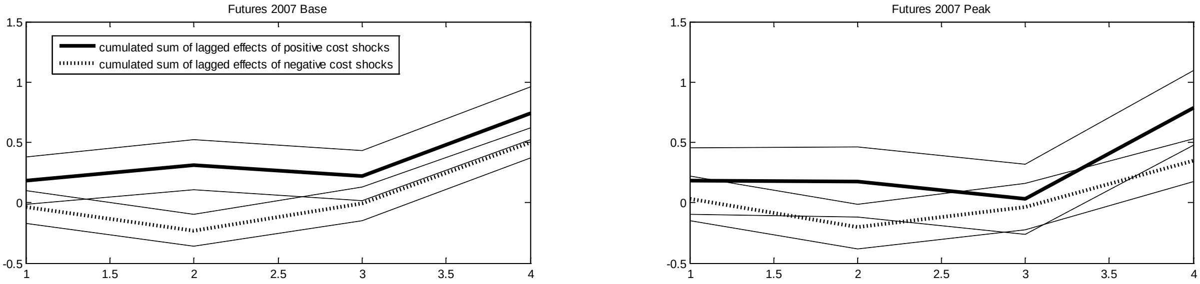
[81] Note that Geweke (2004) criticizes (4) since it implies the gap between prices and cost will grow indefinitely in the long-term. In our case, however, this argument does not hold because the length of our sample does not allow the prices to return sufficiently often to the long-term equilibrium.

Durbin-Watson statistics. Nevertheless, the results in Table 18 provide strong evidence for positive asymmetric cost pass-through of EUA prices. The accumulated sums of the lagged coefficients for positive EUA price changes in both cases are larger than those for negative ones (see Figure 7). Further, we can reject the hypothesis of EUA symmetric cost pass-through to electricity futures prices in favor of the asymmetric version on the 5% confidence level. Moreover, assuming asymmetric gas price pass-through does not prove significant in general,[82] this is evidence that asymmetric pricing is not a universal phenomenon in electricity futures markets but is specific to the EUA price pass-through.

Figure 7: Cost Pass-through of EUAs in base and peak future 2007 prices 2005-2006



III.4 Conclusions

This chapter analyzes asymmetric cost pass-through between EUA and electricity future prices in Germany by applying error correction and ADL models. We find convincing evidence that emission prices are passed through asymmetrically to electricity futures prices in Germany.

We observe that since most industry-specific explanations for asymmetric pricing (search cost, inventories, menu cost, signaling, and the like) do not apply for wholesale electricity markets, two intuitive explanations arise, although neither is fully convincing. First, asymmetric cost pass-through may be a sign of an early market phase, where knowledge and expertise about handling a newly introduced cost factor develop over time. Second, finding evidence of asymmetric pricing may indicate the exercise of market power by German generators.

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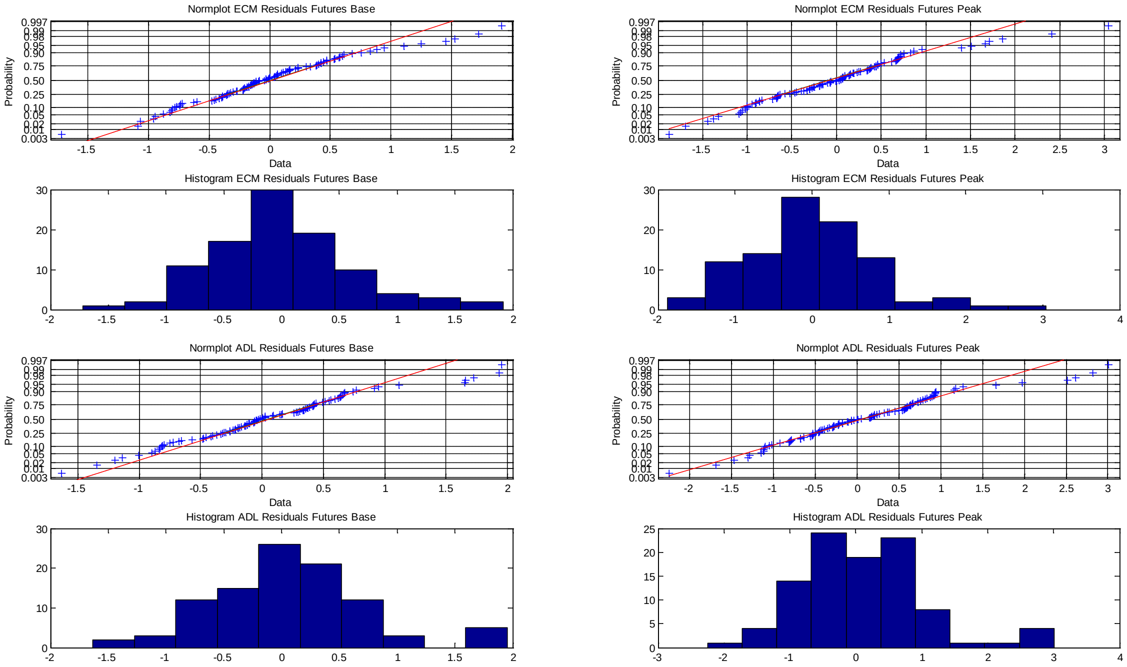
[82] See Table 19 in the Appendix to this chapter.

III.5 Appendix

Figure 8: Residual tests


Normplot ECM Residuals Futures Base

Normplot ECM Residuals Futures Peak

Histogram ECM Residuals Futures Base

Histogram ECM Residuals Futures Peak

Normplot ADL Residuals Futures Base

Normplot ADL Residuals Futures Peak

Histogram ADL Residuals Futures Base

Histogram ADL Residuals Futures Peak

Table 19: F-Test for asymmetric cost pass-through in the ADL model

	Future Base	Future Peak
F(H0: $CO2_{sym}$ vs. H1: $CO2_{asym}$) given GAS_{asym}	4.1^{***}	2.9^{**}
F(H0: GAS_{sym} vs. H1: GAS_{asym}) given $CO2_{asym}$	1.8	1.9
F(H0: $CO2\&GAS_{sym}$ vs. H1: $CO2\&GAS_{asym}$)	3.0^{***}	2.7^{**}
F(H0: $CO2_{sym}$ vs. H1: $CO2_{asym}$) given GAS_{sym}	4.1^{***}	3.4^{**}
F(H0: GAS_{sym} vs. H1: GAS_{asym}) given $CO2_{sym}$	1.7	2.3^{*}

IV Electricity Wholesale Market Prices in Europe: Convergence?

IV.1 Introduction

This chapter looks at the development of a single electricity market in Europe. We pay particular attention to cross-border trade via explicit transmission capacity auctions, which allows us to identify inefficiencies in international electricity trade.

A common electricity market is expected to increase welfare by ensuring security of supply, stimulating competition, and reaping the gains from international cooperation through such means as reserve sharing, combining different national consumption and production patterns, etc. To create a single European market, the EU has issued two directives, one regulation and several decisions that oblige both old and new member states to undertake substantial reform efforts. The measures require that: markets be opened (e.g. Directive 2003/54/EC); obstacles to cross-border trade be reduced (Regulation 1228/2003); and that non-discriminatory third-party access to the network be guaranteed (e.g. Directive 2003/54/EC). To date, implementation (via the enactment of national laws) among the member states varies. Even a cursory read of the reports benchmarking national electricity sector reforms such as EC (2005), EC (2006), and OXERA (2005) reveals the differences that remain. Although there has been substantial progress by some members, the EU’s ultimate goal is yet far off.

Given these circumstances, several authors wonder whether market outcomes can confirm the success of the reforms with respect to the EU’s common market policy. Bower (2002), Armstrong and Galli (2003, 2005), Boisseleau (2004), and Turvey (2006) compare day-ahead wholesale market prices at several European power exchanges. Bower (2002) applies correlation and cointegration analysis to 2001 prices from the Nordic countries, Germany, Spain, the UK, and the Netherlands. He concludes that some European electricity markets (especially the Nordic countries, the Netherlands, and its neighbors) were already integrated to a certain extent by 2001.[83] A relevant chapter in Boisseleau (2004) that focuses on regression and correlation analysis determines that the level of integration of European markets is quite low. Both Bower (2002) and Boisseleau (2004) describe the respective status

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[83] However, this result is mainly due to Bower’s use of unweighted daily average data; given the strong differences between peak and off-peak price behavior in the market, it is an inappropriate representation of price data.

quo of European market integration; in contrast, Armstrong and Galli (2005) analyze the evolution of price differentials in France, Germany, the Netherlands and Spain from 2002 to 2004, and conclude that European electricity prices converge in this period.[84] Turvey (2006) examines the use of interconnectors and the pricing of scarce transmission capacities. Based on the example of the Anglo-French Interconnector, he provides empirical indication for the insufficient correlation of flows and price differentials.

International electricity price convergence[85] can be triggered by different factors, such as the convergence of factor prices; the convergence of product prices[86]; the harmonization of the institutional framework; the convergence of electricity market regulation; the convergence of production technologies and consumption patterns; and increasing international electricity trade. While changing investment behavior as well as mergers and acquisitions will primarily have long-term impacts, the growth of international trade will promote market integration in the short- and medium-term. This chapter concentrates on the latter. We test whether European day-ahead wholesale prices converged between 2002 and 2006. Showing that national prices approach convergence over time would indicate that the single market policy was effective in the medium-term, and finding no convergence would imply the (at least initial) shortcomings of those policies.

We distinguish between the *level of market integration:* the (static) degree to which the single European market is attained; and *price convergence:* the (dynamic) measure for the development of prices toward a single European price. Unlike the empirical studies mentioned above, this chapter accounts for the effects of congestion and congestion management by

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[84] Their reasoning is based on the comparison of three yearly averages of price differentials. Because Armstrong and Galli (2003, 2005) did not perform statistical tests on the significance of their results and ignored the cross-border capacity rationing mechanisms, it remains uncertain whether their conclusions can be generalized.

[85] The term “convergence” follows the definition used by Engel and Rogers (2004), i.e. price convergence is the reduction of international price level dispersion over time. Thus, neither increasing correlation of the price series nor a reduction in the volatility of the international price differences are sufficient conditions for assuming convergence. By contrast, a significant reduction in the systematic price difference between two markets implies convergence.

[86] The Heckscher-Ohlin model, for example, predicts that factor (i.e., electricity) prices converge when product prices converge.

including the prices in the daily auctions for the use of scarce transmission capacities (so-called “congestion charges” [87]).

To capture both market integration and price convergence, our line of argument consists of three steps. First, we demonstrate by means of PCA that no single European electricity market exists to date. Second, using stationarity tests, we show that several price pairs converged bilaterally in 2002-2006. Third, we provide evidence that congestion, as represented by the hourly cross-border capacity auction prices, cannot fully explain the insufficient electricity market integration observed.

IV.2 Data

Workable, wholesale electricity markets are a cornerstone of the EU’s desire to build a single market. Thus, most of the old and some of the new EU member states have established power exchanges in recent years. Nearly all feature a spot market on which electricity for each hour of the day ahead is traded. We use their “on the hour” prices to examine intraday developments and compare them across markets.

Our dataset consists of information from six West European countries (Austria; France; Germany; Netherlands; Spain; and the UK); two new Central European EU member states (Poland; Czech Republic)[88]; and three North European price areas (East Denmark; West Denmark; and Sweden). The sample covers the years 2002 to 2006. This limitation to less

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[87] Since administrative “congestion charges” no longer exist in the West- and Central European Union for the Co-ordination of Transmission of Electricity (UCTE), we use the term as a synonym for the prices paid in cross-border capacity auctions.

[88] We focus on the two largest electricity producers in this region: Poland and the Czech Republic. A detailed description of their respective electricity market design and structure appears in Hirschhausen and Zachmann (2006). In brief, the competitive situation in both countries is rather disappointing. The Czech generation sector is characterized by a quasi-monopolist (CEZ) that uses its rents to acquire stakes in generation and distribution companies all across Eastern Europe. The Polish wholesale market, although quite decentralized at the moment, shows strong tendencies towards an oligopoly of three integrated coal and power plant companies. For the time being, the impediment to a functioning Polish wholesale market is the remaining long-term contracts between electricity generators and the TSO. The wholesale markets in both countries are only beginning to emerge. Absent an ordinary electricity exchange, the Czech market operator OTE organizes an electricity spot market in the Czech Republic. Though it provides prices for almost all hours of the year, the liquidity is still low. The Polish Power Exchange (PPX) also suffers from low trading volumes. These can be explained by existing long-term contracts and the inadequate balancing and reserve market design that renders efficient electricity trade rather difficult (Toczyłowski (2005)). The low liquidity of the Polish market is, however, in contrast to the almost total absence of outliers in the price series. As a result of the relatively high volumes traded at the EEX, the German prices act as reference prices for the entire region.

than five years results from the insufficient liquidity in most of the considered markets before 2002. Nevertheless, the significant changes in the market framework during this period (e.g., Directive 2003/54/EC, Regulation 1228/2003), and the high data frequency available should reveal the systematic developments of market integration.

Table 20 summarizes the domestic electricity consumption, electricity traded on the spot market and the resulting spot market liquidity in 2005 for the eleven points (and their abbreviations). Since participation in most of the wholesale spot markets is considered voluntary, their liquidity represents a relatively small fraction of domestic consumption; this is especially true for the Polish, Czech, Austrian and British day-ahead prices.[89]

Apart from the UKPX, the markets feature uniform price, sealed bid, one-shot day-ahead electricity auctions. The auctioneer collects all supply and demand bids and orders them into 24 hourly bid collections. Market clearing is done once per trading day and separately for each hour; physical delivery of the electricity sold is taken on the following day. Despite minor differences in structure, liquidity, products and market mechanisms, the power exchanges in Austria (EXAA), France (Powernext - PNX), Germany (EEX), the Netherlands (APX), and Poland (PPX) operate in similar fashion. The Nordic countries (Denmark; Finland; Norway; and Sweden) have a common power exchange called NordPool which organizes a joint spot market (Elspot). The Spanish power exchange (OMEL) is a mandatory pool leading to a comparably high liquidity. With its low liquidity of 0.6 % (2005), the Czech market (OTE) is not a typical power exchange but we include it in our dataset because it provides the only available data on hourly day-ahead prices from this major exporting country. Finally, the UKPX features a continuous trading period of 48 hours that closes only a half hour ahead of delivery.

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[89] We note that the liquidity of some electricity exchanges is quite low. Absent equally consistent data, the spot prices are usually considered as the national reference price. The economic reasoning is that if the “real” price were essentially different from the power exchange price, arbitrageurs would be inclined to buy on the cheaper and sell on the more expensive markets without any risk of forcing the prices to converge.

Table 20: Liquidity of European power exchanges

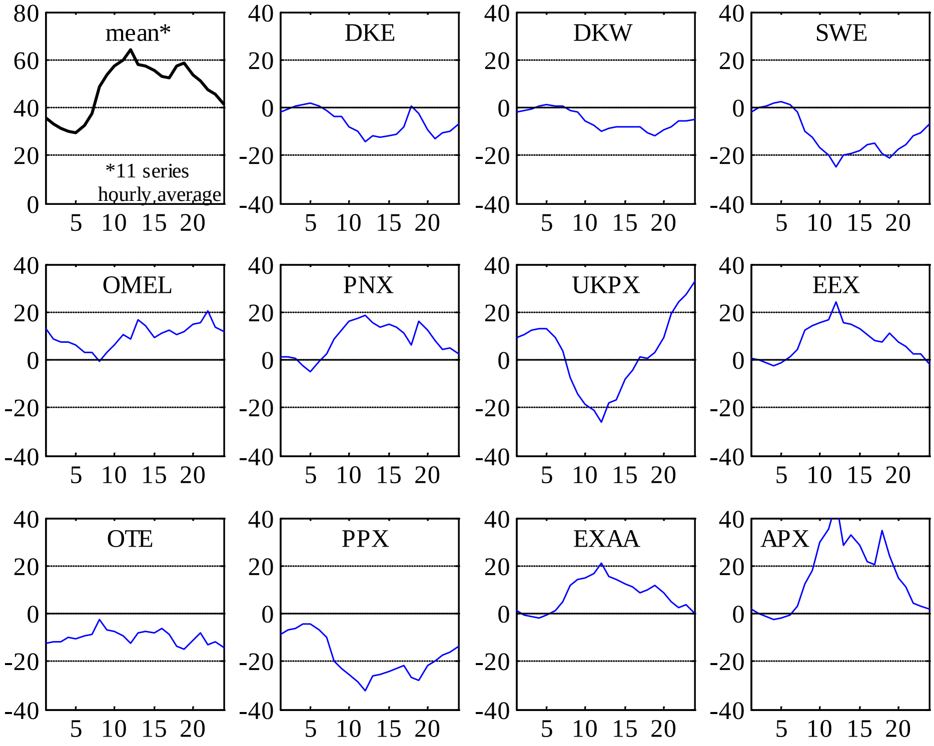
Abbreviation – Power Exchange (Country)	Currency	Spot Market Volume 2005 in TWh	Total Consumption 2005 in TWh	Share of Power Traded Spot
APX – Amsterdam Power Exchange (NL)	€	16.0	114.7	14%
EEX – European Energy Exchange, Leipzig (D)	€	85.3	556.4	15%
EXAA - Energy Exchange Austria, Graz (A)	€	1.5	63.2	2%
DKE – East Danish NordPool price area (DK)	DK	NordPool Total: 167.8	Nordel Total: 402.7	42%
DKW –West Danish NordPool price area (DK)	DK			
SWE – Swedish NordPool price area (S)	SK			
PNX – Powernext, Paris (F)	€	19.7	482.4	4%
PPX – Polish Power Exchange, Warsaw (POL)	Zt	2.0	130.6	2%
UKPX – UK Power Exchange, London (UK)	£	8.8	407.3	2%
OMEL - Operador del Mercado Ibérico de Energía, Madrid (ES)	€	223.3	252.8	88%
OTE – Czech Market Operator, Prague (CZ)	CZK	0.4	62.7	1%
Sources: *Consumption*: websites of the Organisation for the Nordic Transmission System Operator [www.nordel.org], the Union for the Co-ordination of Transmission of Electricity [www.ucte.org] and the UK Department of Trade and Industry (now UK Department for Business, Enterprise & Regulatory Reform) [www.berr.gov.uk/energy/statistics]; *Spot Volumes*: websites of the respective power exchanges				

IV.3 Methodology and Results

(a) No Full Market Integration

Figure 9 depicts the average differences of each price series from the common mean price series. Obviously, no unit-price, single European market exists as average price differences are significant and in the extreme attain levels of more than 60€/MWh (e.g. SWE-APX 13h). Whereas some markets are constantly above (OMEL) or below (OTE, PPX) the European average price, others encounter quite different price patterns. EEX, EXAA, APX and PNX are significantly more expensive than the average during on-peak hours (8h-20h), while DKE, SWE, PPX and UKPX are below average in these hours. Only DKW approximately matches the European average. The resemblance of the French (PNX), the Austrian (EXAA) and the German (EEX) price profile points to some regional clustering of electricity markets.

