Structure and Performance of Six European Wholesale Electricity Markets in 2003, 2004 and 2005

Executive Summary

Presented to DG Comp 26th February 2007

Prepared by London Economics in association with Global Energy Decisions

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1 Executive Summary

This chapter presents a summary of the report, including results, across the countries studied, namely Belgium (BE), Germany (DE), Spain (ES), France (FR), the Netherlands (NL), and Great Britain[1] (GB). The purpose is to give a high-level overview of the work carried out and to facilitate comparisons across countries for certain key elements. The chapter gives an overview of the study and presents summary key results for traditional market structural measures, electricity-specific measures of market structure, market outcome measures, and regression analysis. Significantly more discussion and results in relation to a number of sensitivity and alternative scenarios are contained in the detailed country specific chapters of the report.

1.1 Introduction, background, and overview

This report studies a selection of the EU's major electricity wholesale markets with the aim to determining how competitive markets were in the three years up to 2006.

The EU is in the midst of creating a fully competitive internal market for energy and electricity. There are concerns and doubts as to how much has been achieved along these lines. In 2005, the European Commission's DG Competition launched a sectoral inquiry into the European electricity and gas markets. The final report of the inquiry was published on 10 January 2007[2]. Among many findings made by the sector inquiry, the two main findings that concern this report were:

- Market concentration remains very high in a number of geographical and product markets; primarily national wholesale/generation markets.
- Large energy consumers doubt that prices on spot and forward wholesale markets result from fair competition.

[1] The market comprising England, Scotland and Wales (i.e. the United Kingdom without Northern Ireland).

[2] Further information on the sector inquiry, including its Final Report, are available at:

http://ec.europa.eu/competition/antitrust/others/sector_inquiries/energy/

The many findings of the final report, and especially the two findings above, suggest that competition in wholesale electricity generation is not functioning properly. While there is little overall informed dispute about the high levels of concentration in some EU countries (e.g., BE and FR), the reliability of traditional concentration measures as an indicator of market structure and market outcomes varies by situation, time, and in response to other factors such as interconnection. Determining how competitive electricity wholesale markets are is thus quite complex. Market concentration measures merely relying on market share may not give a good indication of how competitive electricity markets are likely to be. This provides the impetus for a more detailed study into the electricity markets using more innovative and advanced techniques.

Even more contentious (than the usefulness of market concentration as an indicator) are other issues, especially whether recent spot and wholesale prices are reflective of full and fair competition. This may be for a variety of reasons; but many of the reasons that make it difficult to determine if electricity prices are fair, flow from the physics of electricity. Electricity cannot be stored (cheaply); the transmission system must be balanced in real time; there are a vast variety of generation technologies, capital vintages, fuel types; trading occurs in many markets including spot, exchange, over-the-counter, to name just a few. These factors (and others) combine in complex ways to impact on cost, available capacity, and other factors, which interact in complex ways. The result is that observation of electricity prices and costs, without further in-depth study, can give sometimes little insight into how competitive electricity market outcomes have been.

The EU Commission, and the DG Competition in particular, therefore have been endeavouring to shed additional light on the above contentions, i.e., that current levels of concentration are leading, or are likely to lead, to poor market outcomes and that wholesale prices are not as keen as they could be.

In the course of these endeavours, the European Commission DG Competition (DG Comp) commissioned London Economics (LE) in association with Global Energy Decisions (GED) and Professors Natalia Fabra, Jean-Michel Glachant, and Nils-Hendrik M. von der Fehr to carry out an in depth and detailed study into the structure and functioning of the EU's electricity markets. The project was led by LE who formed a consortium specifically for the project. LE developed and proposed the methodology and ultimately analysed the results and drew conclusions. GED provided the software, despatch modelling, data, and a technical project coordinator. GED also ran the software and provided support on the software, including a specific applet for price calculation. The associated academic advisors, internationally recognised experts in EU electricity market competition economics, were asked to review the proposed methodology and key assumptions involved in the modelling and analysis, and propose alternatives if the methods undertaken were not consistent with recognised best practice in electricity competition economics. These experts agreed with the methodology and their comments were taken on board. The whole team, including the DG Comp project team, contributed to many parts of the project along the way, but the conclusions are ultimately LE's.

The study was to be a largely quantitative and fact-based assessment of market structure and market performance in selected European electricity markets and with the ultimate objective of uncovering the details any potential relationship between the two.

The study is unique in several ways, most significantly it is based on actual data returned by the generation companies and utilities on output, cost, and unit characteristics from the generation units. The study involved simulation of the electricity markets for the six countries and relating the simulations to market outcomes via econometric (statistical) techniques. While a complex subject (and many of the detailed results involve quite technical nuances of statistical and electricity despatch simulation modelling), we have endeavoured to present the results (especially in this chapter) as accessible as possible to a more general audience.

The study of this very difficult problem of relating electricity market structure to market outcomes (and uncovering evidence of either competitive or un-competitive market outcomes) requires the use of a detailed methodology. Our approach was therefore several-fold.

First, we investigated the more traditional structural measures of market concentration (those based on market shares) such as the concentration ratio and the Hirfindahl-Hirschmann index (HHI). Since market conditions in electricity markets can change hour-to-hour, season-to-season, year-to-year, we estimated these measures on an hourly basis over the 2003-2005 sample period. Forced outages, maintenance events and deratings, among other issues, are all accounted for in the calculation of the total capacity available to the market in each hour. Market shares were also calculated based on generation output. A number of sensitivities were also included to estimate the impacts of interconnectors, long-term contracts, and capacity reserved for system balancing commitments.

We next undertook to estimate electricity-specific measures of market structure, the residual supply index (RSI) and the pivotal supplier index (PSI). These measures, of how 'pivotal' a given supplier is, are designed to deal more effectively with the changing nature of electricity markets, and are calculated hourly.

The next element of the analysis was the calculation of market outcome measures. Lerner Indices (LI) and Price-Cost Mark-Ups (PCMU) were estimated as standard economic measures of the competitiveness of market outcomes. To calculate these measures first requires the estimation of the marginal cost of energy on the electricity grid for each hour of the 2003-05 sample period. To do this we used GED's Prosym™ [3] market despatch simulation model, with inputs on unit characteristics, fuel prices, thermal efficiency, planned and forced outages, available capacity, plus other relevant factors collected by DG Competition as part of the recent Sector Inquiry from the generators and transmission system operators (TSOs). This allowed for a simulation of the market, based on the actual generator data, of the optimal system despatch and resulting marginal cost.