Figure 9: Hourly average of eleven European electricity price series (upper left) as well as the individual deviation from the common mean (all other) January 2005-July 2006 (in €/MWh)[90]



We can use PCA to reveal the regional price interactions.[91] The underlying idea is to calculate the linear combinations of the original data matrix that explain most of the variance. Our data matrix consists of the weekday price series for the eleven wholesale markets. The PCA is carried out separately only for a typical off-peak (3h) and a typical on-peak hour (13h).[92] To give an impression of the development of the European electricity market integration over time, we subdivide the sample into March 2002 to June 2004 and June 2004 to July 2006. We calculate the first and second principal component for the normalized data, and compute the correlation between the principal components and the original data.[93] This allows visualizing the clustering of the markets by plotting the correlation coefficient of each price series with the first principal component on the X-axis and with the second principal component on the Y-axis. Figure 10 indicates that the eleven wholesale markets can be roughly divided into two

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[90] The mean price at the APX at the 12th hour, not represented in the figure to make the eleven other figures better readable and have a common scale, is 46.95.

[91] See footnote 52.

[92] Plotting the results for all 24 hours of the day provides little value added, as 2:00-3:00 (3h) and 12:00-13:00 (13h) mark boundary cases essentially enveloping all other hour of the day patterns.

[93] Detailed results may be obtained from the author upon request.

regional groups: the Austrian (EXAA), Dutch (APX), German (EEX) and French (PNX) market and the East Danish (DKE), West Danish (DKW) and Swedish (SWE) market. The British (UKPX), Spanish (OMEL), Czech (OTE) and Polish (PPX) markets cannot be clearly attributed to either group.

Figure 10 also presents the percentage of variance explained by the first PC (the first principal component with which almost all series are positively correlated can be interpreted as a common European electricity price development). As τ_1 (the variance explained by the first PC[94]) is significantly below 100% in all considered cases it is thus evident that full market integration has not been achieved. The significant increase of τ_1 from the early (2002-2004) to the more recent (2004-2006) period both for the on-peak (31% → 52%) and off-peak (40% → 63%), however, implies that at least some individual series approach the common European pattern. Another interesting finding is that prices are better explained by the first principal component during off-peak. One explanation may be that networks are less utilized in low-consumption off-peak hours, leading to lower cross-border congestion and thus allowing for more international trade.

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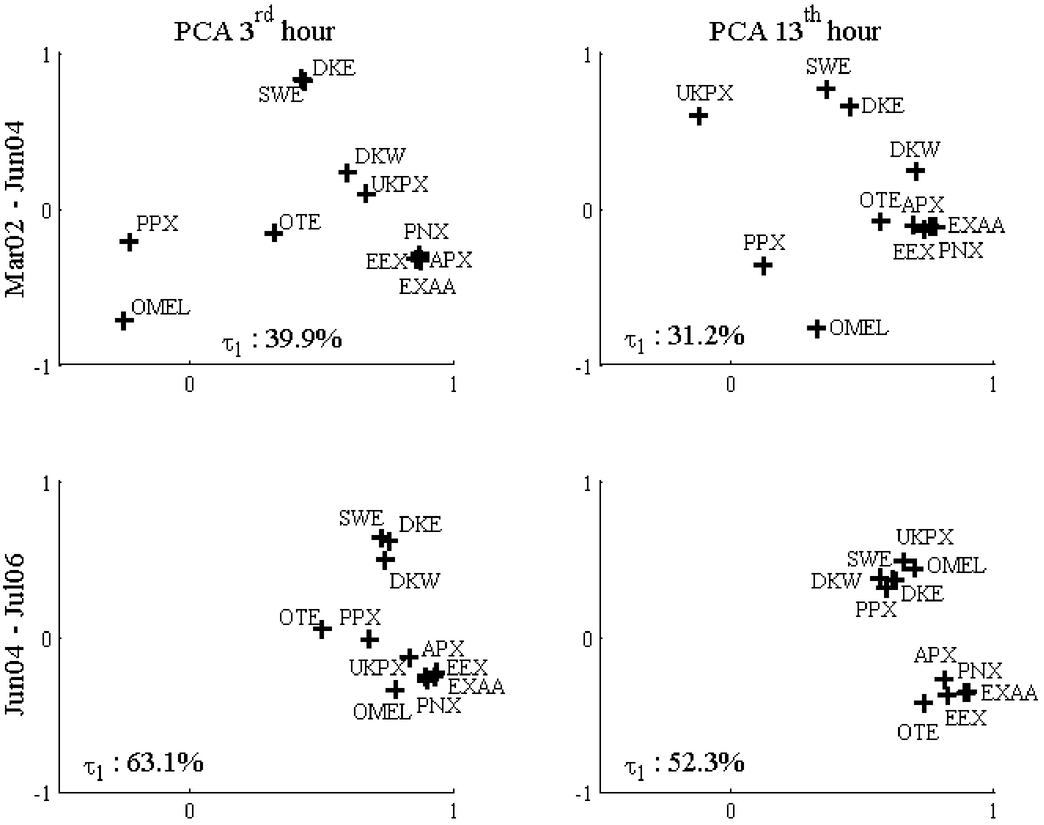
[94] The variance explained by the i^{th} principal component is calculated according to $\tau_i = \lambda_i \Big/ \sum_{j=1}^{p} \lambda_j$, where λ_i is the i^{th} largest eigenvalue (see footnote 52).

Figure 10: Correlation of the 3rd and 13th hour wholesale spot prices with their first (X-axis) and second (Y-axis) principal component as well as variance explained by the first (τ_1) principal component



(b) Signs of Convergence

PCA provides some indication that a common European price pattern is increasingly able to explain national price developments.[95] The concept of "convergence" allows studying the intensification of integration for each pair of countries separately. Following the empirical literature (e.g. St. Aubyn (1999) or Bernard and Durlauf (1996)) one method to assess regional convergence is by testing if the difference of the two regional series contains no unit root, i.e. if the series are cointegrated with the cointegration vector $\beta = [-1,1]$[96]. According to this approach, bilateral electricity market convergence implies that the difference in the logarithm of national electricity spot prices is stationary.[97] By applying the ADF[98] and the

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[95] Note that PCA cannot be used to explicitly demonstrate convergence as the increased ability of the first PC to explain the variance of the data is potentially due to the significant and largely exogenous electricity price increases throughout Europe in 2004-2006. Thus, the increase in the first PC is not sufficient to demonstrate convergence as defined in FN 85.

[96] Note that the interaction of wholesale electricity prices has already been studied using cointegration analysis, e.g. by De Vany and Walls (1999).

[97] i.e. According to the definition in Hamilton (1994, p.45) $\mathrm{Var}\left(\log\left(p^i\right)-\log\left(p^j\right)\right)_t = \sigma < \infty$ and $\mathrm{E}\left(\log\left(p^i\right)-\log\left(p^j\right)\right)_t = \mu$ for all t.

KPSS[99] tests, the combination permits us to test jointly for divergence and convergence since the ADF test is based upon the null hypothesis of a unit root (i.e. rejection suggests convergence) and the KPSS test is based upon the null hypothesis of stationarity (i.e. rejection suggests divergence).

The ADF test is specified according to Case 1 in Hamilton (1994, p.528), i.e. without trend and constant. In other words, we want the price differences to collapse to zero and not to some constant. Thus, the one percent critical value for long series is -2.58. The lag length is selected according to Ng and Perron (1995).[100] The KPSS test is specified without time trend, leading to a one percent critical value of 0.74. The window length is specified according to Smith and Otero (2005).[101]

Table 21: Pair wise stationarity (+) or unit root (-) of base electricity price differential 2002-2006 according to KPSS and ADF tests

	DKW	SWE	OMEL	PNX	UKPX	EEX	OTE	PPX	EXAA	APX	#
DKE	++	+	+		-		+	--	-	-	4
DKW			+		-		+	--	-		3
SWE			+		-				-	-	2
OMEL							++	-		+	5
PNX						+	+	--	++		3
UKPX								--	-	--	0
EEX							++	--	++	+	4
OTE									+	++	7
PPX									--	--	0
EXAA										+	4
APX											4

\+ : ADF rejects unit root at the 1% level and KPSS accepts stationarity at the 1% level => Convergence
++ : ADF rejects unit root at the 1% level and KPSS accepts stationarity at the 5% level => Convergence
\- : ADF accepts unit root at the 1% level and KPSS rejects stationarity at the 1% level => Divergence
-- : ADF accepts unit root at the 5% level and KPSS rejects stationarity at the 1% level => Divergence
: All other cases (including reject both and accept both) => Undecidable

Using the setup described, we test for pair wise convergence of prices. Table 21 presents the results for daily average electricity prices.[102] We find that 18 pairs of prices converge, 18 diverge and 19 are insignificant – an indication that European electricity market integration

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[98] ADF: Augmented Dickey Fuller test, for details see Dickey and Fuller (1979).

[99] KPSS: for details see Kwiatkowski, Phillips, Schmidt and Shin (1992).

[100] Starting at pmax = integer[12*(T/100)^1/4], we want to find out if the absolute value of the t-statistic of the last lagged difference is >1.6. If yes, we perform the unit root test; otherwise, we reduce p by one and repeat the process.

[101] Window length l = integer[12*(T/100)^1/4]. Note that the choice of the ADF lag length and the KPSS window length are crucial as the number of rejections decrease significantly with an increase in both measures.

[102] Note that testing stationarity separately for peak hours produces almost identical results.

has not been a universal process (if it did occur, it was on a pair wise basis only). In fact, the outcomes provide indication that convergence is predominantly driven by bilateral cross-border market integration. Whereas almost half of the prices of the directly linked markets converge (7/16), only one-quarter of the none-linked markets show significant convergence (11/39). Moreover, nine of these eleven none-linked but converging market pairs include either the Czech (5) and/or the Spanish (5) markets. We posit that convergence of the Czech price series is probably driven by increasing liquidity which forces the OTE price to approach the "real" Czech price (which is linked to the European price via the German EEX prices). It is less obvious why the Spanish (OMEL) prices approach the Nordic (DKE, DKW, and SWE) as well as the Dutch (APX) prices.

Using unit root tests for testing convergence is not universally accepted[103] for at least three reasons. First, stationarity of the price differential can imply both full market integration and price convergence, making it impossible to distinguish whether two markets are still converging or have already integrated. Second, in situations where mean price convergence is associated with increasing volatility, the stationarity test can erroneously reject the convergence hypothesis. This is relevant to our analysis because electricity prices and thus the volatility of the difference series increased significantly in the past several years.[104] Third, in the presence of mean and variance "jumps" as well as outliers, unit root tests lack robustness. Therefore, we design an alternative approach.

The two simple indicators for the integration of two markets are the difference of the prices in both countries and the ratio of the prices. We choose the logged ratio since it can be interpreted as the relative deviation from full integration. The gross integration measure is calculated according to

$$\gamma_{gross,t}^{i,j} = \log\left({p_t^i}\Big/{p_t^j} \right) = \log\left(p_t^i\right) - \log\left(p_t^j\right).$$

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[103] See for example Bernard and Durlauf (1995, 1996) and St. Aubyn (1999).

[104] Increasing volatility of the difference series is insufficient for demonstrating the absence of convergence (as defined in FN 85) because the level of two series might approach even though the volatility of the difference series increases. In fact, the difference series of two perfectly parallel price series has zero volatility, while this volatility increases, if the price series start to converge.

Thus, full integration is achieved if $\gamma_{gross,t}^{i,j} = 0$ for all *t*. The integration indicator is noisy and characterized by many significant outliers because of the high volatility of hourly prices. To extract the long-term development of market integration, we filter out idiosyncratic and short-term developments. Time-varying coefficient models provide an adequate framework

$$\begin{aligned} \gamma_{gross,t}^{i,j} &= \alpha_t + \varepsilon_t \\ \alpha_t &= \beta\alpha_{t-1} + \upsilon_t \end{aligned} \qquad (1)$$

where $\varepsilon_t \sim N(0,\sigma_\varepsilon^2)$ and $\upsilon_t \sim N(0,\sigma_\upsilon^2)$ are *iid* error terms and α_t is the vector of unobservable coefficients at time *t*.

Through filtering out short-term shocks (ε_t) the estimated $\hat{\alpha}_t$ represents the long-term pattern of integration.[105] To estimate $\hat{\alpha}_t$, we must make assumptions about the initial variances of ε_t, υ_t and α_0 as well as on the expected value of α_0 and β. Setting $E(\alpha_0) = \gamma_1$ and $E(\beta) = 1$ is straightforward but setting the variances is less so.[106] Visual inspection suggests that $\sigma_\upsilon^2 = Var(\gamma_t)/100$, $\sigma_\varepsilon^2 = Var(\gamma_t)$ and $\sigma_{\alpha_0}^2 = 10$ will provide an acceptable compromise in noise reduction and signal preservation. We can assure stable estimates by performing the filter and smoother algorithm up to five times using the estimated coefficients and variances as inputs for the subsequent run.

We estimate equation (7) separately for each hour of the weekday series for the German-Czech, German-Polish, German-Dutch, German-East Danish, German-West Danish, German-French, Polish-Czech and French-Spanish borders. Consequently, we obtain 192 smoothed

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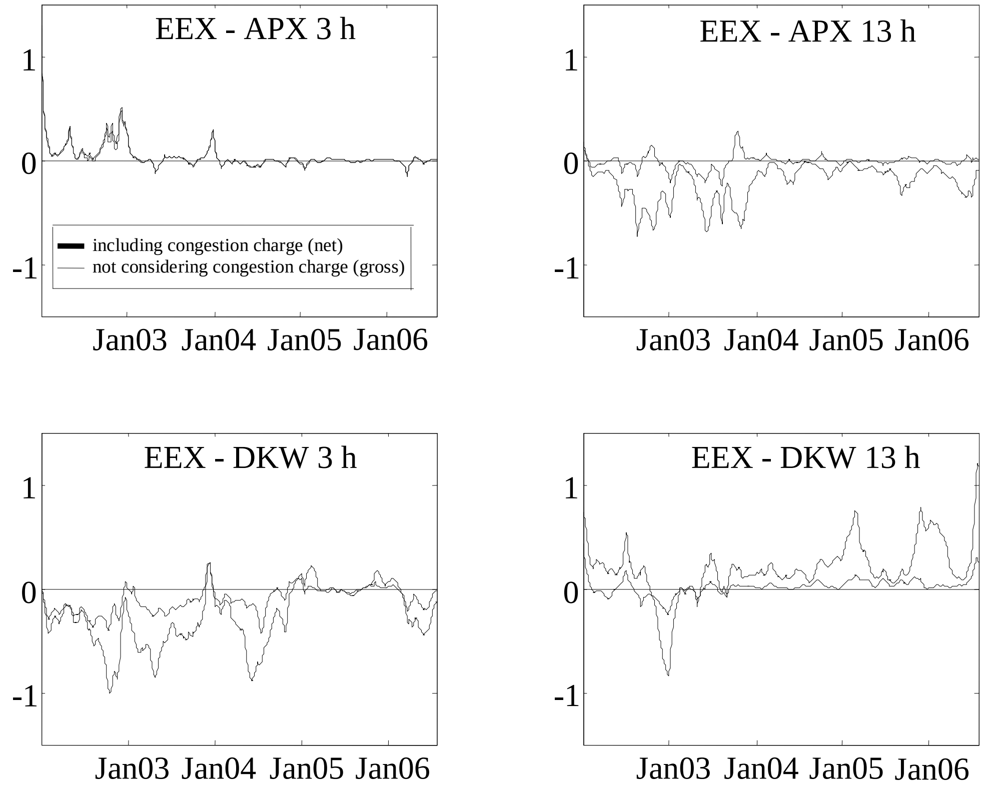
[105] As described in Hamilton (1994, p.399ff), time-varying coefficient models such as (1) are estimated using the Kalman filter and smoother. We use the Matlab Kalman filter toolbox by Kevin Murphy, 1998 [see http://www.ai.mit.edu/~murphyk/Software/kalman.html].

[106] Generally, we can interpret the initial variances as the starting point of the search for the global extrema of the likelihood function. Therefore, if the function has several local maxima, a “wrong” starting point can lead to undesirable results. This is why the initial variances should be carefully selected. The trade-off can be described as follows: using too-high values for σ_υ^2 and $\sigma_{\alpha_0}^2$ would lead to the inclusion of short-term behavior in α_t which would make it difficult to distinguish idiosyncratic shocks from systematic patterns. On the other hand, setting a low variance for υ_t would ignore significant developments in the convergence process.

integration indicator series. Figure 3 (darker line) shows the third and thirteenth hour series for the German-Dutch and the German-West Danish borders.[107]

Figure 11: Smoothed integration indicator $\hat{\alpha}_t$ for the EEX-APX and EEX-DKW borders for the 3rd and 13th hour series



We can now use the smoothed integration indicator α_t to test whether the two prices converge/diverge, and by regressing $\hat{\alpha}_t^{\,2}$ on constant (δ_1) and time trend ($\delta_2 t$) we can test increases/decreases in market integration. As the error terms (ξ_t) in $\hat{\alpha}_t^{\,2} = \delta_1 + \delta_2 t + \xi_t$ are not normally independently distributed, the usual t-statistics do not apply for testing the null hypotheses that δ_1 and/or δ_2 will not be zero. Therefore, we bootstrap the table of critical values, and estimate $\hat{\delta}_1$ and $\hat{\delta}_2$ for 1,000 randomly reordered series of $\gamma^{i,j}_{gross,T} = \left(\gamma^{i,j}_{gross,1}, \gamma^{i,j}_{gross,2}, \ldots, \gamma^{i,j}_{gross,n}\right)$.[108]

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[107] The results for all studied country combinations and hourly series may be obtained from the author upon request.

[108] The task is arduous since it must be performed separately for all studied pairs of countries as well as for all hours (192 series) to capture the statistical features of each series of $\gamma^{i,j}_{gross,T}$.

Now that we know the critical value, we can test for pair wise long-term price convergence/divergence. Theoretically, full market integration is achieved if all $\gamma^{i,j}_{gross,T}$ are indistinguishable from zero. We assume full integration of market i and j if no $\left|\gamma^{i,j}_{gross,t}\right|$ is larger than a half standard deviation of the (more volatile) underlying log electricity price series. Following this notion, we observe that the German-French market integrates in the sample period for four hours (1h, 2h, 10h and 17h). The integration of the two biggest Continental wholesale markets in two off-peak and two shoulder hours (between on-peak and off-peak) confirms the strong correlation of both markets that we already obtained using PCA.

Convergence towards full integration is assumed if we can reject both the null hypotheses $\delta_1 \leq 0$ and $\delta_2 \geq 0$. The results summarized in Table 22 reveal that while the gross price differentials between France and Spain and between Germany and the Netherlands decrease in all hourly series, gross convergence in the Polish-Czech, German-Czech, German-Polish and both German-Danish cases is primarily an off-peak period phenomenon. Our computations demonstrate that 113 of the 192 hourly pairs of price series converge between 2002 and 2006 (revealing that the degree of market integration generally increased during this period of active market development[109]). However, we also note that more than a third of the price series pairs do not converge. This finding should raise doubts about the effectiveness of the market reforms.

If we can reject both the null hypotheses $\hat{\delta}_1 \leq 0$ and $\hat{\delta}_2 \leq 0$, the price series diverges pair wise; we find this to be true for 48 of the 192 series.[110] In fact, almost all of the German-East Danish, German-West Danish and German-Polish on-peak price series diverge significantly. The higher frequency of gross convergence in off-peak (72 vs. 41) and divergence in on-peak (12 vs. 36) is explained by the scarcity of transmission capacity, i.e., when congestion and

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[109] The obvious volatility of the convergence process (see Figure 11) does not permit us to conclude that the observed convergence occurs at constant speed or will be non-reversible.

[110] Consequently, 27 series showed no significant signs of convergence or divergence, or attained full integration.

gross price differentials are more distinctive in high-load periods. The effect abates when we include congestion charges (see next section).[111]

Table 22: Number of hours of the day in which the price series significantly (5%) converges/diverges when not correcting for hourly congestion charges (gross)

	Load Period	PPX-OTE	EEX-OTE	EEX-PPX	EEX-PNX	EEX-APX	EEX-DKE	EEX-DKW	PNX-OME	Σ
Integration					4					**4**
Convergence $\Sigma = 114$	off-peak	10	8	7	5	12	10	9	11	**72**
	on-peak	5	4		8	12			12	**41**
Divergence $\Sigma = 48$	off-peak			5	2		2	3		**12**
	on-peak			12	1		11	12		**36**

IV.4 Including Congestion Charges

Despite the study period's very active international trading, the results of both the PCA and stationarity tests indicate that European market integration is far from completion.[112] The persistence of international price differentials is often justified by the scarcity of cross-border transmission capacities. Capacity allocation (also termed "congestion management methods") varies throughout the Continent occasionally changing in the most recent years (see Table 23). The dynamic is illustrated at the German-Czech-Polish border where in recent years, improvements in congestion management were undertaken in four steps: *First*, unilateral explicit auctions were introduced between Poland and the Czech Republic (since August 2002 on the CEPS[113] side) as well as between Germany and Poland/Czech Republic (on the E.on Netz / VE-T side). *Second*, bilateral auctions were organized by CEPS, VE-T and E.on Netz between Germany and Poland/Czech Republic in 2003. In both described stages, only yearly and monthly capacity bands were auctioned. In a *third* step, daily capacity auctions were introduced between Germany and the Czech Republic in 2004. Whereas the

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[111] Comparing the sums of hourly series converging ignores the reality that adjacent hourly series are highly correlated.

[112] Market integration can be triggered by the following: (1) an adjustment of factor prices, e.g. fuel prices, emissions cost, interest rates and wages; (2) the adaptation of a common institutional framework, e.g. emissions trading scheme, pollution prevention legislation, taxes or safety standards; (3) the convergence of electricity market regulation; (4) common production and consumption patterns, e.g. due to shared weather phenomena, resource endowments or fuel supplies; and (5) international electricity trade. The latter can prompt full market integration independent of the other causes.

[113] The TSOs are Vattenfall Europe Transmission (VE-T) and E.on Netz for Germany, PSE-Operator (PSE) for Poland and CEPS for the Czech Republic.

aforementioned monthly and yearly capacities between Germany and the Czech Republic were divided between E.on Netz and VE-T and auctioned by their administrator[114], CEPS carried out the daily auctions. The situation in 2004 which was characterized by bilateral daily/monthly and yearly auctions between E.on Netz/VE-T and CEPS as well as unilateral auctions of Polish-Czech congestions proved unsatisfactory. The problems included the lack of a Polish-German auction and the absence of coordination of the transmission capacities in the highly meshed German-Czech-Polish triangle.[115] To resolve these issues, a *fourth* step was taken when coordinated auctions between VE-T, PSE and CEPS were introduced in 2005. Yearly and monthly auctions were implemented at the beginning of the year, and daily auctions, selling single hour capacity bands, in April.[116] In particular, the coordinated daily auctions should have increased arbitrage significantly since price differences and thus the shadow prices of the bottlenecks vary greatly during the day.[117]

Table 23: Cross-border congestion management method in the sample period January 2002-August 2006

	DKW	SWE	EEX	UKPX	OMEL	APX	PPX	EXAA
DKE	IA	IA	<2005 EA >2005 IA					
DKW		IA	EA					
PNX			<2005 NMB >2006 EA	EA (only base)	<2005 NMB			
EEX		AL (Merchant line)				EA	<2005 EA* >2005 CEA	NMB (no congestion)
OTE			<2005 EA >2005 CEA				<2005 EA* >2005 CEA	<2005 EA* >2005 EA

EA: Explicit Auction; **EA***: Explicit Auction without day-ahead auctions;
AL: Access Limitation; **CEA**: Coordinated Explicit Auction (Poland; Czech Republic; Germany);
IA: Implicit Auction; **NMB**: Non-Market-Based (e.g. pro rata; priority list)
The table roughly summarizes ETSO (2004, p.5-7) and ETSO (2006, p.7-10) where more detailed information can be found.

In *implicit auctions* the market operator collects bids and offers for electricity deliveries in several regions and calculates regional prices accounting for any line limitations. If the transmission capacity between two areas becomes binding, the prices in both regions will differ. Consequently the congestion charge equals the price differential. In *explicit auctions* market participants can buy and sell electricity in all regional markets but must always ensure

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[114] CEPS obtained a fixed share of the revenues.

[115] In the COMECON period, the high-voltage system of the GDR, CSSR, Poland and other COMECON members was jointly operated by the Central Dispatch Organization of the Interconnected Power Systems (CDO/IPS) in Prague (Lagendijk (2005)).

[116] Data on the monthly and yearly auctions are available at http://www.e-trace.biz and for the daily auctions at http://market.ceps.cz/uc17.asp

[117] KEMA (2005), EFET (2004) and ETSO (2004).

that they acquire the requisite number of transmission rights. The rights are usually allocated in annual, monthly and daily auctions separately for each flow direction. Thus, if transmission demand exceeds line capacity we would expect the capacity auction price to be above zero and electricity prices in the linked markets to differ by exactly the auction price; otherwise, traders could make risk-free profits.[118]

We collected the results of the day-ahead cross-border capacity rights auctions for eight intra-European borders (France-Spain; Germany- Netherlands; Germany-Poland; Germany-Czech Republic; Germany-France; Germany-West Denmark; Germany-East Denmark; and Poland-Czech Republic). These auctions provide separate prices for both directions for all 24 hours of the subsequent day. Since the hourly congestion charges are based on approximately the same set of available information as the corresponding electricity spot prices, our analytical comparison is simple.

We construct a net integration measure by subtracting the congestion charges in the profitable direction ($c_t^{j->i}$ or $c_t^{i->j}$) from the more expensive price

$$\gamma_{net,t}^{i,j} = \begin{cases} \log\left(p_t^i - c_t^{j->i}\right) - \log\left(p_t^j\right) & \text{if} \quad p_t^i > p_t^j \\ \log\left(p_t^i\right) - \log\left(p_t^j - c_t^{i->j}\right) & \text{if} \quad p_t^i < p_t^j \end{cases}$$

We can interpret this indicator as the remaining arbitrage possibility from either undertaking a cross-border trade at date *t* if the auction price is below the international price differential, or rejecting a cross-border trade if the auction price is above it. In reality, the arbitrage freeness condition $\gamma_{net,t}^{i,j} = 0 \ \ \forall t$ can be fulfilled in implicit auctions since $c_t^{j->i} = \max\left(p_t^i - p_t^j, 0\right)$ holds by definition. In explicit cross-border capacity auctions where the markets operate sequentially, players face uncertainties in the capacity offered, the congestion charges and the price differentials. Because of the uncertainties in timing, $\gamma_{net,t}^{i,j} \neq 0$ does not necessarily imply an unused arbitrage possibility in time *t* since players may be surprised by unpredicted price changes. Therefore, unused arbitrage possibilities can only be assumed if $E\left(\gamma_{net,t}^{i,j}\right) \neq 0$. In this context the Kalman filter and smoother (see Section 3(b)) contains an especially useful

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[118] This arbitrage freeness assumes that traders will not spend more for transporting electricity than they can gain from it (i.e. the price differential), and that underpaying cross-border capacity auctions (i.e. price differential > congestion charge) is unsustainable since the potential gain (price differential minus congestion charge) will attract other players to enter the market, forcing the prices to converge toward arbitrage freeness.

interpretation: the filtered results can be seen as the expected realization of the underlying series in *t+1* given the series up to point *t*, while the smoother provides the expected realization of the underlying series given the entire series. Stochastic deviations due to accidental prediction errors can be decomposed from systematic deviations. Thus, if the smoothed $\gamma_{net,t}^{i,j}$ differs significantly from zero, it indicates that the price difference in *t* is expected to differ from zero (contradicting the assumption of arbitrage freeness). Applying the same testing procedure used for the gross price differential series ($\gamma_{gross,t}^{i,j}$) to the net price differential series ($\gamma_{net,t}^{i,j}$) allows us to analyze the development of unused arbitrage possibilities over time. Joint plotting of $\hat{\alpha}_{net,t}$ (the thin line in Figure 11) and $\hat{\alpha}_{gross,t}$ (heavy line) provides visual indication that hourly congestion charges often account for only a minor fraction of the gross price differential. This is proof that congestion is not solely responsible for insufficient market integration.

Visual inspection of the smoothed net integration indicators reveals that only a few series show systematic arbitrage freeness (the thin line in Figure 11). Nevertheless, some of the smoothed series approach arbitrage freeness (e.g. EEX-DKW 3 in Figure 11). We also observe that gradual adjustments characterize the process of convergence, an indication that continual developments in cumulative liquidity, an increasing number of traders and perpetual learning improve net market integration.[119] Hence, market reforms only gradually translate into more market integration.

Applying the same testing strategy used for the gross price differential, we find that only 12 of the 192 series show full integration and that the price series of five markets converge in the majority of hours. We can also identify significant trends of net divergence in three markets (Table 24). Thus, despite the possibility of arbitrage, more than 93% of the markets fail to integrate and nearly 40% of the price series never converge.[120] Such findings provide empirical indication that there are significant barriers to efficient cross-border trade when capacities are auctioned explicitly.

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[119] Neuhoff (2003) argues that traders learn to handle explicit auctions. He finds that while in 2001 a simple trading strategy would have generated € 30.6 m profits at the Dutch-German border in the first six months of 2002, only € 1.2 m were possible.

[120] The 40% stems from 76 neither integrated nor converging series (28 series diverging and 48 series without trend).

Table 24: Number of hours of the day in which the price series significantly (5%) converge/diverge when correcting for hourly congestion charges (net)

	Load Period	PPX-OTE	EEX-OTE	EEX-PPX	EEX-PNX	EEX-APX	EEX-DKE	EEX-DKW	PNX-OME	Σ
Integration				1	11					**12**
Convergence Σ =105	off-peak	6	9	8	2	11	12	11	2	**61**
	on-peak		11	1		9	8	11	4	**44**
Divergence Σ =28	off-peak	1		3	2				1	**8**
	on-peak	7		4	3		2		4	**20**

The demonstrated inadequacy of explicit auctions to provide long-term arbitrage freeness has been assumed both in the political discussion and the theoretical literature. Ehrenmann and Smeers (2005) for example point out that explicit auctions will produce results inferior to those of implicit actions because of the uncertainties for traders and the different network aggregation mechanisms. In fact, trader uncertainties may be responsible for some of the detected distortions. Although the Kalman filter algorithm filtered out stochastic distortions, the uncertainties also should have led to the inclusion of a risk premium in the studied price relations.[121] An indication of the importance of a risk premium is that divergence is slightly more present in on-peak than in off-peak while convergence is more frequent in off-peak. This finding correlates with the hypothesis that traders desire and expect a higher risk premium for the more volatile on-peak-time trading periods. Finally, it has been argued that market players may bid strategically in explicit auctions.[122]

The assumed shortcomings of explicit auctions have given rise to alternative congestion management methods. Proposals for continental Europe include establishing conventional systems like nodal pricing[123] and implicit auctions as well as extending the recently implemented open-market coupling for the French-Belgium-Dutch market.[124]

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[121] A risk premium for traders should reward the market participants for bearing the described uncertainties of participating in explicit capacity auctions. Neuhoff (2003, p.4) describes this risk premium as an insurance: "traders price their buy bid in one market very high and their offer in the other market very low to avoid exposure to imbalance fees if only one bid is accepted."

[122] See for example Neuhoff (2003), Brunekreeft et al. (2005, p.85) and Chapter V in this thesis.

[123] See for example Hogan (1992).

[124] A comparison of congestion management methods appears in Ehrenmann and Smeers (2005) and CONSENTEC (2004).

IV.5 Conclusions and Policy Implications

This chapter provides empirical evidence that a single market for electricity in continental Europe had not been attained by mid-2006. PCA reveals that from June 2004 to July 2006, 48% of the on-peak and 37% of the off-peak price variances cannot be explained by the first PC which can be interpreted as a common European price pattern.