[3] Nearly 200 companies worldwide (including many European generators, traders and TSOs) use the ProSym engine to do long term electricity price forecasting, conduct resource planning studies and optimize generation despatch.

The final element of our analysis was to relate the calculated market outcome measures to the electricity-specific market structure measures, the RSIs. This was done using econometric regression (statistical) analysis. The econometric approach is both useful and necessary as it allows one to control for many random factors (weather, temperatures, outages) and more economically benign factors (scarcity) can combine to raise prices and margins. These factors may have little to do with market power, and so thus must be controlled for. Controlling for random and deterministic variables was thus done via the econometric approach.

It is noteworthy, before going further, to highlight the scale and extent of our analysis, as well as the degree to which we believe we have advanced the debate and state of knowledge of the electricity sector in the EU's major markets. The study involved data collection and analysis on a scale that, to our knowledge, is unprecedented in the electricity-economics field globally. The study involved the hourly observation, simulation, and relating to price outcomes of output and marginal cost, and market structure for almost every generation unit in every hour (8,760 hours/year and 8,784 in 2004) for three years ((8,760x3)+24=26,304) for six countries (x6=157,824). With countries having between 60 to over 350 units, and over 25 variables either collected or estimated, the study involved the collection of about 500 million data points and manipulation and analysis of close to 1 billion data points, and resulting in an approximate total of 75GB of data inputs and outputs. Further, while previous studies have looked at market outcome measures in selected markets in the USA, and also related the RSI to price cost margins, no study to our knowledge has comprehensively related market structure measures and market outcome measures in a manner similar to that advanced in this report. Previous studies either focused on a single country, a limited time period, or did not account for many factors. Thus, our multiple regression results can be seen as groundbreaking.

In the course of this study and as part of the wider sector inquiry, the DG Comp and the LE team have undertaken to collect a very large amount of data from the electricity generators in the EU. Data has been collected on a great number of electricity market details, including; unit characteristics and operational details (installed capacity, thermal efficiency, planned and forced outages, flexibility in coming online), outputs (total generation), costs (running cost, fuel costs, fuel prices paid, operational costs), as well as contractual obligations (long-term contracts and system balancing commitments), in relation to almost all companies and generation units in the six countries studied. These data were necessary for, above all, the simulation of the electricity markets. We acknowledge the efforts and cooperation of the EU generators in the study and the collection of these data by the DG Comp team throughout the course of the study. We also note that the utmost confidentiality of the data was maintained through the most rigorous procedures[4].

Finally, the results of our extensive analysis present a detailed assessment of the structure and outcomes of the EU six electricity markets studied, as well as an investigation of the structure-outcome relationship. However, our analysis is still not without limitations. Ultimately, our analysis supports the two key points of the sector inquiry report; namely, that the current market structure in the EU electricity markets (the six markets studied) in a significant number of hours is likely to be conducive to anticompetitive behaviour. And secondly, that price outcomes on the EU wholesale electricity markets may have been less keen, than they otherwise would have been, had the markets been structured more competitively. The general caveat of the analysis is that uncontrolled for factors may have caused the appearance of market power, and that the existence of market power is not necessarily evidence of its abuse. However, our regression results have controlled for a great number of factors.

We turn now to a summary of the methodology and of the results; summary conclusions end this chapter.

[4] All data from the generators was processed and analysed on site at the DG Competition in a locked data room on designated laptops without internet or outside access to the room or data. Company names were anonymised as appropriate during the exercise and for the report.

1.2 Overview of methodology and data

1.2.1 Methodology adopted

Electricity as a commodity has many special features, and thus analysis of electricity market competition is more complex than other markets. Among the most important are that it is generally difficult/costly to store. It can be shipped but only on the HT transmission system (which can be congested); and supply and demand must be matched on the system within very tight margins in real time. Electricity market interactions can also involve complex commercial bidding strategies. Finally, random factors like weather and outages impact supply and demand. The special features of electricity markets suggest that standard tools of competition analysis should be used in concert with measures designed specifically for electricity market analysis. Further, more advanced techniques such as regression analysis are required to relate market structure and market outcomes and control for random error.

HHI and CRn

Our analysis first focused on the standard tools of competition economists and competitions authorities such as Herfindahl-Hirschman Indices (HHI) and concentration measures (CR(n)). In the context of electricity markets it is important to make use of detailed data and modelling. Thus our analysis involved adjusting the measures to account for hourly changes in capacity of the system and market shares of players: despatch changes, as market conditions (e.g., hydrological, fuel prices, etc) change, as players take planned maintenance outages, schedule outages, forced outages and as plants run for reliability-must-run conditions, as well an many other factors.

Another important issue is market definition. The analysis and modelling considers the relevant geographic market to be the wholesale generation market within a particular country, with each country assessed seperately. Therefore, the role of interconnectors[5] is limited to a sensitivity analysis carried out for each of the markets to assess the potential impact of interconnector linkages with neighbouring countries on the degree of concentration in a particular market.

[5] We did not have data allocating actual flows or capacity reservations to companies.

HHI and CR(n) measures were constructed for a selected number of capacity measures (MW), as well as generation output (MWh).

Electricity-specific market structure indicators: RSI and PSI

Standard concentration measures based on market share may still be insufficient as indicators of market power in electricity markets. If capacity is tight relative to demand, even a small firm could exercise market power, while if capacity is in excess relative to demand, even a large firm might typically have to engage in tough price competition. In light of the difficulties with standard market structure measures, electricity-specific market structure indicators, namely the Residual Supply Index (RSI) and the Pivotal Supplier Index (PSI), were estimated to account for the specificities of electricity markets. Rather than focussing on market shares of the companies, as is the case with the traditional concentration measures, these measures identify the indispensability (or 'pivotalness') of companies to meeting the hourly demand on the system. The more indispensable/pivotal a company is the more market power that company is considered to have.

At the most basic level the PSI answers the question as to whether a company can be considered to be pivotal to meeting demand in a particular hour. A company is considered pivotal if the available capacity capable of being supplied to the market, less the available capacity of the company of interest is less than demand in that hour, then that company's involvement in the market is necessary to meeting demand.

The RSI is a generalised continuous form of the PSI. The RSI calculates the indispensability of a specific company relative to the load in the particular hour and thus provides for a continuous measure of market power. Therefore, with the RSI one not only determines whether a company is indispensable in a given hour but also one can assess the degree to which the market is relying on this company's available capacity to meet demand.