We demonstrate that national electricity price differences significantly diminish over time for some market pairs. Stationarity tests of wholesale price differentials indicate that price convergence is mainly driven by cross-border market integration. Studying the convergence hypothesis for smoothed hourly price differential series allows us to trace medium-term patterns as well as intra-daily differences. We find that 59% of the studied hourly pairs of national wholesale electricity prices in 2002-2006 converge. This increased market integration is mainly an off-peak phenomenon. While 64% of the converging series are in off-peak, 75% of the diverging series occur in on-peak.

We also test the hypothesis that all remaining international price differences can be explained by cross-border transmission capacity auction prices. Arbitrage freeness is assured if the difference between cross-border price differentials and the associated transmission capacity prices is zero in expectation. We find that more than 93% of the studied market pairs feature significant predictable arbitrage opportunities, but that 42% do not converge towards arbitrage freeness.

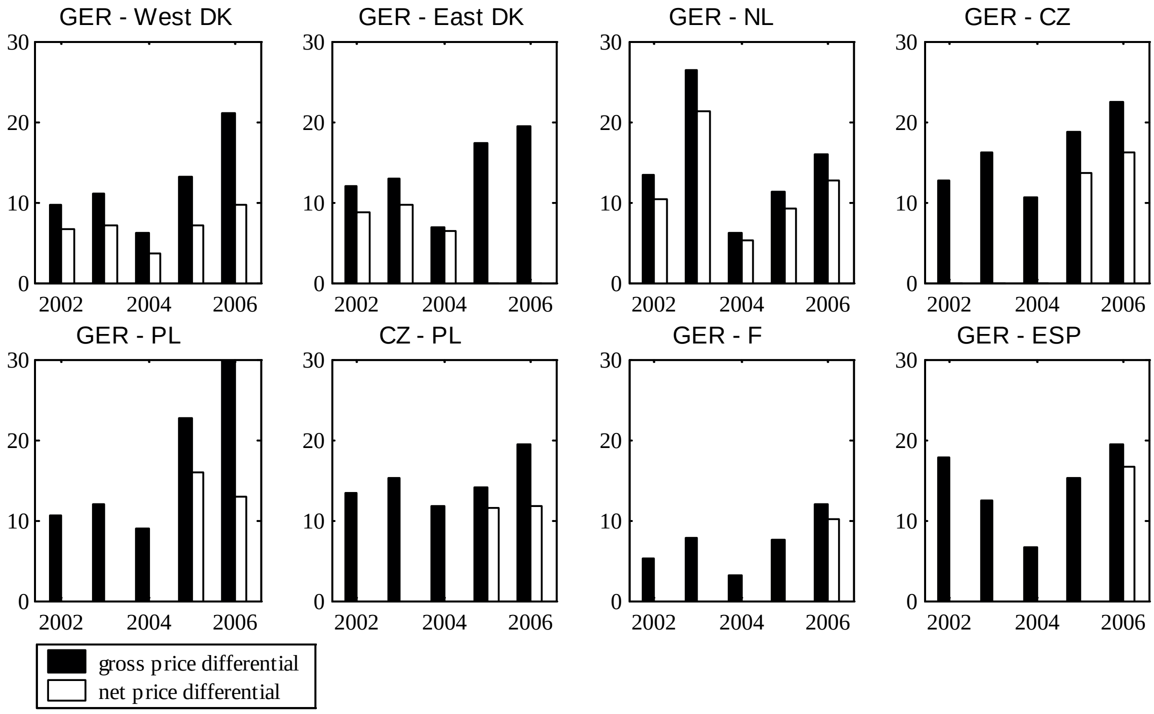
Our findings reveal that the market reforms undertaken in the last decade that explicitly targeted the creation of a single European market were only partially successful. We suggest that future research should include identifying the reasons for the inefficiencies of explicit auctions, such as risk premiums for traders and the exercise of market power. We believe that policymakers should be made aware of these and other potential obstacles to the gradual realization of their goal.

IV.6 Appendix

Table 25: Variance of the electricity price data matrix explained by the first (τ_1) and the second (τ_2) principal component

	March 2002 - June 2004		June 2004 - July 2006	
	3h	13h	3h	13h
τ1	40%	31%	63%	52%
τ2	22%	20%	13%	14%

Figure 12: Annual averages of the absolute hourly price differentials 2002-2006 (in €/MWh)



1) Where no net price differential is given, there were either no explicit auctions (e.g. GER - F before 2006) or no data available (e.g. GER - PL 2004).
2) In the figure, the absolute net price differentials, i.e. abs(price differential – congestion charge) are plotted. Therefore, the high remaining net price differentials do not generally indicate that daily explicit auctions are underpaid.
3) The year 2006 only contains data prior to August.

Table 26: First normalized principal component of European electricity prices

	Mar2002-Jun2004 3rd hour	Mar2002-Jun2004 13th hour	Jun2004-Jul2006 3rd hour	Jun2004-Jul2006 13th hour
DKE	0.42	0.37	0.29	0.34
DKW	0.42	0.42	0.28	0.37
SWE	-0.11	0.07	0.28	0.27
OMEL	0.15	0.30	0.29	0.30
PNX	0.41	0.41	0.34	0.34
UKPX	0.32	-0.06	0.32	0.29
EEX	0.41	0.39	0.34	0.37
OTE	-0.12	0.17	0.19	0.26
PPX	0.20	0.20	0.26	0.25
EXAA	0.28	0.38	0.35	0.23
APX	0.21	0.24	0.35	0.26

Table 27: Probability of convergence as well as the estimated intercept for each hourly series of the smoothed pair wise gross and net price relations

		Gross-Series		Net-Series			Gross-Series		Net-Series	
Series		Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$	Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$		Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$	Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$
PPX-OTE	**1**	3.75	100	0.25	80.9	**13**	0.17	90.6	0.01	20.8
PPX-OTE	**2**	4.2	100	0.63	99.6	**14**	0.16	93.6	0.01	1.5
PPX-OTE	**3**	4.59	100	1.41	100	**15**	0.42	100	0.04	24.4
PPX-OTE	**4**	7.93	100	1.35	99.9	**16**	1.15	100	0.03	1.9
PPX-OTE	**5**	10.15	100	2.01	100	**17**	0.68	100	0.01	0.2
PPX-OTE	**6**	4.34	100	1.41	100	**18**	1.35	100	0	2.3
PPX-OTE	**7**	0.87	51.6	0.53	99	**19**	2.95	100	0	1.9
PPX-OTE	**8**	0.12	3.3	0.07	94.7	**20**	2.25	100	0.01	57.4
PPX-OTE	**9**	0.34	42.8	0.01	2.5	**21**	0.22	99.7	0.03	93.7
PPX-OTE	**10**	0.2	8.9	0	0.4	**22**	1.21	96.7	0.04	1.1
PPX-OTE	**11**	0.25	94.3	-0.01	0	**23**	1.52	100	0.02	83.7
PPX-OTE	**12**	0.23	9.1	0.02	5.1	**24**	3.42	100	0.09	52.4
EEX-OTE	**1**	2.67	100	0.43	99.5	**13**	0.41	70.6	0.5	100
EEX-OTE	**2**	2.54	98.4	0.55	99.8	**14**	0.46	76.8	0.29	100
EEX-OTE	**3**	2.75	90.9	1.03	100	**15**	0.73	94.9	0.72	100
EEX-OTE	**4**	4.86	100	0.82	100	**16**	1.45	100	0.29	100
EEX-OTE	**5**	6.85	100	1.58	100	**17**	0.83	98.4	0.34	100
EEX-OTE	**6**	3.27	99.7	1.18	100	**18**	1.58	100	0.27	100
EEX-OTE	**7**	0.96	8.2	0.48	99.1	**19**	3.18	100	0.23	100
EEX-OTE	**8**	0.25	38.6	0.04	60	**20**	2.23	100	0.1	98.9
EEX-OTE	**9**	0.65	39.6	0.08	98.8	**21**	0.29	64	0.04	33.7
EEX-OTE	**10**	0.48	57	0.14	99.9	**22**	1.22	26.6	0.08	74.2
EEX-OTE	**11**	0.64	89	0.47	100	**23**	1.51	97.8	0.16	99.8
EEX-OTE	**12**	0.79	91.9	0.55	100	**24**	2.92	99.4	0.19	96.6
EEX-PPX	**1**	0.2	100	0.03	100	**13**	-0.11	0	0.07	0
EEX-PPX	**2**	0.41	100	0.01	1.2	**14**	-0.09	0	0.1	6.6
EEX-PPX	**3**	0.59	100	0.02	2.2	**15**	-0.09	0	0.1	5
EEX-PPX	**4**	0.64	100	-0.02	0	**16**	-0.08	0	0.09	0.2
EEX-PPX	**5**	0.58	100	0	0.6	**17**	-0.06	0	0.06	0.2
EEX-PPX	**6**	0.25	100	0.04	100	**18**	-0.02	0	0.14	92.3
EEX-PPX	**7**	0.07	0	0.08	100	**19**	-0.02	0	0.15	95.2
EEX-PPX	**8**	-0.1	0	0.18	99.6	**20**	-0.01	0	0.09	98.9
EEX-PPX	**9**	-0.1	0	0.14	92.3	**21**	-0.01	0	0.08	98
EEX-PPX	**10**	-0.12	0	0.12	8.9	**22**	0.06	0	0.08	99.7
EEX-PPX	**11**	-0.13	0	0.13	11	**23**	0.09	0	0.07	99.6
EEX-PPX	**12**	0.03	0	0.07	0	**24**	0.16	100	0.05	100
EEX-PNX	**1**	0.01	99,9	0	54.2	**13**	0.02	100	0	8.5
EEX-PNX	**2**	0	48,4	0	55.5	**14**	0.01	100	0	69.8
EEX-PNX	**3**	0.02	98,5	0.01	64.1	**15**	0	98.4	0	3.4
EEX-PNX	**4**	0.02	99,7	0	21	**16**	0	98.9	0	4.8
EEX-PNX	**5**	0	0	0	3.4	**17**	0	0	0	29.6
EEX-PNX	**6**	0.01	0	0	0.3	**18**	0.01	100	0	87.9
EEX-PNX	**7**	0.02	94,2	0	0.6	**19**	0	2.8	0	29.6
EEX-PNX	**8**	0.05	100	-0.01	0.1	**20**	0	9.3	0.01	90.1
EEX-PNX	**9**	0	97,3	0	2.2	**21**	0.02	100	0	98
EEX-PNX	**10**	0	94,5	0	22.8	**22**	0.01	100	0	98.8
EEX-PNX	**11**	0.01	100	0	60.3	**23**	0.01	100	0	61.5
EEX-PNX	**12**	0.15	100	0	2.1	**24**	0.01	8.8	0	40

Explanations: If $P(\delta_2 > 0)$>97.5 the hypothesis of convergence cannot be rejected on the 5% significant interval (two-sided test). If $P(\delta_2 > 0)$<2.5) the hypothesis of divergence cannot be rejected. The intercept indicates the initial level of integration. The number of observations in each equation is given in Table 28.

Table 21, continued: Probability of convergence as well as the estimated intercept for each hourly series of the smoothed pair wise gross and net price relations

		Gross-Series		Net-Series			Gross-Series		Net-Series	
Series		Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$	Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$		Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$	Intercept $\hat{\delta}_1$	Prob. of Converg. $P(\delta_2 > 0)$
EEX-APX	**1**	0.03	100	0.03	100	**13**	0.14	100	0.01	99.5
EEX-APX	**2**	0.03	100	0.03	100	**14**	0.27	100	0.02	99.5
EEX-APX	**3**	0.05	99.9	0.05	100	**15**	0.21	100	0.01	90.5
EEX-APX	**4**	0.07	100	0.09	99.9	**16**	0.14	100	0.01	99.4
EEX-APX	**5**	0.07	100	0.07	100	**17**	0.14	100	0.01	98.4
EEX-APX	**6**	0.09	99.9	0.09	100	**18**	0.33	100	0.06	100
EEX-APX	**7**	0.1	100	0.1	100	**19**	0.07	100	0	91.2
EEX-APX	**8**	0.03	100	0.03	100	**20**	0.04	100	0	92.6
EEX-APX	**9**	0.05	100	0.01	100	**21**	0.02	100	0.01	100
EEX-APX	**10**	0.24	100	0.02	99.9	**22**	0	100	0	100
EEX-APX	**11**	0.25	100	0.02	99.9	**23**	0.01	99	0.02	98.7
EEX-APX	**12**	0.23	100	0.01	93.2	**24**	0.01	99.5	0.01	99.2
EEX-DKE	**1**	0.38	100	0.19	100	**13**	0.06	0	0.09	100
EEX-DKE	**2**	0.62	100	0.29	100	**14**	0.05	0	0.07	95.6
EEX-DKE	**3**	0.81	100	0.39	100	**15**	0.07	0	0.06	100
EEX-DKE	**4**	0.81	100	0.4	100	**16**	0.08	0	0.07	100
EEX-DKE	**5**	0.81	100	0.36	100	**17**	0.07	0	0.05	100
EEX-DKE	**6**	0.49	100	0.21	100	**18**	0.03	0	0	0
EEX-DKE	**7**	0.25	100	0.14	100	**19**	0.03	0	0.01	0
EEX-DKE	**8**	0.07	1.3	0.06	100	**20**	0.07	0	0.05	100
EEX-DKE	**9**	0.09	1.9	0.05	100	**21**	0.08	0	0.07	100
EEX-DKE	**10**	0.07	0	0.06	98.6	**22**	0.15	100	0.1	100
EEX-DKE	**11**	0.06	0	0.07	88.4	**23**	0.14	100	0.1	100
EEX-DKE	**12**	0.21	5	0.28	100	**24**	0.26	100	0.15	100
EEX-DKW	**1**	0.09	100	0.01	97.8	**13**	0.04	0	0.01	99.9
EEX-DKW	**2**	0.2	100	0.04	100	**14**	0.03	0	0.01	100
EEX-DKW	**3**	0.29	100	0.06	100	**15**	0.04	0	0.01	100
EEX-DKW	**4**	0.33	100	0.08	99.6	**16**	0.04	0	0.01	100
EEX-DKW	**5**	0.27	100	0.05	100	**17**	0.04	0	0.01	99.6
EEX-DKW	**6**	0.14	100	0.02	100	**18**	0.02	0	0.01	95.8
EEX-DKW	**7**	0.07	100	0.01	99.7	**19**	0.01	0	0.01	98.8
EEX-DKW	**8**	0.03	0	0.01	100	**20**	0.03	0	0.01	97
EEX-DKW	**9**	0.05	0	0.01	100	**21**	0.02	0	0.01	100
EEX-DKW	**10**	0.04	0	0.01	99.9	**22**	0.06	100	0.02	100
EEX-DKW	**11**	0.03	0	0.01	100	**23**	0.04	0	0.01	100
EEX-DKW	**12**	0.12	0.4	0.03	99.8	**24**	0.07	100	0.01	99.7
PNX-OME	**1**	0.64	100	0.04	48.4	**13**	0.19	100	0.01	0
PNX-OME	**2**	0.53	100	0.03	14.1	**14**	0.2	100	0.03	0.5
PNX-OME	**3**	0.44	100	0.04	6.2	**15**	0.21	100	0.07	98.8
PNX-OME	**4**	0.39	100	0.16	3.8	**16**	0.25	100	0.05	89
PNX-OME	**5**	0.32	95.1	0.08	2.4	**17**	0.31	100	0.08	72.4
PNX-OME	**6**	0.27	100	0.05	60.2	**18**	0.35	100	0.09	20.6
PNX-OME	**7**	0.16	100	0.04	99.5	**19**	0.32	100	0.17	100
PNX-OME	**8**	0.14	100	0.11	100	**20**	0.32	100	0.09	99.9
PNX-OME	**9**	0.18	100	0.1	100	**21**	0.46	100	0.02	83.3
PNX-OME	**10**	0.16	100	0.09	64.1	**22**	0.51	100	0.04	19.2
PNX-OME	**11**	0.17	100	0.03	0.4	**23**	0.46	100	0.02	15.6
PNX-OME	**12**	0.17	100	-0.06	0	**24**	0.36	100	0.01	92

Table 28: Number of observations for the convergence test of the smoothed gross and net integration series

	PPX-OTE	EEX-OTE	EEX-PPX	EEX-PNX	EEX-APX	EEX-DKE	EEX-DKW	PNX-OME
Gross Series	1111-1137	1121-1150	1142-1145	1155-1158	1155-1158	1155-1158	1152-1158	1156-1158
Net Series	327-331	330-337	294-315	142-144	1104-1158	754-759	1144-1157	125-126
Explanation: The number of observations in each series varies slightly from hour to hour due to missing values .								

Figure 13: Smoothed integration indicator $\hat{\alpha}_t$ for the Polish-Czech (PPX-OTE) and the German-Czech (EEX-OTE) cross-border integration cases

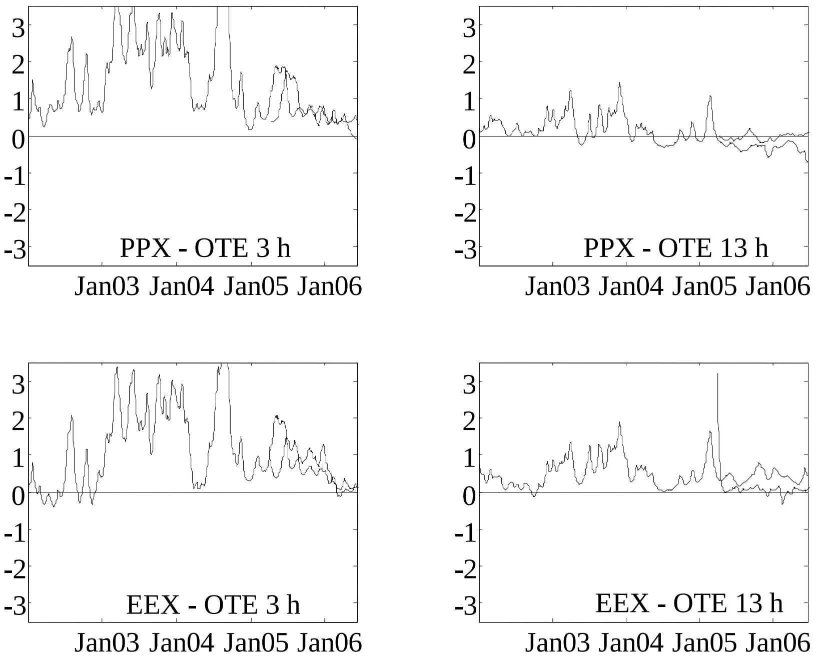


Figure 14: Smoothed integration indicator $\hat{\alpha}_t$ for the German-East Danish (EEX-DKE) and the French-Spanish (PNX-OMEL) cross-border integration cases

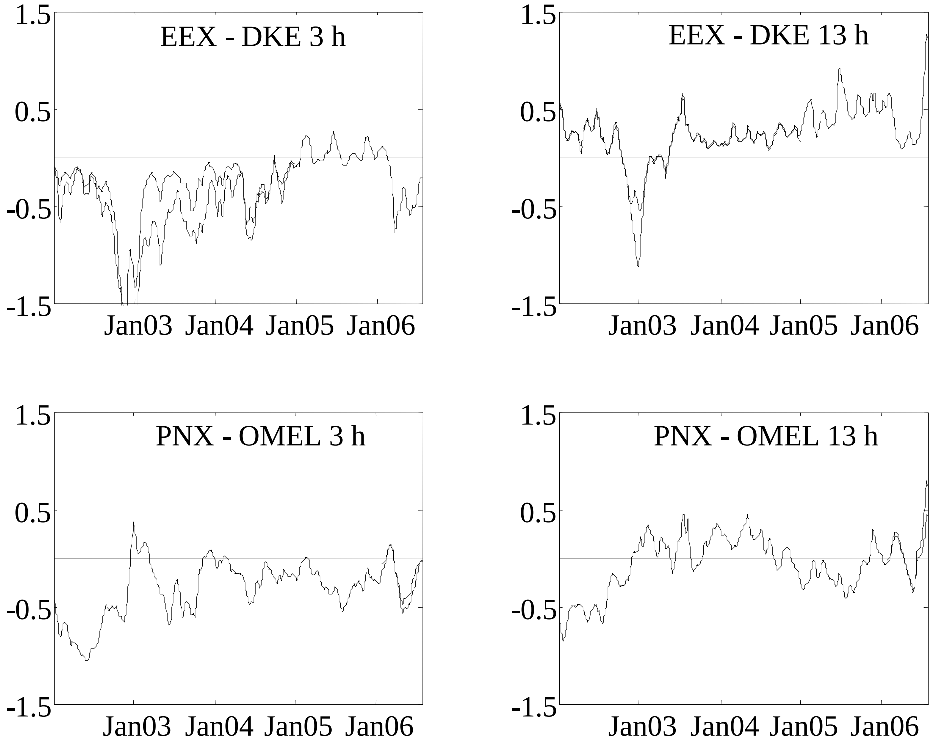
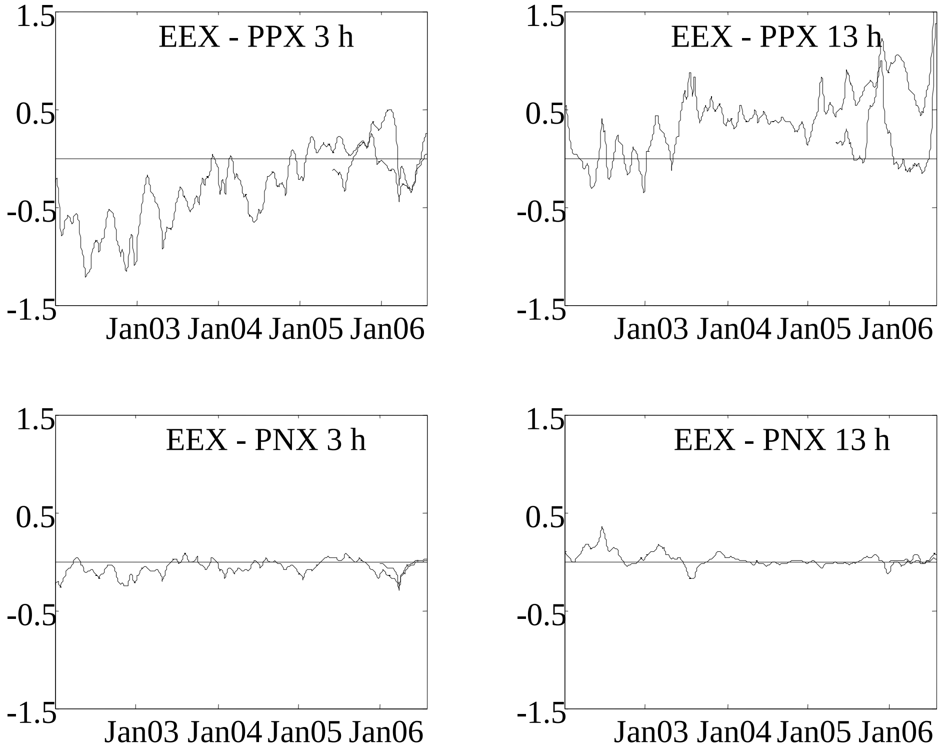


Figure 15: Smoothed integration indicator $\hat{\alpha}_t$ for the German-Polish (EEX-PPX) and the German-French (EEX-PNX) cross-border integration cases



V Market Power in Explicit Transmission Auctions[125]

V.1 Introduction

Motivated both by liberalization ambitions to facilitate more extensive, efficient wholesale trading, and the system reliability benefits of wider integration, the operation of electricity interconnectors[126] between separate markets is an active topic in both theoretical research and policy deliberations. International interconnections provide a number of benefits: substitution of less costly generation, the deferral of investment in generation, reductions in unserved energy, reductions in ancillary service costs, and the potential mitigation of market power.[127] The system operations benefits of greater transmission capacities have been proven in practice, but the potential market efficiency effects still require extensive theoretical and empirical analyses. Despite the conventional wisdom that more interconnections create a larger market and encourage competition, increased market efficiency in theory (and presumably in practice) appears to depend upon the details of the mechanisms that are actually implemented. The interconnector literature has focused on financial transmission rights (Gilbert et al. (2004), Joskow and Tirole (2000)) and the effects of congestion in nodal pricing systems (e.g. Borenstein et al. (2000), Stoft (1999)). By contrast, the market power effects in explicit auction systems have not been studied empirically so far. It is from this perspective that the practical case study examined in this chapter seeks to add new insights.

We also analyze another widely held view that market forces by themselves direct trading from a low- to a high-price area. The basic framework for devising financial transmission rights generally assumes this to be the case, following considerations of efficient arbitrage. However, we explore the circumstances in which an agent may choose to export power against the direction of efficient arbitrage. This result is a function of asymmetric market power and marginal costs between two regions. In reality, manifestations of this behavior are often elusive. In most markets it is sometimes difficult to associate physical power flows with trading because of the existence of loop flows in meshed, synchronized power systems. We use trading data from the Anglo-French Interconnector (IFA), the single, substantial but unsynchronized direct current link between these two markets that does not suffer from loop

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[125] I would like to thank Professor Derek Bunn for providing access to the unique data set of Anglo-French interconnector trades.

[126] We use “interconnector” as defined by Turvey (2006, p. 1457): “An interconnector, in the case of electricity, is a cable or overhead line connecting two separate markets or pricing areas.”

[127] Turvey (2006, p. 1457).

flow complications. From daily, company-level, flow-nomination data, we identify trades against the price differential that are consistent with the theoretically advantageous strategies available to some of the market participants. (This activity is in addition to the economic rents that dominant players can acquire via buying to withhold transmission rights.)

The chapter is structured as follows: in the next section, theoretical considerations for the exercise of market power in interconnector auctions are developed. In contrast, Section 3 describes alternative explanations for market inefficiency that result from the practical implementation of these auctions. Section 4 introduces the data and Section 5 presents the empirical results. Section 6 concludes with a discussion of the policy implications.

V.2 Inefficient Export

To begin, we envision a generating company that dominates its domestic market, but also generates in a foreign market. Both markets are linked through a limited capacity interconnector. Our hypothetical company sells electricity at the price $p_d(q_d)$ in the domestic and at price $p_f(q_f)$ in the foreign markets, whereby q_d represents the domestic and q_f the foreign sales. Its production cost function is $C(q_d + q_f)$, and the profit function is given by

$$\Pi = p_d(q_d)q_d + p_f(q_f)q_f - C(q_f + q_d). \tag{1}$$

From the first order conditions, we deduce the well-known optimal third degree price discrimination rule[128]

$$\frac{\partial p_d(q_d)}{\partial q_d}q_d + p_d \overset{!}{=} \frac{\partial p_f(q_f)}{\partial q_f}q_f + p_f \overset{!}{=} \frac{\partial C}{\partial(q_f + q_d)}. \tag{2}$$

We note that the domestic market's optimal price is higher than in the foreign market ($p_d(q_d^*) > p_f(q_f^*)$) if

$$\frac{\partial p_d(q_d^*)}{\partial q_d^*}q_d^* < \frac{\partial p_f(q_f^*)}{\partial q_f^*}q_f^*. \tag{3}$$

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[128] See Pindyck and Rubinfeld (1995, p.368 ff.).

Since the price depends negatively on the offered quantity, the domestic prices are, ceteris paribus, higher when, in equilibrium, either the company sells more in the domestic market ($q_d^* > q_f^*$), or when prices react more strongly to volumes in the domestic market. Both conditions apply if the company dominates the domestic market and is a fringe player in the foreign market. In the extreme case, our company is a *monopolist* in the domestic market (residual demand curve = actual demand curve, i.e. almost vertical for electricity markets) and a *price taker* in the foreign market (residual demand curve is horizontal). Under these conditions, the foreign price serves as opportunity cost for domestic supplies.

If we assume sufficient transmission capacities between both countries and production possible at cost $C_d\left(q\right)$ in the domestic and at $C_f\left(q\right)$ in the foreign markets, the production decision is independent of the share of total quantity sold in each market. Further, if there are significantly larger domestic than foreign inframarginal production capacities, but domestic prices are higher (for the reasons just mentioned), our monopolist would export against the price differential.[129]

We note that under certain conditions, a dominant generator may want to export electricity from the high- to the low-price area (by contrast, it benefits consumers and arbitragers to trade in the opposite direction). Prices will equalize absent trade barriers. However, limited interconnector transmission capacities will act as physical constraints. As transmission lines can only be used in one direction at a time and electricity is a homogenous good, the effect of capacity constraints on flows and prices depends crucially on the treatment of opposing flow nominations.[130] At present, transmission rights between many EU countries are auctioned

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[129] International trade influences the welfare distribution between domestic and foreign consumers and producers. The dominant generator will produce more in the domestic market if it can export; thus its marginal cost and domestic prices will increase and its domestic sales decrease. Domestic customers will lose welfare and the domestic company will gain. Foreign consumers will gain, partly at the expense of foreign suppliers. In addition to these direct welfare effects arising from flows against the price differentials, second order effects will decrease the system's dynamic efficiency. For example, price signals for investments in the more competitive market will diminish.

[130] Essentially two procedures could handle counterflow nominations:
Ex ante netting:
(1) Market participants submit their flow nominations to the interconnector operator; (2) the operator balances imports and exports; (3a) if the balance is below the capacity constraint, all nominations are accepted and only the net flow materializes; (3b) if the balance is above the capacity constraint, electricity flows at full capacity in the net direction. All nominations against the dominant direction are accepted. In the dominant direction the operator allocates nominations to the market participants via auctions or pro rata.

separately in each direction, without any “netting” (i.e. cancellation of positive and negative flow nominations).

Assuming an interconnector of fixed[131] capacity k between an oligopolistic domestic market with pricing function $p^o = 1 - Q^o$ and an adjacent foreign competitive market with $p^c \geq 0$, we can show that

1) A dominant will nominate electricity against the price differential
2) If all acquired transmission rights must be used (no withholding), the electricity flow direction depends on the number of traders
3) Irrespective of the number of traders, a dominant will buy all importation rights and withhold them (if allowed) and electricity will flow against the price differential.

Next, we look at a dominant M in the oligopolistic market that can produce up to a capacity of $Q \geq q_d + q_f > 1$ with zero cost. Additionally n symmetric traders $T_1 \ldots T_n$ exist. All companies can buy and sell in both markets with I_j being the net imports of trader j. We can define the profit functions as

$$\Pi_M = \left(1 - q_d - \sum_{i=1}^{n} I_i\right)(q_d) + p^c q_f \tag{4}$$

$$\Pi_{T_j} = \left(1 - q_d - \sum_{i=1}^{n} I_i\right)(I_j) - p^c I_j \tag{5}$$

Absent congestion, all players will behave in the oligopolistic market as oligopolists with cost p^c selling $q_d = I_j = \frac{1 - p^c}{n + 2}$. Thus, the price in the oligopolistic market $p^o = 1 - \frac{(n+1)(1 - p^c)}{(n+2)}$ converges to the price in the competitive market if more traders enter. Because of its cost advantage, the dominant will sell all of its remaining production $q_f = Q - q_d$ in the

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No netting:
(1) Market participants submit their flow nominations to the operator; (2) In each direction only nominations up to the line capacity are allowed. Thus, the capacity in each direction is allocated separately to the respective bidders via auctions or pro rata. No electricity will flow if export and import demand are higher than the line capacity.

[131] We assume fixed capacity in contrast to Hoeffler and Wittmann (2006) who assume the capacity to be chosen by a profit maximizing auctioneer.

competitive market. As $q_f > \frac{n}{n+2}\left(1 - p^c\right)$, electricity will flow from the high- to the low-price area.

If congestion is present ($k < Q - q_d$), the capacities are auctioned separately in each direction, and no electricity will flow as long as $k < \frac{n}{n+2}\left(1 - p^c\right)$, because the traders will buy all importation rights and import at $\sum_{i=1}^{n} I_i = k$, and the dominant will buy all exportation rights and export at $q_f = k$.

Will it profit the dominant if it is allowed to buy importation rights but not use them (withholding)? Assuming an auction for the importation rights, this is equivalent to asking whether the dominant has a higher marginal willingness than traders to pay for the importation rights as in

$$-\frac{\partial \Pi_M}{\partial I_i} > \frac{\partial \Pi_T}{\partial I} \qquad (6)$$

From $-\frac{\partial \Pi_M}{\partial I_i} = q_d$ and $\frac{\partial \Pi_T}{\partial I_i} = 1 - q_d - (n+1)I_i - p^c$ it follows that $2q_d > 1 - (n+1)I_i - p^c$. Because congestion is present, the dominant need not react to the traders' volumes, and its optimal strategy is $q_d{*} = \frac{1 - nI_i - p^c}{2}$. Thus, it will buy and withhold all importation rights as long as $1 - nI_i - p^c > 1 - (n+1)I_i - p^c$. This holds for any number of traders.[132]

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[132] Note that the price of export rights should be zero because only the dominant desires to export. The price of import rights should be in the interval $\left[P^O - P^C, \frac{1-k-p^c}{2}\right]$, i.e. between the dominant's and the trader's maximum willingness to pay, depending on the auction mechanism.

Given a low-cost dominant in the domestic market with capacity constraint access to a more competitive foreign market, and the previous theoretical analysis, we expect to observe the following market characteristics:

1) A dominant generator may be observed in practice to be exporting against the price differential, but not importing against the price differential.
2) A trader should always trade from the low- to the high-price area and thus sometimes against the dominant's trading direction.
3) If withholding is allowed, the dominant will only withhold import rights.
4) Traders will not withhold transmission rights.

In reality, of course, electricity markets are complex and dynamic. For example, a producer may be a "natural" monopolist during off-peak but an oligopolist during on-peak. Nevertheless, by having a capacity-constrained link between a concentrated market with an occasionally low-cost dominant and an occasionally more competitive market, we can deduce and test these two hypotheses:

1) The dominant will behave asymmetrically, predominantly withholding in the import direction and trading against the price differential mainly in the export direction.
2) The dominant will behave quite differently from the non-dominant generators and traders.