Market outcomes: price cost margins

To assess market outcomes we estimated price cost margins[6]. This approach is regularly applied by competition economists and competition authorities and has previously been applied to electricity markets. Lerner Indices (LI) and Price-Cost Mark-ups (PCMU) were both calculated to assess the relative difference between price and cost and as such allow for an assessment of the likely competitive nature of the market that produced the result. The calculation of both measures allows for a direct comparison with results found previously in other studies, which may have only applied a single methodology to calculating market outcome measures. The Lerner Index (LI) relates the difference between price and cost to the price in the market, whereas the Price-Cost Mark-up (PCMU) relates the price cost differential to the cost, where the cost is the marginal cost of the system in both cases[7].

[6] These are the margins of the market exchange price of each country over the estimated system marginal cost in each county. These were calculated hourly for each country. The system marginal cost is the estimate of the perfectly competitive price. Thus, market price above the perfectly competitive price estimate is an estimate of how competitive markets have been.

[7] It may facilitate one's understanding of these measures if one keeps in mind that the value of both the Lerner Index and the Price-Cost Mark-up in a perfectly competitive market is zero, as in a perfectly competitive market price equals marginal cost.

In order to calculate market outcome measures, one first requires an estimate of the marginal cost of the system. In electricity markets, due to demand variations, marginal costs are likely to change on an hourly basis. To estimate hourly marginal cost for the system, one that reflects the system's technical characteristics and dynamic constraints on plants, each of the six electricity markets were modelled separately[8] using GED's Prosym software—a state-of-the-art dynamic electricity market simulation package.

This approach yielded an optimal system despatch, subject to system constraints and dynamic constraints on plants, and an estimated marginal cost. The marginal cost returned by the model was obtained by applying the Marginal Average Cost approach in MARKETSYM. Under this approach the model simulates the cost-minimizing commitment and despatch to serve loads. Hourly generation and generation cost values for each station in the model are reported and the system marginal cost equals the fuel cost of the highest per MWh unit producing in each hour, albeit with some exceptions. In estimating the system marginal cost, some stations were excluded from setting the price as they are not truly marginal. Stations were excluded from the ability to set price by prior specification based on the information provided by the companies. Primarily, these units were stations that are specified as Must Run, as these units are forced to run out-of-merit operations, and units that have simulated generating levels at their reported minimum stable generation level[9] . Of the remaining units, the unit(s) with the highest average cost, in each hour, is identified as marginal; their average costs is the system Marginal Average Cost.

Start costs[10] were excluded as they were determined to be small, between 0.1 and 0.2% of average fuel costs in each market.

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[8] Importantly, the model takes into account imports and exports which effectively took place during the period. It means in particular that, whenever a market was exporting (this is especially true for France and Germany), the effect of price increases created by the exports which took place during the period has been factored in by the model.

[9] Units at minimum stable generation in the simulation are units forced to run out-of-merit operations in the simulation such as some Combined Heat and Power stations which are not economic to run only for electricity purposes or plants called in to serve reserve purposes in the simulation.

[10] Generators typically incur a fuel cost to start their units. For some units, this can be significant.

The result of the modelling was to produce, on an hourly basis, an optimal system despatch and hourly marginal cost for each of the six markets. This marginal cost was used in all of the outcome measures.

The price chosen to relate to the modelled marginal cost is also of fundamental importance to the result of the analysis. In order for a set of hourly prices to be deemed representative of the market and the prevailing market conditions, it is important for these prices to adjust to market conditions. During periods of relative scarcity of available installed capacity, associated with periods of peak demand under normal conditions, one would expect to observe higher prices. Therefore, it is important for this purpose to use a price series that includes sufficient detail and variation to reflect the market and its likelihood for change on an hourly basis. Prices from day-ahead electricity exchanges were assessed and found to reflect required criteria and therefore were used: APX (NL), EEX (DE), PowerNext (FR), OMEL (ES), and UKPX (GB). No such price was available for Belgium[11]. Electricity market assessment prices from Platts were also used as a check in all markets.

1.2.1.1 Relating the outcomes to market structure

A primary goal of the analysis was to assess how market structure impacts on competitive outcomes. Since electricity-specific structural indicators of RSI and outcome measures (price cost margins) were calculated hourly for three years, a further and more general aspect of competition in electricity markets could also be assessed; the link between the structure and outcomes of the market. One would expect to see decreases in the RSI value (indicating an increase in indispensability of the relevant company and thus an increase in their market power) to be correlated with an increase in the margin or mark-up earned in the market. An assessment of this relationship was undertaken through the use of econometric analysis.

[11] In Belgium, the BPI is a daily price for which both price and quantity are set by the largest operator. See the Belgium chapter for details.

The optimal despatch modelling has also allowed us to calculate a number of additional variables. The results of the GED modelling of each system have allowed for a detailed assessment of the economic cost of carbon since the introduction of the EU ETS in 2005. It has also allowed one to compare the actual despatch with the results of the modelled optimal despatch for each unit. It furthermore enabled us to calculate an estimated contribution to fixed cost by company. This was mainly performed as a model check, to show that the estimated competitive price (the optimal system marginal cost estimates) were not so low that generators would not earn substantial sums towards there past investments.

1.2.2 Data description

A major and unprecedented element of this study was the extent and coverage of the data. The data for this study was largely taken from a DG Comp database of responses to the questionnaires sent as part of the Sector Inquiry into electricity markets. This database provided, for the purpose of the measures and indicators calculated, all[12] of the unit-specific data used for each company included in the study. The highest levels of confidentiality were maintained throughout. Crosschecks using GED's European database and other public sources were also performed.

At the most basic level the data provided in response to the sector inquiry questionnaires included the name, location and owner[13] of each generation unit, for the period January 2003 to December 2005. Data are included on the normal maximum operating capacity (MW) and technical characteristics of each unit greater than 25MW. Units below 25MW were aggregated by technology. Hence, the simulation took into account virtually all plants relevant for the price-formation mechanism.

[12] There were of course occasional problems with missing or inconsistent data. This was either rectified with further questionnaires, resorting to public data, or other assumptions. Details are in the chapters and annexes.

[13] In the case of co-owned units, the ownership share of the company was provided.

The output of each listed unit was provided as the hourly net electrical production (MWh) to be transported to the high voltage grid. These data were analysed on a unit-by-unit basis in order to address issues such as daylight-savings time, missing data points and inconsistent data points (generation far in excess of the normal maximum operating capacity, incorrect unit of measurement applied), which could affect the relative consistency of the series. This process resulted in 26,304 hourly observations on the net electrical production of all units greater than 25MW and a similar number of observations for smaller units, less than 25MW, aggregated by company and technology type.

The planned and actual maintenance schedules of each unit has also been provided, and thus planned and forced outages were included in the database and incorporated into concentration measures and the despatch modelling.

Data on the heat rate (GJ/MWh) of each unit were provided by companies. From this data standard heat rate curves were derived based on technological profile and reference to GED's worldwide database of plant performance data. The average monthly cost of fuel (€/GJ) for each unit was also provided.

The TSOs provided information on the interconnector links of each system, capacities (MW) and flows (MWh). This data was not company-specific, however, thus preventing an analysis of the reservation and use of capacity over interconnectors as part of this report.

Data on power prices were taken from the following day-ahead power exchange markets in each of the countries;

- Belgium – Belgian Power Index, an index reported by Electrabel of daily prices of electricity it has agreed to buy and sell with counterparties.
- France – Powernext day-ahead hourly price series.
- Germany – European Power Exchange (EEX) day-ahead hourly price series.
- Netherlands – Amsterdam Power Exchange (APX) day-ahead hourly price series.
- Spain - Compañía Operadora del Mercado Español de Electricidad, S.A. (OMEL) day-ahead hourly price series.
- Great Britain – UK Power Exchange (UKPX) hourly price series.

The marginal cost used in the calculation of the outcome measures in the country-specific chapters of the report are the result of the GED modelling of the optimal despatch of the systems. The hourly returned marginal cost on the system reflects the average generating cost of the most expensive generating unit (€/MWh), excluding those units whose generation is constrained. In the modelling scenarios for 2005 where CO_2 emission allowances were fully factored in, the data on the cost of CO_2 was taken from the EEX and applied in all countries, while the basic emission rates of units, (data that was not readily available), was based on a benchmarking exercise undertaken by GED. Individual units with known emission rates were compared with the interpolated emission rates assigned and were seen to compare favourable with the benchmark approach in all cases. Further discussion of this is contained in the report and the Appendices.

1.3 Results

1.3.1 Summary of CR(*n*) and HHI

The first part of our analysis calculated concentration ratios and HHIs on an hourly basis. The market shares, which form the basis of these market structure indicators, were calculated based on both capacity and generation bases. Results for the HHI across countries show large contrasts.

Table 1.1 below shows the traditional measure of market concentration for each country. These are average figures based on hourly market shares based on market shares formed on an available installed capacity basis.

Table 1.1: CR(*n*) and HHI average across countries

Country	CR(*n*)[14]	HHI
BE Belgium	90.7%	8,307
DE Germany	54.1%	1,914
ES Spain	71.4%	2,790
FR France	92.6%	8,592
NL Netherlands	57.7%	2,332
GB Great Britain	32.6%	1,068

Source: LE

The respective chapters provide histograms of the CR(n) and HHI values to show the impact of hourly variations.

14 The number of companies for the CR(*n*) calculation is different for each country. This is because the concentration ratio of say the biggest company in FR and BE already raised the concentration to a very high level. Therefore, BE and FR, *n*=1, Spain and NL *n*=2, and DE and UK *n*=2.

The cross-country results with sensitivities showed that some countries are highly concentrated (BE and FR), some countries range from moderately concentrated to highly concentrated (DE, ES and NL), and GB ranges from borderline unconcentrated to moderately concentrated[15]. There is some variation over time and by sensitivities. Many sensitivities were carried out[16], but in general, the qualitative conclusions were not sensitive to the changes in assumptions about market definition and how market shares were formed, with the main exception being the impact of interconnection in the Netherlands.

[15] Commonly used but somewhat arbitrary thresholds are: HHI< 1000; unconcentrated; 1000<HHI<1800; moderately concentrated; HHI>1800, highly concentrated.

[16] For more details see the individual country reports.

1.3.2 Market Outcome Measures

Our analysis also calculated price cost margins for each country where relevant or possible[17] using both the price-cost mark-up (PCMU) and the Lerner Index (LI). Results on the calculated PCMU in each market are presented in Table 1.2. We note that the results for Belgium and France are not reported as they come with a strong caveat[18], (as does their comparison with other countries).

[17] This was not done for BE. Our opinion was that the BPI was not a relevant comparator with which to calculate margins as it is not an hourly exchange traded price. It further was found not to be related to scarcity, and its quantity and price are set by the largest operator in the market. The price is not likely to reflect market conditions. Margins for Belgium are indicative only. We also found it useful to breakdown the Belgian price to include the cost of carbon.

[18] In France, the first issue that arose was that reported total available capacities for many nuclear plants were substantially higher than the maximum actual generation over substantial periods of time for many such plants. This led the simulation model most likely to under-estimate the marginal cost in France, as nuclear is generally a very low marginal cost technology, with high capital costs. The reality of this apparent data discrepancy could be either explained by technical reasons on the operations of nuclear plant or by some other less benign explanations (see the chapter of France for more details). We could not resolve the issue further. The second issue was the amortisation of fixed costs in the context of the particularly flat merit curve of France: we lacked data to address that further issue. All in all, we judged the marginal cost results for France to be less reliable than other countries. In Belgium, the difficulty with the data was that an economically meaningful and hourly marginal or exchange price did not exist over the sample period. It was therefore our opinion that estimating hourly price cost margins for Belgium could not be done on a comparable footing relative to the other countries.

Table 1.2: Price Cost Margins				
Period	**2003-05**	**2003**	**2004**	**2005**
Including carbon cost based on weighted averages of GED SMC & Exchange prices				
Germany	27%	59%	22%	15%
Spain	21%	26%	5%	28%
Netherlands	6%	33%	-2%	-5%
Great Britain	11%	NA	4%	13%
Excluding carbon cost based on weighted averages of GED SMC & Exchange prices				
Germany	51%	59%	22%	72%
Spain	35%	26%	5%	66%
Netherlands	14%	33%	-2%	13%
Great Britain	31%	-	4%	42%
Source: LE				

The cross-country comparison shows a variety of margins[19] across countries and time. On average the lowest margins are in the GB and the Netherlands (11% and 6% respectively). Germany and Spain have the highest and second highest margins on average about 27% and 21% respectively. Negative margins in the Netherlands are likely a result from CHP and other thermal units (including Must-Run units) producing in reality more (to serve heat or must-run purposes and thus "dumping" such electricity on the market) than what could be assessed from the data supplied by the generators[20]. Also, in Great Britain in 2005, margins may have been overestimated due to the fact that very high gas prices might have given the incentive to generators to sell their gas rather than generate. The opportunity cost of such sales was not modelled (and thus not reflected in the cost), as we relied on the reported fuel costs. These results are broadly in line with what one might expect given the results of the concentration measures, HHI and CR(n).