The analysis above is consistent with a general view (e.g. Bonardi (2004)) that after deregulation, dominant incumbents usually seek to maximize monopoly rents at home while acting opportunistically abroad.

V.3 Auction Mechanisms and Microstructure Effects

Aside from the use of market power by dominant participants, studies of the performance of capacity auctions for allocating interconnector transmission rights have discussed the inefficiencies that result from market design and microstructure effects. In Europe, where ex ante auctions are the prevailing cross-border congestion management scheme between separate power markets which, for political, proprietary, regulatory or other reasons cannot be easily unified into extended nodal pricing regions, ETSO (2004), CONSENTEC (2004) and the EC (2007), among others, have examined design effectiveness. Auctions for interconnector capacity may take place annually, quarterly and weekly for blocks of time, and then close with day-ahead prices. If they work well, the interconnectors will operate to capacity at prices that reflect the arbitrage value of trading physical power between the two connected spot markets. But this has not generally been the case, and experts have identified several concerns:

1) In most cases, apart from the single Anglo-French link, a meshed system makes calculating the available capacities at each link a challenging task. Significant security margins must be included, reducing the real transmission capacity and according to Glachant and Pignon (2005, p. 153), “TSOs, therefore, define the congestion signal on a variable, complex and non-transparent constraint and may manipulate it”. Hoeffler and Wittmann (2006) suggest that profit maximizing auctioneers in such auctions would lead to welfare losses.

2) The sequence of transmission and energy markets produces uncertainty. The transmission auctions usually precede the energy markets. As shown empirically in Chapter IV and theoretically by Ehrenmann and Smeers (2005), prediction errors in the market spreads lead to inefficient prices in the prior transmission capacity auctions. These temporal uncertainties can be further confounded by the varied closing times for the energy spot markets.

3) Flows are usually permitted to be nominated up to their physical capacity in each direction, without fully considering how counter-nominations will reduce the net flows. Thus, separate auctions of capacity in both directions may fail to induce full interconnector usage.

4) Some market mechanisms do not require participants to return the forward capacity reservations which they do not intend to use the next day to the day-ahead market.

5) Markets may not be sufficiently liquid to induce efficient prices. Spot prices may be easily moved by small trades and traders may lack confidence that they can close out final positions at a fair price.

6) System operators on one or both sides of a link may need to be proactive in scheduling cross-border flows for congestion and system balancing purposes. These activities would generally be expected to take place the day after the trading markets close, and constitute a further reason why substantial capacity is withheld from the market.

7) The major reference prices may not fully reflect locational prices for taking or delivering power at the ends of the interconnectors. Even without nodal prices, there may be different locational supplements to reflect system losses.

8) Local congestion close to the ends of a link can induce local generators to anticipate domestic output constraints and compensate by nominating some power for export.

9) Electricity may not be a homogenous commodity on one or both sides of a link. Some countries have special supplements for delivering power from renewable sources, e.g. the Netherlands and the UK. These would not be apparent in the wholesale market prices, and the non-transparency of “green” volumes could distort the implied direction of arbitrage.

All of these issues, with the exception of the last two, will similarly affect all market participants. The main propositions which we identified in section 2 concern differences in the interconnector usage of dominant and non-dominant companies. With microstructure effects affecting both types of companies similarly, an empirically based analysis of distinct dominant behavior may still be possible.

V.4 Data from the Anglo-French Interconnector

The Anglo-French Interconnector (IFA) consists of four 45 km submarine DC cables between Calais and Folkstone that allow transmission of 2000 MW in either direction. It is jointly operated by the French Réseau de transport d’électricité (RTE) and UK National Grid (NG) transmission system operators.[133] In 2005 the absolute electricity flows totaled 12 TWh, and traders were willing to pay more than € 125 m for the usage of this vital link.[134]

The economics of the IFA have not yet been extensively studied. Inderst and Ottaviani (2004) provide a general description of the linked markets, the auctioning mechanism, and IFA's ownership, but they do not make use of the extensive, publicly available data to analyze whether the IFA actually achieves efficient arbitrage. Turvey (2006) provides some graphical indication that the electricity exports from France to the UK are occasionally directed against the price difference, as does the EC Sector Inquiry (2007), while CONSENTEC (2004) shows that the link between price differential and flows is significant but low.

We select three datasets: the electricity spot prices on both sides of the IFA, the results of the IFA-capacity auctions and the IFA-flow nominations. Our sample period consists of 1,011 working days from 2002 to 2005.

(a) Electricity Price Data

We obtained hourly wholesale electricity prices for France from PNX and downloaded the half hourly electricity prices for UKPX from Datastream. Since both countries did *not* apply locational pricing, we apply a single price for each country. We note that a substantial shortcoming of the data is the low liquidity of both markets. Only about 2% of the national electricity consumption is traded on the UKPX and just over 3% on the PNX.[135] In fact, more spot trading in the UK takes place via brokers (OTC trade accounts for about 9%) than via the UKPX (see the Appendix for a comparison of OTC and UKPX prices). We find that price deviations between OTC and power exchange are insignificant during both base and on-peak periods. In contrast to the UKPX where trading takes place continually until one hour ahead of real time, the PNX applies a one-shot auction the day before delivery. This raises the question of whether the ex post price differential is a valid measure for the efficiency of traders' arbitrage operations. One could surmise that at the margin a profitable deal in the day-ahead market (e.g. buy in France at the French price p(F,t) and sell in the UK at the

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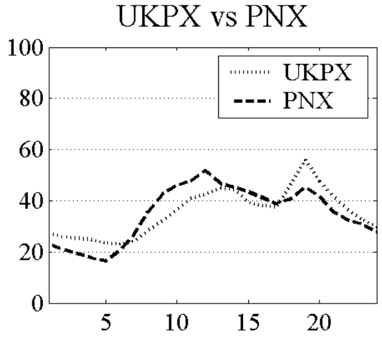
[133] This has led to discussions in the UK about how to properly regulate the interconnector, since French law does not allow Ofgem to regulate RTE. [DTI (2005)]

[134] "Absolute flows" refers to 11.4 TWh imports to the UK and 0.8 TWh exports from the UK. The presented figure for the willingness to pay only accounts for annual (800 MW), seasonal (300 MW), quarterly (300 MW) and monthly (350 MW) auctions and is thus ignoring weekend and daily auctions.

[135] EC (2007).

British price p(UK,t)>p(F,t)) is ex post unprofitable since the UKPX price may fall somewhat after the completion of the deal. Even if this effect was noticeable and traders were unable to forecast it, this bias is a minor concern for our analysis, because it would occur symmetrically in both directions and affect all market participants.

Figure 16: Average electricity prices at each hour of the day 2002-2005 (in €/MWh)



Another concern is the associated transaction cost. It consists of (at least) five components for the IFA:

1) Balancing Services Use of System (BSUoS) charges: Depending on the market situation these costs can change from day to day; the underlying cost-formula depends on several factors. It is difficult both to forecast and to assess their influence on traders' transaction costs; therefore, we do not include them in our analysis.

2) Balancing market (ELEXON) participation fees: These are independent of traded volumes and thus unimportant for our analysis. However, they may create a barrier to entry.

3) A symmetric loss factor of 1.17% is applied for all IFA flow nominations, i.e. when withdrawing 100.00 MWh in market A, one must feed 101.17 MWh into market B. In all subsequent analysis we account for the loss factor.

4) Transmission Network Use of System (TNUoS) charges: These unpredictable charges differ when bringing electricity from England to France (TNUoS Demand) and in the opposite direction (TNUoS Generation). An interconnector user only pays the TNUoS Demand Pass Through Charge when both it and the entire IFA nominate electricity to France during at least one of three "Triad Charging Half Hour Periods"[136]. The individual

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[136] They are the three ex post deduced periods of highest electricity peak demand from November to February. Note that each of these Triad Charging Half Hour Periods must be separated by at least 10 days from the previous one.

charge is then calculated according to average interconnector imports during the three Triad Periods times the Zonal Demand Tariff (ZDT)[137] times the individual share of the Triad imports. We approximate the effect of this charge as expected importing cost (ZDT/(number of potential half hours)) in £/MWh for the on-peak half hours with significantly above average on-peak prices in winter months. The TNUoS Generation Charge is levied on export (France to the UK) capacity holders. The total payable amount of £ 2,630,056.41 (2005/06) is distributed to the users according to their export capacity holdings. Assuming 90% of the available capacity being allocated (not ultimately used), each export capacity holder must bear 0.17 £/MWh of its export capacity held. We include this charge in our analysis.

5) Capacity charge for obtaining unidirectional transmission rights (this is the main capacity auction price): The capacity at the IFA is sold to interested parties via a sequence of auctions. Table 29 indicates that auction results (ignoring daily auctions) are quite volatile, ranging from 4.3 to 22.5 €/MWh for exports and 0.43 to 1.26 €/MWh for imports.[138] A variety of players enter most of the bids in one auction (number of winning bids in brackets). We note that the distribution of the total volume for the products offered at the auctions varies in our sample period. Therefore Table 29 is not representative for the entire sample period.

Table 29: Summary of products and prices at the IFA

Product	Auction Date	F to UK Volume in MWh (no. of bids)	Price in €/MWh	UK to F Volume in MWh (no. of bids)	Price in €/MWh
Daily: 10Apr06	9Apr06	50	**9.88** (0.13[139])	150	**9.83**
Weekend: 8-9Apr06	7Apr06	100	**17.5**	0	**0**
Monthly: 4/2006	9Mar06	150 (4)	**6.28**	150 (5)	**0.74**
	21Mar06	150 (6)	**10.77**	150 (4)	**0.55**
Quarterly: 4/06-6/06	16Mar06	150 (4)	**7.50**	150 (4)	**0.61**
	7Mar06	150 (6)	**6.30**	150 (5)	**1.22**
Seasonal: Summer06	2Mar06	175 (6)	**4.28**	175 (5)	**1.26**
	14Mar06	175 (4)	**6.83**	175 (4)	**0.71**
Annual (Apr-Mar): 4/06-3/07	7Feb06	175 (6)	**15.76**	175 (6)	**0.61**
	28Feb06	175 (6)	**9.00**	175 (4)	**0.77**
Annual (Jan-Dec):	8Nov05	250 (7)	**16.50**	250 (4)	**0.43**

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[137] 2005-2006 in the South-East, Zone 11: 15,989.41 £/MWh.

[138] In this dissertation, we define import and export with respect to France, i.e. bringing electricity from France to the UK is defined as export.

[139] We report the second price because it differed significantly from the first price. In all other cases, the prices of all winning bids differed by only a few cents/MWh.

2006	29Nov05	250 (7)	**22.50**	250 (8)	**0.47**

(b) Transmission Capacity Auction Prices and Volumes

All auction data are obtained from the French grid operator RTE which provides extensive coverage of the IFA data on its website.[140] In general, day-ahead prices for imports to France (avg.: 0.5 €/MWh) are lower than for exports to the UK (avg.: 2.0 €/MWh). Figure 17 shows that the variances of the day-ahead price series are highly clustered and that imports are generally more expensive in winter. The significant spike in 2003 is explained by the very high import prices on the Continent during that extraordinarily hot summer.

When comparing the prices, the frequency of large differences between auctions for the same period are particularly striking (e.g. the prices of the two import auctions for 2006 held on 8th and 29th of November 2005 differ by 36%)[141]. These differences make it unlikely that the results are only based on a change of expectations or the open positions of the individual players. It may be that in some circumstances the auction mechanism (see Table 30) and the limited number of participants allow traders to conceal their true willingness to pay and thus achieve lower prices. The open bid auction explains why the winning bids are so close (e.g., for the annual auction of 8th November, the winning bids were: 144.5, 144.3, 144.25, 144.2, 144.15, 144.12 and 144.1 thousand Euro, i.e. in the range of 0.2%).[142]

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[140] http://www.rte-france.com/htm/fr/vie/historiques_angleterre.jsp

[141] Practitioners link this increase to the coinciding gas price increases: the NBP price of UK gas futures for 2006 increased from 53.5 to 61 pence per therm (14%) in the same period.

[142] Due to the importance of periodic auctions (90% of the volumes) and their rather uncommon structure, the auction mechanism is briefly introduced. The auctions are held several weeks before the beginning of the delivery period. After the opening of the auction, bids may be entered for 15-30 minutes. After the first 15 minutes, the auction closes at a randomly selected point in the next 15 minutes. The auction can be repeatedly extended by 2 minutes, when new bids (of a certain minimum bid size) are entered. In addition, a certain (known) reservation price exists. Throughout the entire auction process, all bids are known to all participants.

Figure 17: Results of daily auctions of capacities of the Anglo-French Interconnector

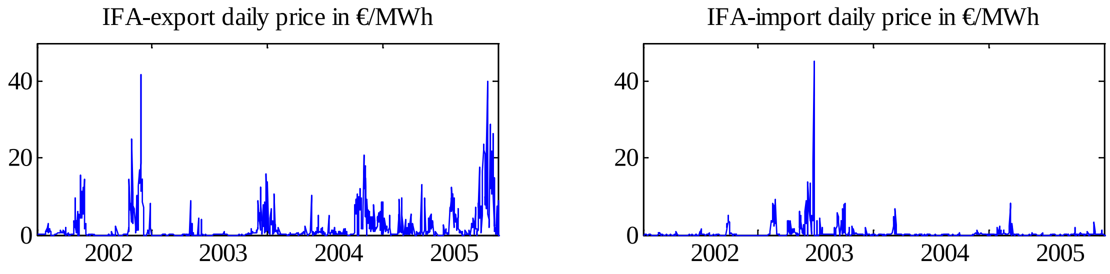

Table 30: Comparison of the IFA and the German-Dutch interconnector

	IFA	TenneT (RWE-TenneT)
Auction price setting	Discriminatory (pay as bid)	uniform price (last accepted offer)
Auction mechanism	Open bid	Sealed bid
Closing time of periodical auctions	random closing within a 15 min. range	fixed closing
Closing time of day-ahead auctions	8.15	9.00
Closing time of the linked spot markets	PNX: day ahead 11.00 am UKPX: hour ahead	APX: day ahead 10.30 am EEX: day ahead 12.00 am
Usage requirements	Capacity not nominated in t-1 is given back to the daily auction	Capacity not nominated in t-1 is given back to the daily auction
Number of products	7 (see Table 29)	3 (annual, monthly, daily)
Daily products	Base	24 single hours
Reselling	Allowed, but uncommon[143]	Allowed
Netting	No	No
Intraday market	No	No
	Only DC link between two asynchronous systems	Part of a meshed synchronous AC grid
	contract transmission path = physical transmission path	contract transmission path =/= physical transmission path

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[143] RTE has established a corresponding trading platform that is apparently not as popular with traders. [www.rte-france.com/htm/fr/offre/telecharge/Recapitulatif_des_reponses_clients_pour_WEB.pdf (25Apr06)]

(c) Company Level Data on IFA Usage

Our third dataset consists of half hourly company level data on IFA usage. In our sample period, 27 companies actively traded across the English Channel. The usage is modestly concentrated (See Figure 19). The five largest players in the IFA market together account for 72% of the exports (Herfendale-Hirshman Index (HHI) of 1570) and 71% of the imports (HHI: 1155). But the linked energy markets are quite disparate. Electricité de France dominates the French market (over 90% market share) while the UK market is characterized by many generators (HHI: below 900). Figure 18 indicates that electricity mainly flows from France to the UK in off-peak periods and in both directions in on-peak periods with almost equal probability.

Figure 18: Aggregated flows (daily pattern in MWh)

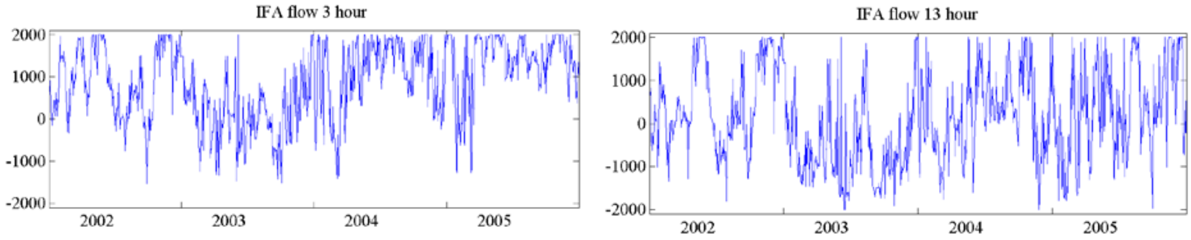
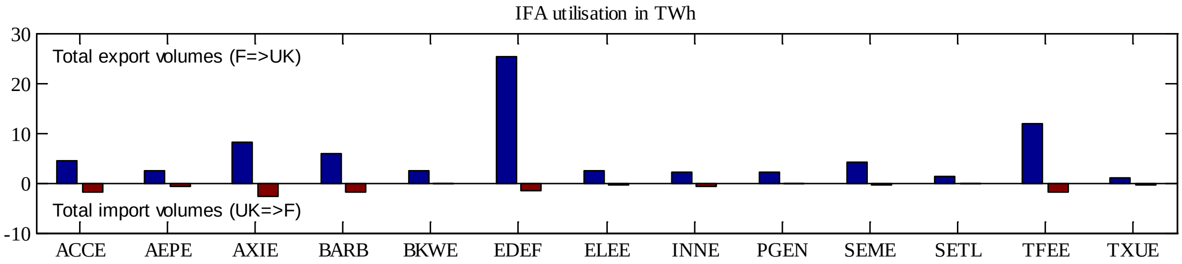


Figure 19: Company level usage[144]



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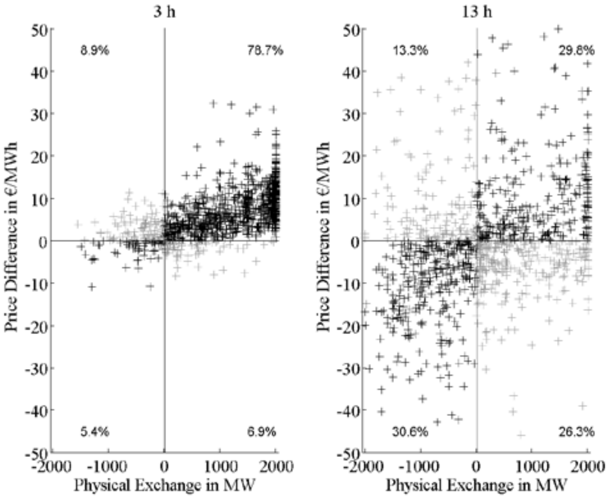
[144] See the Appendix for a list of companies.