[19] We note that the margins presented here are the margins of the load weighted-average of the price and cost, with the weights being formed by the share of total annual load reported in each hour.

[20] See chapter on the Netherlands for more details.

One can easily assess the impact of the introduction of the EU ETS on the PCMU values in these markets from the table above. For 2005, we ran a scenario "with carbon" (whose results are shown in the first part of the table above) and a scenario "without carbon" (whose results are shown in the second part of the table above). In the scenario "with carbon", the cost of a given plant includes the value of carbon for that plant whereas in the scenario "without carbon", the cost of the plant does not include the value of carbon. The value of carbon for a given plant (per MWh) is estimated by multiplying the carbon emissions of that plant (tonne/MWh) by the value of a tonne of carbon (€/t), as provided by the market of CO_2 allowances. Each scenario ("with carbon" and "without carbon") led to a marginal cost of the system in each hour[21] and the impact of ETS is equal to the difference between those two marginal costs[22]. . From the table, it can be seen that without carbon, all countries studied had significant margins above cost. Even with carbon fully priced in, only the Netherlands did not have substantial margins. The presence of carbon changes the rank order of the countries' margins in 2005. Germany had the highest margins without carbon, while Spain had the highest margins with carbon. This is a function of the carbon intensity of the technologies in the countries.

1.3.3 Breakdown of power price including margin, fuel cost and carbon

The discussion above in the immediately preceding section discusses margins. We now turn to the total breakdown of the exchange price into its constituent parts, including carbon pricing/marginal cost impact[23]. Table 1.3 presents annual load weighted values of each of these variables.

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[21] A different unit may set the price in each scenario.

[22] Please note that this is the maximum possible impact of ETS as the scenario "with carbon" relies on the assumption that companies fully price in the value of CO_2 allowances. It is unclear how far electricity generators have explicitly factored in the prices of CO_2 allowances into their electricity prices and to which extent they should be allowed to do so from a policy perspective. In a pending German competition case regarding this issue, the Bundeskartellamt judges that at maximum 25% of the costs for CO_2 certificates should be factored in.

[23] In this section, we present France and Belgium along with the other four countries. But we recall the caveat that direct comparisons across countries' margins should be made with extreme caution.

Table 1.3: Contribution to Power Price (€/MWh)			
Country	**2003**	**2004**	**2005**
BE Belgium[24]			
Sys Modelled MC	€ 29.75	€ 31.70	€ 50.40
Carbon	€ 0.00	€ 0.00	€ 10.11
Mark-Up	€ 11.31	-€ 0.70	-€ 10.23
Total	€ 41.06	€ 31.00	€ 50.28
BE INDEX Price	€ 41.06	€ 31.00	€ 50.28
DE Germany			
Sys Modelled MC	€ 19.46	€ 24.27	€ 28.17
Carbon	€ 0.00	€ 0.00	€ 13.86
Mark-Up	€ 11.42	€ 5.36	€ 6.39
Total	€ 30.88	€ 29.63	€ 48.42
EEX Price	€ 30.88	€ 29.63	€ 48.42
ES Spain			
Sys Modelled MC	€ 23.95	€ 27.51	€ 33.65
Carbon	€ 0.00	€ 0.00	€ 10.12
Mark-Up	€ 6.29	€ 1.39	€ 12.20
Total	€ 30.24	€ 28.89	€ 55.97
OMEL Price	€ 30.24	€ 28.89	€ 55.97
FR France			
Sys Modelled MC	€ 11.09	€ 12.92	€ 15.63
Carbon	€ 0.00	€ 0.00	€ 3.65
Mark-Up	€ 18.96	€ 15.98	€ 28.85
Total	€ 30.05	€ 28.90	€ 48.13
POWERNEXT Price	€ 30.05	€ 28.90	€ 48.13
NL Netherlands			
Sys Modelled MC	€ 36.26	€ 34.64	€ 50.50
Carbon	€ 0.00	€ 0.00	€ 9.52
Mark-Up	€ 11.99	-€ 0.63	-€ 3.09
Total	€ 48.24	€ 34.01	€ 56.93
APX Price	€ 48.24	€ 34.01	€ 56.93

[24] We have included Belgium and France in this case because we felt it was worthwhile to document the estimated impacts of carbon. Please recall the previous (footnoted) caveat of the comparison of Belgian and French margins to the others; The French data on nuclear plants (availability, costs) raised several issues; the Belgian prices, the BPI and the Platts prices were not sufficiently detailed nor sufficiently related to hourly supply and demand outcomes and scarcity for explicit analysis of the margins.

Table 1.3: Contribution to Power Price (€/MWh) (Continued)			
Country	**2003**	**2004**	**2005**
GB/Great Britain[25]			
Sys Modelled MC	-	€ 33.33	€ 39.06
Carbon	-	€ 0.00	€ 10.00
Mark-Up	-	€ 1.25	€ 6.35
Total	-	€ 34.58	€ 55.41
UKPX Price	-	€ 34.58	€ 55.41

Note: all values in this table are load weighted average values.

Source: LE

From the data in the table, one first notices a range of values in the marginal impact of carbon, from €3.65 to €13.86. This result is largely in accordance with what one would expect given the different generation portfolios of each of the countries concerned. The carbon impact was estimated by taking the emissions of the marginal plant in each hour (based on generation, efficiency and fuel type) and multiplying by the market price of carbon. In terms of cost, the marginal impact of carbon depends on how much carbon intensive technology was on the margin in each hour in any particular market, as well as its thermal efficiency. Therefore, the impact of carbon on France's estimated marginal cost is low (weighted average €3.65/MWh). This is because technology in France tends to be less carbon intensive[26]. The carbon intensity of nuclear and hydro (prevalent in France) is zero. Conversely, for countries such as the UK and Germany where coal and gas are the marginal plant in many hours, these are carbon intensive technologies (and likely, the marginal plants will have lower than average thermal efficiency), the impact is more pronounced. In these cases, the marginal impact of carbon in 2005 is substantial—Germany having the highest cost of carbon at €13.86/MWh.

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[25] Hourly price data from the UKPX is only available from July 2004 onwards. Therefore, there is no result for 2003 under this approach and the result for 2004 should be viewed in the light of the data availability issue.

[26] Nuclear is setting the price in a significant number of hours in the modelled optimal despatch. This is effectively because pumped storage was modelled by subtracting its energy from the estimate of demand.

We also see a variety of margins. Some countries, such as the Netherlands, show an average negative margin in 2004 and 2005 (recall this is mostly due to CHP and other plant not shutting down and operating out-of-merit). Others, such as France show quite high margins (over 100%-although a strong caveat once again applies; in addition, the fixed cost of nuclear would require higher margins). Note here, the margins as calculated are including carbon at full market cost (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment), this therefore represents a somewhat conservative approach to 2005.

It is possible that recent prices in the power exchanges studied are not reflective of the opportunity cost of carbon, since companies received their emissions trading allowances free. In this case, the mark-ups presented above would be higher. Whether companies' *should* price in carbon fully is another question, which we did not address.

1.3.4 Contribution to fixed cost

In addition to estimating the price cost margins, we also estimated the total value by country (DE, ES, NL, and GB)[27], by company and by year of the contributions to fixed cost. This figure is found by multiplying the quantity each unit produces under an optimal despatch by the difference between the estimated modelled system marginal cost and the average fuel cost of the unit, as reported[28]. The sum over each company's units in every hour is then the annual total. This was mainly done as a crosscheck of the credibility of the marginal cost estimates. The rationale was to check whether the estimated marginal cost from the optimal despatch was credible as a perfectly competitive price such that it would still allow substantial contributions to fixed costs[29]. The ability of companies to contribute to and cover fixed costs is a strong determinant on future investment decisions in the sector, as well as on the sustainability of current operations for individual companies.

These figures are found in Table 1.4 for the top 4 companies in each country. We note that all of the top four companies in the largest markets (DE, ES, and GB) and the largest (by this measure) company in the NL would have earned (had they traded all their power at the simulated competitive price) contributions to their fixed costs in excess of a billion euro over the three-year period. The smaller companies in the Netherlands each would have earned a little more or less than €500m.

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27 As we did not estimate regressions for France and Belgium and the reliability of margin estimates for these countries must come with a strong caveat, we did not estimate fixed cost contribution figures for these countries either.

28 Algebraically, this can be represented by; $CFC = Q^{m}_{i}x(SMC - AC_{i}))$; where CFC is contribution to fixed cost, $Q^{m}_{i\,s}$ is electricity generated by operators M and plant i and SMC is system marginal cost and AC_{i} are the average costs for plant i.

29 These calculations were not meant as a study of the investment decisions or incentives for investment in each country. This was beyond the scope of this study.

This analysis is useful in that it highlights a number of factors. The analysis indicates that the estimated competitive prices/marginal cost estimates are not generally so low that companies would not earn an operating profit[30]. It also suggests a consistency with the incentive to invest, but this result is merely indicative, as one should note that investment decisions should be analysed on a more micro basis.

Furthermore, one should note that for existing market participants, a substantial proportion of their portfolio is likely to be partially or fully amortised already thus reducing the need to cover such costs.

[30] Further analysis shows that on a per MW basis, these numbers are in light with the amortized cost of a generic new entrant for all countries studied except Spain. We note that there will be a variety of vintages of capital stock, and so this represents a relatively high hurdle in terms of the fixed costs needed for commercial operations.

Table 1.4: Contribution to Fixed Costs for largest companies (€'000)				
Company	**2003**	**2004**	**2005**	**Total**
DE Germany				
1338-S-DE	1,818,142.0	2,521,370.0	2,782,871.0	*7,122,383.0*
0436-S-DE	1,761,631.0	2,094,008.0	3,084,305.0	*6,939,944.0*
1681-S-DE	784,310.1	1,078,262.0	1,227,499.0	*3,090,071.1*
0569-S-DE	635,197.4	817,859.9	1,358,937.0	*2,811,994.3*
ES Spain				
0577-S-ES	853,472.1	1,029,273.0	1,394,689.0	*3,277,434.1*
0875-S-ES	387,150.9	580,013.1	671,181.4	*1,638,345.4*
1646-S-ES	110,710.3	183,125.7	351,760.2	*645,596.2*
0850-S-ES	135,484.0	121,964.2	126,943.5	*384,391.7*
NL Netherlands				
0712-S-NL	375,394.9	251,917.0	633,023.8	1,260,335.7
0511-S-NL	256,825.5	211,884.0	142,804.9	611,514.4
1193-S-NL	223,846.0	166,949.7	286,358.6	677,154.3
0439-S-NL	210,725.3	149,863.3	79,092.7	439,681.3
GB Great Britain				
0242-S-GB	1,706,199.0	1,808,226.0	2,995,477.0	*6,509,902.0*
0453-S-GB	606,512.1	643,986.9	685,716.3	*1,936,215.3*
1340-S-GB	422,153.5	448,385.1	732,872.3	*1,603,410.9*
1477-S-GB	326,060.2	451,280.3	375,499.3	*1,152,839.8*

Source: LE

1.3.5 Electricity-specific measures of market structure: RSI for top companies

Our analysis also included estimating electricity market specific measures of market structure. These measures included the residual supply index (RSI) and the pivotal supplier index (PSI) in relation to the biggest two to four firms in each country. These indicators are electricity-specific indicators used to give a richer measure of market structure in electricity markets than standard concentration measures. They measure the degree to which an individual supplier is 'pivotal' and thus required to meet demand. If a supplier is pivotal, it is hypothesized that they have the power to raise price unilaterally and profitably. The RSI is a continuous measure of pivotalness and the PSI is a zero-one measure. An RSI<110% indicates the supplier is near pivotal in that hour[31]. The summary results across countries for the RSI are contained in Table 1.5.

The results (in % of hours RSI<110%) show a wide range across countries, as well as across companies within a country. The result of comparing the RSI measures across countries shows some suppliers are indispensable (required to meet demand) in all hours. In the most concentrated countries, some suppliers are near pivotal or close to being required to meet load in up to 100% of hours. In other countries, such as GB, the number of hours is less than 5% that any of the top companies are in breach of the threshold and therefore determined to be indispensable to meeting the load. Finally, it is noteworthy that for both Spain and Germany, only two of the top four suppliers are seen to be pivotal in a large percentage of hours.

[31] One should note that this threshold value is not the result of a rigorous assessment of the suitability of such a value to each market but rather represents a broad guiding principle rather than a steadfast rule on indispensability based on studies previously carried out in California by the CAISO.