V.5 Empirical Analysis

Figure 20 plots the physical electricity exchange between the UK and France versus the corresponding price difference for representative off-peak (3h) and on-peak hours (13h). During off-peak, electricity flows from France to the UK in 86% of the 1,011 considered hours. Electricity is thus usually flowing from the low- to the high-price area, but the capacity is rarely fully utilized even when significant price differentials persist.

While electricity flows in the “right” direction 84% of the time during off-peak, it flows against the price differential around 40% of the time during on-peak. The seemingly random distribution of the dots in the second part of Figure 20 indicates that the statistical link between flows and price differential is very weak during on-peak times (correlation coefficient is 17%).

Figure 20: Physical exchange vs. price difference



To capture the physical exchange/price differential, we create an inefficiency indicator. For each hour we calculate the product of the arbitrage potential[145] and the unused capacity in the profitable direction[146] and find a positive value in Euros. In the extreme case, high price differentials persist even though much of the capacity remains unused. When price differentials are zero or the capacity is fully utilized in the arbitrage direction, the inefficiencies are zero by definition.[147] This gives a static value of the unused capacity.[148] We

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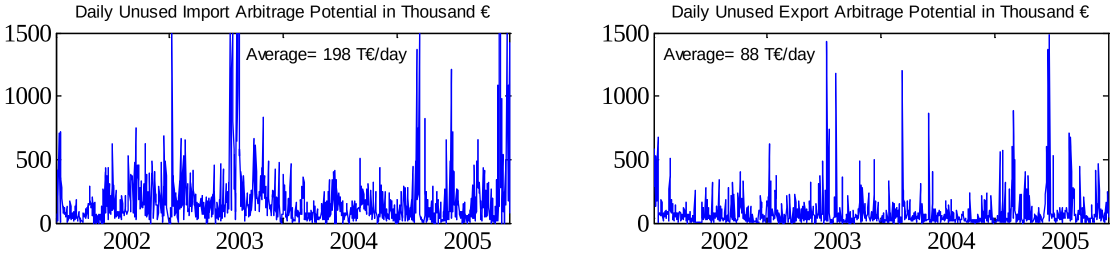
[145] The arbitrage potential is the price differential accounting for the loss factor and the TNUoS charges.

[146] Note that the unused capacity can even exceed the total capacity when the IFA is used against the market force.

[147] Observations where flows are exactly zero are assumed to indicate that unused capacities are zero due to technical disruptions, e.g. maintenance, accident or flow switching.

plot the daily results of this indicator (see Figure 21), indicating that the inefficiencies are rather volatile and occasionally spike when prices in France or the UK are unusually high. (Total inefficiencies were € 289 m between 2002 and 2005.) Most inefficiency at the IFA occurs when the price differential suggests that France should import electricity (€ 200 m). However, this rarely occurs, and electricity is traded against the market force.

Figure 21: Inefficiency indicator



We suggest the following five causes for the capacity under-usage we observe in the IFA:

1) Either the French or the UK power exchange does not provide the relevant price signals for their respective markets.[149]

2) The risk averse behavior of traders in the uncertain cross-border markets could impede full arbitrage.[150]

3) The absence of netting: the unused capacity due to netting is the capacity in the flow direction that can additionally be freed when flows in the opposite direction are considered. Overall, 808 GWh importing capacity worth € 6.6 m and 816 GWh exporting capacity worth € 2.9 m could have been freed in the years 2002 to 2005 if ex ante netting were applied.[151] However, this is only slightly more than one percent of the total capacity in each direction.

4) Strategic players may intentionally trade against the price differential to influence prices.

5) Companies block capacities by neither using nor returning acquired transmission rights.

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[148] Note that the true value should be lower because the correct usage of the IFA would result in price convergence.

[149] The reasons are inter alia the trading dynamics, transaction costs, hidden locational pricing and green power support schemes.

[150] Risk aversion of traders in explicit auctions is an issue. As traders sequentially have to buy capacity buy electricity in one market, and sell the electricity in another, they need to hold open positions. Only when they accomplish the last of the three operations will they know how much they earned/lost.

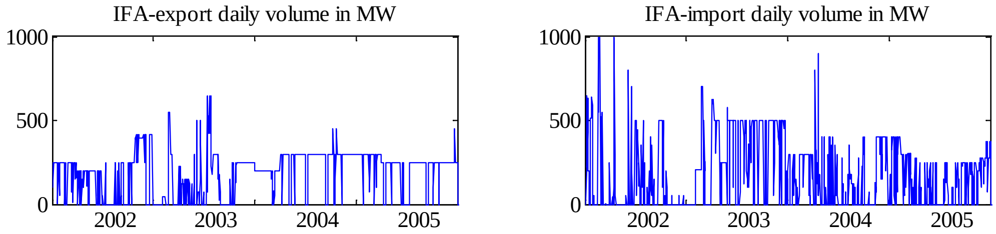
[151] The value is computed with respect to the corresponding arbitrage potential.

The last two points are closely related to the testable propositions suggested in Section 2. Therefore, withholding and trade against the price direction are examined below.

(a)Withholding

Although the use it or lose it principle is theoretically implemented via the requirement of a day-ahead (6:00 a.m.) Confirmation And Reallocation notice (CAR notice), it remains unclear whether this notice has any binding power. If a trader announces its intention to use the entire capacity acquired in periodic auctions, it will not be forced to return any unused capacity to the auctioneer who would otherwise reallocate it in the daily auctions.[152] In reality, the capacities are seldom returned. Despite the underused capacity in both directions, the capacities at the daily auction are rarely larger than the size of the custom auction, indicating that no capacity has been returned to the auctioneer (see Figure 7). At this point, there are two reservations: *First*, deviations from the use it or lose it principle are not necessarily faulty since they may, for example, give traders increased flexibility. *Second*, a portion of this apparent withholding may be due to the daily nature of the auction. If, for example, a trader intends to use a certain capacity only in a single half-hour of the day, the remaining 47 half-hours cannot be sold in daily auctions.

Figure 22: Volumes offered in daily IFA auctions



The magnitude of withholding can only be studied by learning the share of the transmission rights each company owns. Unfortunately for researchers, this data is non-public. But given

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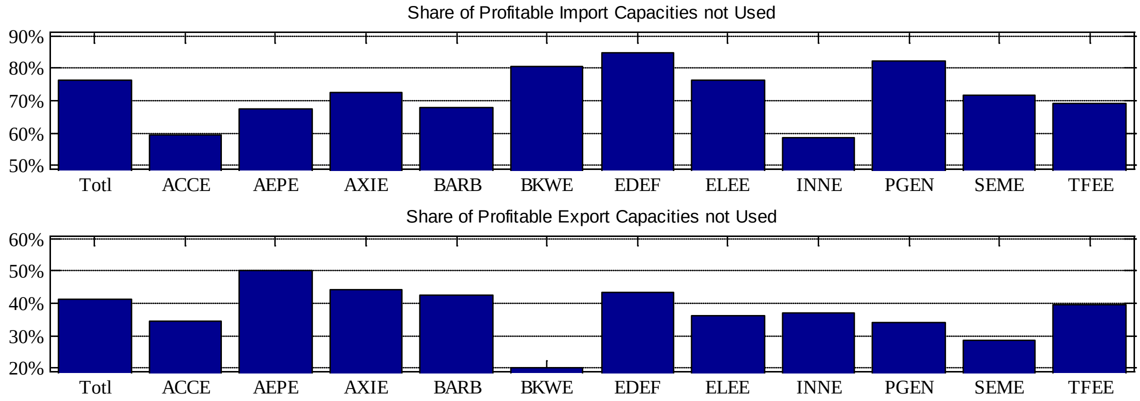
[152] "If Users notify the operators around 36 hours in advance that surplus capacity is not required, it will be offered in the daily auction and if sold, the User will receive the proceeds (with some adjustments). However, in order to avoid blocking, if capacity is neither used nor notified as not required, it will be lost - the principle of 'Use It or Lose It'." [Frequently Asked Questions Website of National Grid on the IFA]. The question is who will then use such "lost capacities". The firmly binding capacity notifications are the so-called Mid Channel Nominations. Those must be submitted at 11:00 p.m. (d-1) i.e., after the end of the daily auctions.

the infrequency of secondary market operations involving the IFA-capacity rights, we can approximate the companies' capacity rights by using their half-hourly IFA nominations. The idea is that the maximal nomination of a month minus the volume of the daily auction is the lower bound for the quantity of capacity rights a company holds in that month. We calculate this monthly quantity for each company.

Figure 23: Withholding by the eleven largest interconnector users



The value of withheld capacities (weighted with the arbitrage potential) is significant and totals € 65 m in exports and € 100 m in imports. Further checking confirms that this value is consistent for exports since the total capacity owned by companies averages 1400 MW, and for only one month surpasses the 2000 MW threshold. For imports however, we estimate the total capacity owned is only 740 MW (because some capacities are never fully utilized, even though all are sold). Thus, we know that some companies own these importation rights without either using them or returning them to the auctioneer.

Figure 23 indicates that the share of import rights (75%) significantly exceeds the share of export rights (40%) that are not used despite being profitable. The British Powergen (PGEN) – an affiliate of the German E.ON – and the French Electricité de France (EDEF) are the players that forfeit the highest share of profitable import rights. As the French and German markets are rather concentrated the results for PGEN and EDEF are in line with the hypothesis that those companies have the strongest interest to withhold import rights to protect their domestic markets. In fact, both types of predicted withholding asymmetries occur: The two companies withhold a higher share of profitable import rights than their peer group and they withhold more import than export rights (even when corrected for the common bias)[153]. An alternative explanation however is that EDEF and PGEN prefer to own some import rights as assurance against becoming short in their domestic market. Although, both companies might have an interest in owning abundant import rights, not using them fully raises an issue of profit management.

(b) Trade against the Price Differential

Exporting against arbitrage occurs more frequently than over-importation. This coincides with our theoretical analysis in Section 2 (continental European electricity markets are substantially more concentrated than the UK market). However, various alternative explanations for the irregular flows must be considered.

First, IFA-flows may be partially driven by intra-country dispatching considerations. Here it is worth noting that northern France is an exporting area with installed capacity exceeding local demand, whereas southeast England (including Greater London) is an importing area. There is no substantial evidence that significant congestion exists in northern France to restrict the output of plants in the region. London Economics (2007) did not identify this as a reason for the reduced outputs of French nuclear plants. There is evidence of system operator-motivated trades against the price differential for balancing purposes, but not of generators making inefficient nominations in the expectation of being constrained.

Second, Trading dynamics may be responsible for the ex post impression of flow nominations against the price differential. This, however, fails to justify why over-exportation is much more widespread than over-importation.

Third, Because of the UK’s green power support schemes, continental companies could desire to export electricity from France to the UK even if the French wholesale prices are higher. In the UK, commercial electricity consumers usually must pay a Climate Change Levy (CCL) on each unit of electricity consumed (4.3 £/MWh in 2005). An exemption is granted if a supplier can show that the electricity consumed was produced from renewable sources. For this

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[153] The five companies with above average ratio of Share of import rights withholding divided by share of export rights withholding are: BKWE, SEME, PGEN, ELEE and EDEF.

purpose, Levy Exemption Certificates (LECs) are issued for each MWh of green electricity generated and consumed under this scheme. Foreign plants can also produce these LECs if the electricity is generated according to the rules and consumed within the UK. The foreign generator must assure the UK regulator that the corresponding amount of green electricity was produced by the certified power station and that the company has credible transmission access from the green source to the UK's consumers. Estimates indicate that on average about a quarter[154] of the IFA's import capacity should have been used for such "green power flows", but given the nature of renewables, the output profile is variable. The trades are not tagged, however, and the generators are only required to produce aggregate monthly accounts. Thus, the LECs are not necessarily linked as supplements to the energy price spreads in specific trading periods. Unless generators claim a large fraction of LECs in their total exported power to the UK, it does not appear that this necessarily motivates inefficient arbitrage. Therefore, the manifest effect that electricity flows into the UK against the price differential could be due to the additional exportation incentives from the continental LECs. Yet the nature of the LEC-accounting suggests this is an insufficient reason.

Fourth, to explore whether strategic considerations are partly driving the over-export, it is helpful to identify whether only specific companies (low-cost domestic dominants) tend to occasionally over-export both with respect to their peer group and to their own over-imports. The company level flow nominations do reveal some irregular behaviors. In the previous section, we identified EDEF and PGEN as the two companies with the highest share of unused import capacities. In addition, both companies are found to over-export significantly more than they over-import: Whilst for the entire sample the ratio of exports against the price differential to imports against the price differential is 5.57, it is 16.95 for EDEF and 14.08 for PGEN. Thus, we test whether the trading decisions of EDEF and PGEN are significantly different from those of the other companies. We establish a binary-variable, panel-data model of each company-level import/export decision (with $T_{i,t} = 1$ standing for an export and $T_{i,t} = 0$ for an import)[155]:

$$T_{i,t} = \alpha + \alpha^{\Delta} D + \beta \Delta p_t + \beta^{\Delta} D \Delta p_t + \gamma \overline{\eta}_{i,t} + \gamma^{\Delta} D \overline{\eta}_{i,t} + \varepsilon_{i,t} \qquad (7)$$

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[154] Source: Ofgem's Website. On average 458 MWh of LECs were produced in each hour between April 2004 and October 2006. Of these, Electricité de France held 19%, E.ON 2% and RWE 2%, with the remainder being widely distributed.

[155] For each company, all dates where this company did not trade the interconnector were excluded from the sample.

In (7), each trading decision depends on a common constant (α), the common impact of the price differentials $\left(\beta\Delta p_t\right)$ and the common impact of the trading decisions of all other companies $\left(\gamma\overline{\eta}_{i,t}\right)$. Thereby, $\overline{\eta}_{i,t}$ is the sum of trading decisions of all other companies not explained by the price differential, i.e. the residual vector of the ancillary (ordinary) regression $ST_{i,t} = \phi_1 + \phi_2\Delta p_t + \overline{\eta}_{i,t}$, with $ST_{i,t} = \sum_{i\neq j} T_{j,t}$. To identify the deviations of EDEF and PGEN from the average trading strategy, the three terms, $\alpha^{\Delta}D$, $\beta^{\Delta}D\Delta p_t$ and $\gamma^{\Delta}D\overline{\eta}_{i,t}$, are included in the logit estimation. Thus, D is a Dummy vector with ones for i being EDEF or PGEN and zeros otherwise. Testing whether those two companies' behavior deviate from the average trading strategy is carried out by checking if either some or all of the group-specific coefficients (α^{Δ}, β^{Δ}, γ^{Δ}) are significantly different from zero.

Table 31: Results of the panel-data logit model of each company-level import/export decision

Variable	Coefficient	t-statistic	t-probability
α	-0.063	-5.648	0.000
α^{Δ}	1.468	57.575	0.000
β	0.043	82.436	0.000
β^{Δ}	-0.014	-14.918	0.000
γ	0.441	179.397	0.000
γ^{Δ}	-0.118	-23.318	0.000

McFadden R-squared = 0.5869
LR-ratio, 2*(Lu-Lr) = 106,471
Log-Likelihood = -37,463
Number of observations = 153,830
number of variables = 6
Number of 0's; = 42,532
Number of 1's = 111,298

The results in Table 31 provide strong evidence for the hypothesis that the two companies' trading behaviors deviate markedly from the average strategy: in contrast to the average trader, EDEF and PGEN feature significant exports unexplained by price differentials and common trading decisions (α^{Δ}= 1.47***); they react less on prices than their competitors (β^{Δ}=-0.014***) and trade less in line with the trading decision off all other companies (γ^{Δ}=-0.118***). This implies that those two companies' trading decisions are particularly affected by company-specific considerations that overrule pure electricity market arbitrage incentives.