Table 1.5: Summary of country RSIs for largest companies (2003-2005)		
Country	**Company**	**% hours RSI<110%**
BE Belgium	0513-S-BE	100.0%
	1469-S-BE	5.0%
DE Germany	0436-S-DE	47.7%
	0569-S-DE	4.6%
	1338-S-DE	77.1%
	1681-S-DE	3.8%
ES Spain	0577-S-ES	41.1%
	0850-S-ES	0.0%
	0875-S-ES	49.2%
	1646-S-ES	0.6%
FR France	0340-S-FR	0.5%
	0472-S-FR	100.0%
	1449-S-FR	0.0%
NL Netherlands	0439-S-NL	3.5%
	0511-S-NL	32.8%
	0712-S-NL	44.6%
	1193-S-NL	22.7%
GB Great Britain	0242-S-GB	1.2%
	0453-S-GB	1.7%
	1340-S-GB	1.2%
	1477-S-GB	2.3%
Source: LE		

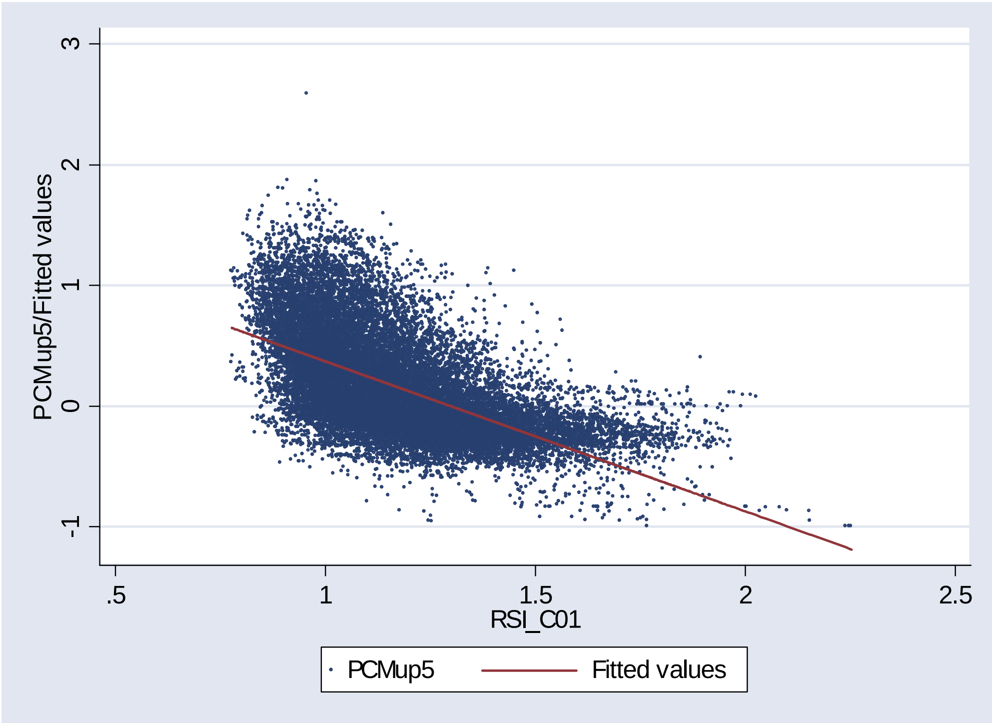
1.3.6 Regression analysis

1.3.6.1 Single variable models

The next and more groundbreaking part of our analysis was the regression or econometric analysis of the relationship between market structure variables to market outcomes, while controlling for random error and other factors. This is a test of the hypothesis that firms that are pivotal have market power. We estimated the impact of market structure on both market outcome measures (PCMU and LI). For this reason, we undertook regression analysis of PCMU and LI on RSI. Given the RSI is a continuous variable of the pivotalness of an individual operator measured hourly, it can be seen as a suitable candidate explanatory variable for the price cost margin using regression analysis[32]. We started this with simple (single explanatory variable) regression analysis—by regressing the price cost mark up on the RSI relative to the largest companies in each market. A graphical depiction of the results from the estimation of one of the specified simple regression equations is presented in Figure 1.1.

[32] Previous studies have used the HHI as the measure of market structure in regression analysis in electricity markets but the variable has been found to perform poorly and is generally not considered to be appropriate to such analysis.

Figure 1.1: Estimated impact of RSI on margins: Spain



Source: LE

The figure represents the estimated impact of the RSI for company 0577-S-ES on the price-cost mark-up in Spain for the full sample period. The line represents the predicted value, while the blue points the actual outcomes. Deviations from the line are thus modelled as random error. The results of all the univariate regressions are presented in the table below for the regressions of PCMU on RSI[33].

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[33] The results from the table above are the marginal impacts of RSI on the price cost mark up. The RSI is a measure that is near one when a large supplier is exactly pivotal. So a coefficient estimate of –1 would mean that essentially a 1% change in the RSI would lead to a 1% change in the price cost margin (mark up). The expected sign is negative, since more capacity means the market is less tight, and thus the RSI will rise, and margins would then be expected to fall. The t-values are the test statistic for regression coefficients. The t-statistics are all statistically significant for each RSI coefficient and for each company and country. The R-squared values range from about 11% to 35%, which is a reasonable fit for this type (single explanatory variable) of regression. The significance of the single variable regression models can be interpreted as follows: there is a near zero percent chance that the margins are not related to the RSI variables, even when not holding other factors constant.

Table 1.6: Regression results relating margins (PCMU) to market structure (RSI) for largest generators

Company-Country	Variable Name	Coefficient	Std. Err.	t	R-squared
0577-S-ES	RSI	-1.242	0.010	-120.0	35.6%
0875-S-ES	RSI	-1.385	0.012	-118.5	35.1%
0453-S-GB	RSI	-0.90	0.015	-58.8	20.8%
1340-S-GB	RSI	-0.87	0.015	-58.4	20.6%
1477-S-GB	RSI	-0.87	0.015	-56.4	19.5%
0436-S-DE	RSI	-2.36	0.034	-69.1	15.4%
0569-S-DE	RSI	-2.00	0.030	-66.7	14.5%
1338-S-DE	RSI	-2.43	0.042	-57.5	11.2%
1681-S-DE	RSI	-1.92	0.029	-67.0	14.6%
0511-S-NL	RSI	-1.22	0.021	-57.2	11.1%
0712-S-NL	RSI	-1.22	0.021	-57.2	11.1%

Source: LE

1.3.6.2 Multiple variable models

To test and develop our models and understanding further, we built and tested additional regression models. We tested the sensitivity of the models to violations in the classical linear regression assumptions and we tested a variety of specifications. We included dummy (zero-one) variables for peak and off peak, summer, winter, spring, and allowed the estimated RSI slope coefficients to vary with daily peak and off peak periods.[34] Additional explanatory variables were included to account for differences between modelled and actual generation by fuel type, competitive constraints posed by competitors and relative scarcity of available installed capacity. A number of further specifications included RSIs of more than one company as regressors explaining the margins. In general, with few exceptions, the RSI for large companies remained a statistically significant explanatory variable for price cost margins in all four countries.

1.4 Conclusions and summary

This study has been a comprehensive and quantitative investigation into the structure and functioning of six major EU electricity markets. Our study has been groundbreaking in a number of ways, but especially in that, it is the first in the EU to utilise generators' own data to estimate a system marginal cost and to subsequently construct market outcome measures based on these costs and relate them to detailed electricity specific structural measures.

[34] Additional regressions and model output details can be found in the country chapters.

The concentration of the markets was measured by traditional (CRn and HHI) and more innovative measures (RSI and PSI) of market structure. Concentration, in general as measured by traditional concentration measures, shows marked differences across country, but little variation over time or by method within countries. Some markets, such as GB, are borderline unconcentrated except in some hours where it can become concentrated (see chapter); others such as Spain, Germany and the Netherlands are moderately to highly concentrated, while France and Belgium are highly concentrated. Our results were, in general, not sensitive to a variety of factors and sensitivities, such as the allocation of the interconnector. In most cases, our qualitative conclusions were not sensitive to changes in assumptions. There were notable exceptions, such as the allocation of interconnection for the Netherlands (who controls what shares over the interconnector will likely change the overall picture of whether the Netherlands is a concentrated or unconcentrated market, however current domestic regulation can be seen to moderate this impact).

Results from the RSI threshold test show that broadly similar outcomes occur. The most concentrated markets fail the RSI threshold test in a very large percentage of hours, with respect to the largest companies (e.g., 100% in France and Belgium). On the other hand, in Great Britain the threshold test is breached in only a small number of hours across all of the companies assessed. Spain, the Netherlands and Germany have two companies with significant market positions approximately 20% to 77% of the time.

Comparing the market outcome measures (LI and PCMU) and the actual breakdown of costs also shows interesting results and differences across time and country. The differences across time were most interesting. All countries had large mark-ups in 2003, while countries diverged after that, with some country's margins falling (NL, DE) others rising (ES). Countries with lower costs seem to have higher margins for example, but no broad consensus correlation can be observed. GB had low margins, while the Netherlands had the lowest margins; but GB is less concentrated than the Netherlands. France had the highest margins but we view the results as not comparable to the others due to data difficulties. There are also important differences in margins across time. It is difficult to interpret these results, so the additional analysis of RSIs and regressions is needed. We also note again that the finding of negative margins is not uncommon in these types of studies[35].

Difficulties in the data created by reported available capacity and actual running capacity created challenges in modelling the marginal cost in France, and the lack of a good hourly price for Belgium meant that estimates of margins in these countries should be considered less reliable than in the other four. In addition, further analysis such as regressions, was not carried out for these countries.

[35] Negative margins are common because it is often the case that factors such as CHP and must-run units will continue to run even when the market price is below marginal cost. This may cause a near excess of energy on the system. In addition, many thermal units with long starting and stopping times will be willing to pay a premium to avoid shutting down and being thus unavailable to generate when prices are more profitable.

Of potentially greater interest is the breakdown of the power exchange price into components including carbon. We do not fully know whether companies have passed on the full cost of carbon or whether they have "raised" margins in response to carbon. In spite of the fact that utilities obtained their emissions allowances for free, one would expect them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities should in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment). What we can conclude from our results is that seemingly differential factors have occurred across countries, and the size of the margin changes across countries with the introduction of EU ETS, while the total marginal cost of carbon as estimated also changes.

We also compared estimates of the contribution to fixed costs. This section indicated that had the largest companies traded at the theoretically competitive price (equal to the estimated optimal marginal cost), they would have earned billions of euro towards their investment costs. This confirms the robustness of the model in terms of the overall level of estimated competitive price.

Finally, we estimated regression models for four countries using a variety of explanatory factors and specifications. The regression results included the estimation of the impact of RSI on margins and estimates including a variety of explanatory variables. The results showed that the RSI, a continuous measure of the indispensability of individual large suppliers, significantly explains market outcomes for almost all companies considered in all markets. This result is apparently robust to controlling for a number of factors, including model specification, changes in the assumptions of the statistical model, and inclusion of other explanatory factors such as scarcity, year, seasonality, and the modelled differences between actual and modelled generation of coal and gas. The results are consistent with the hypothesis that pivotalness gives firms market power in electricity markets, but does not necessarily prove this.

Of the evidence found, the most important is the detailed regression results. These results suggest that prices in the selected EU wholesale markets have been raised due to the pivotalness of particular suppliers. This suggests prices have not been as keen as they might have been.

It is difficult to say with 100% certainty whether any one country's market is exhibiting the exercise of market power. The regression results suggest that market structure is significantly related to market outcome measures in all the markets studied (DE, ES, NL and GB). In conclusion we can say that this report represents a considerable advancement in the state of knowledge about how electricity markets function (have been functioning) in Europe as previously, no such relation had been studied in such detail in the EU's major electricity markets.

Glossary

Available capacity	The capacity a generation plant has available to produce in any given hour or time period.
BPI	Belgian Power Index
CR(*n*)	Concentration ratio for the *n* largest firms
CHP	Combined heat and power
EEX	German hourly electricity spot price and market
EU ETS	The EU Emissions Trading Scheme
FERC	The US Federal Energy Regulatory Commission
Fixed cost	costs that do not vary with the amount of power produced
GED	Global Energy Decisions
GJ	Giga Joule
GWh	Gigawatt hour
Heat rate	Measure of the thermal efficiency of an electric generator in terms of thermal fuel input and electric energy output
HHI	Hirschman-Herfindahl index
Installed capacity	The capacity a plant is technically able to produce based on technology
kWh	Kilowatt hour
LE	London Economics
LI	Lerner Index: (P - MC)/P
Load	Hourly electricity demand on the system
Merit curve	The curve showing the unit cost (€/MWh) as a function capacity (MW) of each power plant on a system; the supply curve in a power system.
Merit order	The rank order of power plant on a system in terms of lowest to highest unit cost €/MWh
MW	Megawatt (capacity)
MWh	Megawatt hour
OMEL	Spanish hourly electricity spot price and market
PCMU	Price cost mark-up: (P - MC)/MC
Platts	An energy data company
PowerNext	French hourly electricity spot price and market
Prosym	An electricity market despatch simulation model based on GED's MARKETSYM software.
PSI	Pivotal supplier indicator
Regression	An econometric estimation technique used to find the impact of a number of independent variables on a dependent variable
RSI	Residual supply index
Start cost	Costs incurred by the generation station when starting
TSO	Transmission system operator
UKPX	UK hourly electricity spot price and market