The result that EDEF significantly over-exports confirms empirical evidence consistent with the model we present in Section 2. We reiterate the following points:

1) EDEF is a quasi-monopolist in France (~90% of generation) and a small player in the UK (~9%).[156] Further, the French market is price sensitive to the interconnector volumes (London Economics, 2007).

2) The UK market is generally considered more competitive than the French market.

3) EDEF's generation costs (mainly nuclear) are occasionally considerably lower than UK prices.[157]

In sum, our theoretical possibility that dominant companies can indeed over-export from the Continent and that electricity may thereby flow from the high- to the low-price area is plausible. Overall, it appears that some local congestion may motivate nominations, and that the benefits of green CCL-exempt supplements encourage a significant amount of trading. Taken together, they do not appear to offer a complete explanation for the amount of inefficient arbitrage. This leaves room for the theoretically attractive explanation of dominant market power for which our empirical evidence is circumstantially persuasive. In this context, the Sector Inquiry of the European Commission (EC, 2007) contains a relevant pricing sensitivity analysis by London Economics, which faced difficulties in reconciling the declared and actual output of Electricité de France's nuclear plants, and in the end concluded, "one must consider the possibility that this company has engaged in behavior consistent with the systematic withdrawal of nuclear capacity in this market" (EC, 2007, p.252).

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[156] Electricité de France considers itself as being willing and able to profitably withhold. When Pierre Gadonneix (Chair and Chief executive officer of Electricité de France) presented the Consolidated Annual Results of 2005, he explicitly asserted that "Priority is given to margin against market share" [http://www.edf.fr/70945d/Homecom/Press/BookPresseRA20030226VAPDF].

[157] The same argument also holds for PGEN (E.ON holds a generation market share of 24% in Germany).

V.6 Conclusions

Whether the reason for inefficient arbitrage across the IFA is local congestion in northern France, the UK Climate Change Levy Exemptions, or the dominant behavior of Electricité de France, or more likely a mix of all three, it is apparent that expecting transparent market efficiency in the relationship of auction prices to energy spot market spreads is too ambitious. The sequential nature of the transmission capacity auctions and spot energy trading undermine the simple arbitrage relationship; the presence of obscure green supplements differentiates the commodity; and locational factors differentiate the cost of access to markets. Against this background, we suggest that it is quite difficult for regulatory authorities to monitor conduct. We observe that conduct can be an issue in these auctions, not just through capacity withholding, but through inefficient arbitrage with a dominant generator, under special circumstances, creating electricity flows from a high- to a low-price area. As the special circumstances of the analysis are satisfied in the case of the IFA, we provide evidence that such flow reversions do occur in reality. We also show that the dominant French generator is apparently exporting electricity to the UK, despite French prices appearing to be higher, while most other players trade in the opposite direction. There are several possible explanations, with the circumstantial appeal of market conduct being rather persuasive.

The total inefficiencies of under-using or misusing the IFA amounted to € 289 m over this four-year period. The largest share was due to intentional or accidental withholding. We were able to show that a significant amount of physical transmission rights (worth € 100 m in importing and € 65 m in exporting directions) was bought but neither used nor returned to the auctioneer. This is evidence that the use it or lose it principle is not properly applied in the IFA. Another source of inefficiencies – the lack of ex ante netting – had minor effects. Only 808 GWh importing capacity worth € 6.6 m and 816 GWh exporting capacity worth € 2.9 m could have been released by ex ante netting in the years 2002 to 2005.

Finally, we note that a substantial part of these inefficiencies occur because the energy and transmission markets are decoupled through the ex ante nature of the capacity auctions. Implicit auction approaches with nodal pricing and harmonized pricing of renewable power would preclude the inefficiencies we identify. However, these could also be achieved in an ex ante auction setting by enforcing the use it or lose it principle, allowing ex ante netting and increasing the number of traders. Thus, despite the vulnerability of explicit ex ante auctions to the inefficiencies we identify, they may be the most pragmatic method initially to implement interconnector trading. However, the design of the market mechanism, harmonization, monitoring and liquidity incentives requires careful thought and attention.

V.7 Appendix

Table 32: Aggregated company level nominations

	No. of export nominations	Total export nominations in MWh	Avg. export nomination in MWh	No. of import nominations	Total import nominations in MWh	Avg. import nomination in MWh
ACCE	8,686	1,267,968	146.0	5,504	847,178	153.9
ARON	2,137	167,835	78.5	59	3,595	60.9
AELE	771	70,719	91.7	24	2,132	88.8
AEPE	3,415	661,461	193.7	2,148	345,238	160.7
AXIE	10,668	2,067,320	193.8	5,482	1,259,711	229.8
BARB	8,313	1,650,806	198.6	4,291	913,155	212.8
BKWE	5,781	764,245	132.2	1,041	78,042	75.0
BHPB	0	0		12	612	51.0
BPGE	1,242	76,185	61.3	152	9,296	61.2
CARE	2	2	0.8	177	14,029	79.3
DUKE	100	4,900	49.0	48	3,060	63.8
DYNE	1,221	65,153	53.4	463	27,625	59.7
EDEF	14,193	6,606,480	465.5	3,378	725,144	214.7
ELEE	8,350	614,233	73.6	2,761	158,405	57.4
FHCE	462	36,957	80.0	280	24,868	88.8
INNE	6,331	551,856	87.2	3,914	390,220	99.7
GASE	3,377	248,941	73.7	290	19,192	66.2
LPAS	154	13,185	85.6	1,086	161,810	149.0
MSCG	0	0		586	24,398	41.6
PGEN	8,771	581,831	66.3	1,124	66,572	59.2
SEME	10,643	1,053,666	99.0	4,596	261,220	56.8
SETL	3,477	347,502	99.9	791	49,289	62.3
STAT	2,463	168,649	68.5	1,004	62,501	62.3
TFEE	12,791	3,145,247	245.9	4,056	883,895	217.9
TXUE	1,972	248,395	126.0	1,220	151,467	124.2
VATT	448	23,890	53.3	381	15,247	40.0
WILE	0	0		24	1,800	75.0

Figure 24: Comparison of UK over-the-counter and power exchange prices

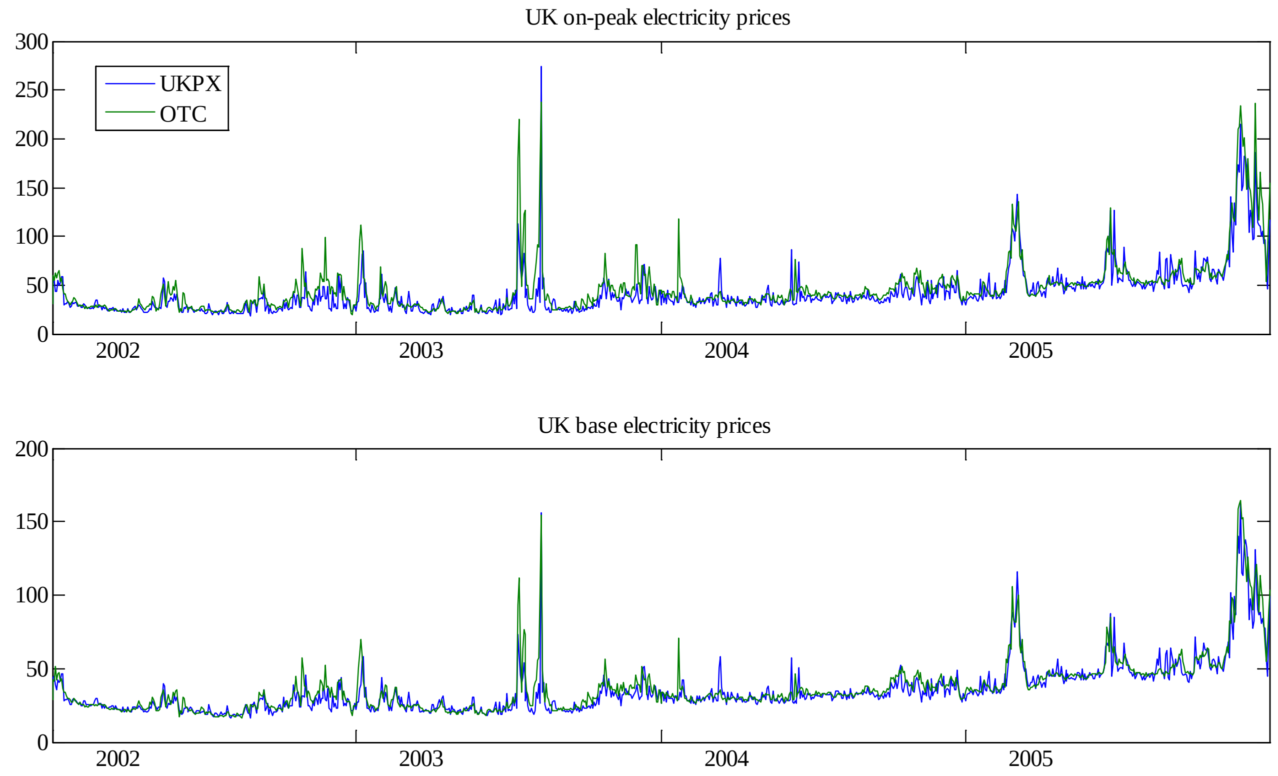

Table 33: Summary statistics

	Mean	Variance	Minimum	Maximum
PNX electricity price in the 3rd hour	19.4	77	0.5	66
PNX electricity price in the 13th hour	46.8	1,486	7.9	1,000.1
UKPX electricity price in the 3rd hour	25.4	96	5.2	86.7
UKPX electricity price in the 13th hour	45	785	19.3	399.3
Interconnector usage volumes in the 3rd hour	893.8	800,348	-1,541	2,000
Interconnector usage volumes in the 13th hour	160.3	1,105,163	-1,998	2,001

VI Outlook

The chief goal of this dissertation is to provide reliable empirical evidence for the discussion of imperfections in Europe's wholesale electricity markets. As pointed out in the last two chapters, inefficient cross-border trade and the potential exercise of market power weigh heavily on a successful outcome. With increased availability, quality and length of data series, it became feasible to empirically test a set of theoretically deduced or anecdotal hypotheses.[158] The novelty of the types of markets and their associated data required developing new approaches. Therefore, methods developed in other contexts were carefully adapted and applied to often high frequency (up to hourly) electricity market data.[159]

A Markov-Regime switching model was used to capture the non-linear interaction of electricity, fuel and emission allowance prices. Although used in this dissertation to study the differences in German and British price formation, the model may be helpful for risk management or forecasting purposes as well. The same holds true for the detection of asymmetric pass-through of emission costs to electricity prices. Further research should examine whether wholesale and retail electricity prices are also linked asymmetrically.

The study of European electricity price convergence provides an early "snapshot" of the markets' interaction. Day-ahead forecasting of arbitrage potentials using the Kalman Filter is of course not only suited to study the foregone arbitrage gains in the past, but can also be used in profitable cross-border arbitrage in the future. To better understand the price level interactions and the price shock dispersion in Europe, a shock dispersion model (possibly a structural Vector Autoregression) would be desirable. This could serve as input for improved cross-border hedging strategies.

The study of the Anglo-French electricity interconnector shows that cross-border trading strategies of generators, traders and consumers differ and that the exercise of market power in explicit auctions can be profitable. If market power mitigation through new netting rules or the introduction of implicit auctions fails, competitive traders should be made aware of the

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[158] Because most of the data were not readily available, this dissertation required collecting and preparing dozens of time series. I thank NordPool, the APX Group, EEX and National Grid for providing access to relevant data.

[159] All calculations were implemented and carried out in Matlab, and the corresponding code can be obtained from the author upon request.

fact that some companies’ behavior is not only driven by the observable price differentials. During our research the issue arose of cross-border trade impacts of national renewable energy support schemes. As the paragraph on the UK’s levy exemption certificates (p. 88) shows, the impacts these incentives have on international electricity flows are often difficult to predict. Empirically separating these effects could provide insights into the windfall gains and deadweight losses produced by such national policies in the developing common European electricity market.

Glossary and Abbreviations

A. Glossary

This glossary introduces the basic concepts of cross-border congestion management schemes. More detailed descriptions about some of the methods presented in this dissertation can be found in CONSENTEC (2004) and ETSO (2004).

“*base*”: 0am-12pm

“*explicit auctions*”: National electricity markets exist. The right to use transmission capacity is allocated in auctions.

“*first-come-first-served*”: National electricity markets exist. The right to use transmission capacity is allocated according to a waiting list.

“*implicit auctions*”: A super-national body collects the supply and demand curves in each country and allocates the cross-border transmission capacity to optimize welfare. (One country = one price)

“*netting*”: Flow nominations in opposite directions must be subtracted allowing the new net capacities being resold.

“*nodal pricing*”: A super-national body collects the supply and demand curves at each node and allocates the transmission capacity to optimize welfare. (One country = multiple prices)

“*off-peak*”: 8pm-8am

“*on-peak*”: 8am-8pm

“*pay-as-bid*”: The lowest accepted bid of an auction sets the price for all buyers.

“*pro-rata*”: National electricity markets exist. The right to use transmission capacity is allocated according to the share of individual desired capacity to total desired capacity (Who demands more receives more).

“*uniform pricing*”: The bidder must pay exactly the price for each bid as if it were successful.

“*use it or lose it*”: Physical transmission rights must be used or returned to ensure the absence of withholding.

B. Abbreviations

ADF	Augmented Dickey Fuller test for stationarity
ADL	Autoregressive Distributed Lag (model)
APX	Amsterdam Power Exchange (Netherlands)
ARA	Amsterdam - Rotterdam - Antwerp (Dutch market for coal)
ARCH	Autoregressive Conditional Heteroskedasticity
BSUoS	Balancing Services Use of System charges
CAR	Confirmation And Reallocation notice at the IFA
CCL	Climate Change Levy
CEPS	Czech System Operator
CHP	Combined Heat and Power plant
CO_2	Carbon Dioxide
COMECON	Council for Mutual Economic Assistance
CPP	Coal Power Plant
DKE	East Danish NordPool price area (Denmark)
DKW	West Danish NordPool price area (Denmark)
EC	European Community
ECM	Error Correction Model
EEX	European Energy Exchange, Leipzig (Germany)
EON	E.ON Netz
ETS	Emission Trading System
EU	European Union
EUA	EU Emission Allowance
EXAA	Energy Exchange Austria, Graz (Austria)
FOC	First Order Condition
HHI	Herfendale-Hirshman Index
IFA	Anglo-French electricity Interconnector
iid	Independent and identically-distributed
KPSS	Kwiatkowski, Phillips, Schmidt and Shin – test for stationarity
LEC	Levy Exemption Certificate
NAP	National Allocation Plan
NG	National Grid
OMEL	Operador del Mercado Ibérico de Energía, Madrid (Spain)
OTC	Over-The-Counter
OTE	Czech Market Operator, Prague (Czech Republic)
PCA	Principal Component Analysis
PNX	Powernext, Paris (France)
PPX	Polish Power Exchange, Warsaw (Poland)
PSE	Polish System Operator
RTE	Réseau de Transport d'Electricité
SMRC	Short run marginal cost
SWE	Swedish NordPool price area
TNUoS	Transmission Network Use of System charges
TSO	Transmission System Operator
TTF	Title Transfer Facility hub in the Netherlands
UK	United Kingdom
UKPX	UK Power Exchange, London (United Kingdom)
US	United States
VE-T	Vattenfall Europe Transmission
ZDT	Zonal Demand Tariff

C. Company names

1	ACCE - Accord Energy	10	CARE - Cargill PLC	19	MSCG - Morgan Stanley
2	ARON - J.Aron & Company	11	DUKE - Duke Energy International Ltd	20	PGEN E.ON UK plc
3	AELE – Aquila Energy Ltd (Npower Limited)	12	DYNE - Dynegy UK Ltd	21	SEME - Sempra Energy Europe Ltd
4	AEPE – AEP Energy Services Ltd	13	EDEF - Electricité de France Generation & Trading	22	SETL - Shell Energy Trading Limited
5	AXIE - Merrill Lynch Commodities LTD	14	ELEE - Electrabel SA	23	STAT - Statkraft Markets Gmbh
6	BARB - Barclays Bank plc	15	FHCE - First Hydro Company	24	TFEE - Total Gas & Power Ltd
7	BKWE - BKW FMB Energie AG	16	INNE - RWE nPOWER PLC	25	TXUE - TXU Europe Energy Trading BV
8	BHPB - BHP Billiton Marketing AG	17	GASE - Gaselys	26	VATT - Vattenfall AB
9	BPGE - BP Gas Marketing Limited	18	LPAS - El Paso Merchant Energy Europe	27	WILE - Williams Energy Europe

D. Units

m	million
bn	billion
£	Great British Pound
€	Euro
MW	Megawatt (1,000,000 Watt)
MWh	Megawatt hour (1,000,000 Watt hours)
GWh	Gigawatt hour (1,000,000,000 Watt hours)
TWh	Terawatt hour (1,000,000,000,000 Watt hours)
MWh_{el}	Megawatt hour of electric energy
MWh_{th}	Megawatt hour of thermal energy

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